

ABRAXAS PETROLEUM CORP

Form 10-K

March 18, 2010

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

FORM 10-K

(Mark One)

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

For the Fiscal Year Ended December 31, 2009

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

Commission File Number 001-16071

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

Nevada
(State or Other Jurisdiction of
Incorporation or Organization)

74-2584033
(I.R.S. Employer Identification Number)

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

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

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

Title of each class:	Name of each exchange on which registered:
Common Stock, par value \$.01 per share	The NASDAQ Stock Market, LLC
Preferred Stock Purchase Rights	The NASDAQ Stock Market, LLC

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

None

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

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

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

Indicate by check mark if the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes 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. Yes No

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.(check one):

Large accelerated filer Accelerated filer
Non-accelerated filer ☒ (Do not check if aSmaller 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 ☒

As of June 30, 2009, the last day of the registrant's most recently completed second fiscal quarter, the aggregate market value of the common stock held by non-affiliates of the registrant was \$43,053,752 based on the closing sale price as reported on The NASDAQ Stock Market

As of March 12, 2010, there were 76,230,187 shares of common stock outstanding.

Documents Incorporated by Reference:

Document	Parts Into Which Incorporated
Portions of the registrant's Proxy Statement relating to the 2010 Annual Meeting of Shareholders to be held on May 19, 2010.	Part III

ABRAXAS PETROLEUM CORPORATION
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FORWARD-LOOKING INFORMATION

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

- our success in development, exploitation and exploration activities;
 - our ability to make planned capital expenditures;
 - declines in our production of oil and gas;
 - prices for oil and gas;
- our ability to raise equity capital or incur additional indebtedness;
- 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;
 - weather conditions and events;
- the proximity, capacity, cost and availability of pipelines and other transportation facilities;
 - results of our hedging activities; and
- other factors discussed elsewhere in this document.

GLOSSARY OF TERMS

Unless otherwise indicated in this report, gas volumes are stated at the legal pressure base of the State or area in which the reserves are located at 60 degrees Fahrenheit. Oil and gas equivalents are determined using the ratio of six Mcf of gas to one barrel of oil, condensate or NGLs.

The following definitions shall apply to the technical terms used in this report.

Terms used to describe quantities of oil and gas:

“Bbl” – barrel or barrels.

“Bcf” – billion cubic feet of gas.

“Bcfe” – billion cubic feet of gas equivalent.

“Boe” – barrels of oil equivalent.

“Boepd” – barrels of oil equivalent per day.

“MBbl” – thousand barrels.

“MBoe” – thousand barrels of oil equivalent.

“Mcf” – thousand cubic feet of gas.

“Mcfe” – thousand cubic feet of gas equivalent.

“MMBbls” – million barrels.

“MMBoe” – million barrels of oil equivalent.

“MMbtu” – million British Thermal Units.

“MMcf” – million cubic feet of gas.

“MMcfe” – million cubic feet of gas equivalent.

“MMcfepd” – million cubic feet of gas equivalent per day.

“MMcfpd” – million cubic feet of gas per day.

Terms used to describe our interests in wells and acreage:

“Developed acreage” means acreage which consists of leased acres spaced or assignable to productive wells.

“Development well” is a well drilled within the proved area of an oil or gas reservoir to the depth of stratigraphic horizon (rock layer or formation) noted to be productive for the purpose of extracting proved oil or gas reserves.

“Dry hole” is an exploratory or development well found to be incapable of producing either oil or gas in sufficient quantities to justify completion as an oil or gas well.

“Exploratory well” is a well drilled to find and produce oil or gas in an unproved area, to find a new reservoir in a field previously found to be producing oil or gas in another reservoir, or to extend a known reservoir.

“Gross” means gross acres refer to the number of acres in which we own a working interest.

“Gross well” is a well in which we own an interest.

“Net acres” are deemed to exist when the sum of fractional ownership working interests in gross acres equals one (e.g., a 50% working interest in a lease covering 320 gross acres is equivalent to 160 net acres).

“Net well” is deemed to exist when the sum of fractional ownership working interests in gross wells equals one.

“Productive well” is an exploratory or a development well that is not a dry hole.

“Undeveloped acreage” means those leased acres on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and gas, regardless of whether or not such acreage contains proved reserves.

Terms used to assign a present value to or to classify our reserves:

“Proved reserves” or “reserves” means oil and gas, condensate and NGLs on a net revenue interest basis, found to be commercially recoverable.

“Probable reserves” are those additional reserves which analysis of geoscience and engineering data indicate are less likely to be recovered than proved reserves but more certain to be recovered than possible reserves.

“Possible reserves” are those additional reserves which analysis of geosciences and engineering data suggest are less likely to be recoverable than probable reserves.

“Proved undeveloped reserves” includes those proved reserves expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

“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 SEC.

“Standardized Measure” means estimated future net revenue, discounted at a rate of 10% per annum, after income taxes and with no price or cost escalation, calculated in accordance with ASC 932, formerly Statement of Financial Accounting Standards No. 69 “Disclosures About Oil and Gas Producing Activities.”

Part I

Item 1. Business

Information contained in this report represents the operations of Abraxas Petroleum Corporation and Abraxas Energy Partners, L.P., which we refer to as the Partnership or Abraxas Energy Partners, which are consolidated for financial reporting purposes. On October 5, 2009, Abraxas Petroleum Corporation acquired 100% ownership of the Partnership, which we refer to as the Merger. The non-controlling interest of the former limited partners of the Partnership is presented as non-controlling interest in the accompanying Consolidated Statement of Operations through the date that their interest was acquired by Abraxas. The terms “Abraxas,” “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 oil and gas. Historically, we have grown through the acquisition and subsequent development and exploitation 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, 2009, our properties were located in the Rocky Mountain, Mid-Continent, Permian Basin and Gulf Coast regions of the United States. The following table sets forth certain information related to our properties as of and for the year ended December 31, 2009:

	Gross Producing Wells	Average Working Interest		Estimated Net Proved Reserves (MMBOE)	Net Production (MBOE)
Rocky Mountain	900	12	%	7,237.1	434.8
Mid-Continent	617	14	%	3,109.0	263.1
Permian Basin	237	67	%	5,541.8	500.5
Gulf Coast	74	64	%	9,031.9	435.2
Total	1,828	22	%	24,919.8	1,633.6

Our Rocky Mountain properties consist of the following:

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

and the underlying Three Forks.

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

We have 900 gross (110 net) producing wells in the Rocky Mountain region.

Our Mid-Continent properties consist of the following:

- **Arkoma Basin**—Our properties in the Arkoma Basin are located in Oklahoma and Arkansas and consist of wells that mainly produce gas from Hartshorne coals at 3,000 feet.
- **Anadarko Basin**—Our properties in the Anadarko Basin are located in Oklahoma and the Texas Panhandle and consist of wells that mainly produce gas from Pennsylvanian-aged sandstones (Atoka/Morrow) from depths down to 18,000 feet.
- **ARK-LA-TEX**—Our properties in the ARK-LA-TEX region principally produce from the East Texas/North Louisiana Basins and include wells that produce oil and gas from various formations.

We have 617 gross (89 net) producing wells in the Mid-Continent region.

Our Permian Basin properties consist of the following:

- **ROC Complex**—Our properties in the ROC Complex are located in Pecos, Reeves and Ward Counties, Texas and consist of wells that produce oil and gas from multiple stacked formations from the Bell Canyon at 5,000 feet down to the Ellenburger at 16,000 feet.
- **Oates SW**—Our properties in the Oates SW area are located in Pecos County, Texas and consist of wells that produce gas from the Devonian formation at a depth of approximately 13,500 feet.
- **Eastern Shelf** – Our properties in the Eastern Shelf are predominately located in Coke, Scurry and Mitchell Counties, Texas and consist of wells that produce oil and gas from the Strawn Reef formation at 5,000 to 6,000 feet and oil from the shallower Clearfork formation at depths ranging from 2,300 to 3,300 feet.

We have 237 gross (158 net) producing wells in the Permian Basin region.

Our Gulf Coast properties consist of the following:

- **Edwards**— Our properties in the Edwards trend are located in DeWitt and Lavaca Counties, Texas and consist of wells that produce gas from the Edwards formation at a depth of 13,500 feet.
- **Portilla**—Our properties in the Portilla field are located in San Patricio County, Texas, were discovered in 1950 by The Superior Oil Company, predecessor to Mobil Oil Corporation, and consist of wells that produce oil and gas from the Frio sands and the deeper Vicksburg from depths of approximately 7,000 to 9,000 feet.
- **Wilcox** – Our properties in the Wilcox are located in Goliad, Bee, DeWitt and Karnes Counties, Texas and consist of wells that produce gas from various sands in the Wilcox formation at depths ranging from 8,000 to 11,000 feet.

We have 74 gross (48 net) producing wells in the Gulf Coast region.

Recent Developments

Merger Agreement

On June 30, 2009, Abraxas Petroleum and Abraxas Energy Partners signed an Agreement and Plan of Merger, which we refer to as the Original Merger Agreement, pursuant to which Abraxas Energy agreed to merge with and into Abraxas Petroleum with Abraxas Petroleum surviving and on July 17, 2009, Abraxas Petroleum, Abraxas Energy Partners and Abraxas Merger Dub, LLC, which we refer to as Merger Sub, signed an Amended and Restated Agreement and Plan of Merger, which we refer to as the Merger

Agreement, pursuant to which Abraxas Energy Partners agreed to merge with and into Merger Sub with Merger Sub surviving the merger as a wholly-owned subsidiary of Abraxas Petroleum. We refer to this merger as the Merger. Under the terms of the Merger Agreement, at the effective time of the Merger on October 5, 2009, which we refer to as the Effective Time, the common units of Abraxas Energy Partners not owned by Abraxas Petroleum and its subsidiaries were converted into the right to receive 4.25 shares of Abraxas Petroleum common stock for each Abraxas Energy Partners common unit not owned by Abraxas Petroleum or its subsidiaries. We issued a total of 26,174,061 shares of our common stock in the Merger, including 420,552 shares of restricted common stock issued in exchange for restricted units and phantom units of Abraxas Energy Partners under the Abraxas Petroleum Corporation 2005 Long-Term Equity Incentive Plan, or LTIP.

Credit Facility

Simultaneously with the closing of the Merger, we entered into an amended and restated senior secured credit facility with Société Générale, as administrative agent and issuing lender, and certain other lenders, which we refer to as the credit facility. In connection with the Merger, we borrowed \$145.0 million under the credit facility, of which \$135.0 million was borrowed under the revolving portion and \$10.0 million was borrowed under the term loan portion. As of December 31, 2009, \$138.5 million was outstanding under the revolving portion and \$8.0 million was outstanding under the term portion. For more information about the credit facility, see “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Long-Term Indebtedness—Credit Facility.

2010 Capital Budget

We anticipate making capital expenditures of \$30.0 million in 2010 for the development of our existing properties. The capital program for 2010 will be selected from our inventory of projects and will include new drills and re-completions / workovers in our primary producing regions of the Rocky Mountain, Mid-Continent, Permian Basin and onshore Gulf Coast. The ultimate mix of projects will be based on commodity prices, services costs and drilling results but will predominately target oil projects. These anticipated expenditures are subject to adequate cash flow from operations and availability under the credit facility.

Non-Core Divestitures

We have initiated a divestiture program, principally aimed at non-operated, non-core assets, to generate cash for debt repayment and to accelerate our drilling program. During the fourth quarter of 2009 and the first quarter of 2010, we have sold certain non-core assets for combined net proceeds of approximately \$11.2 million (\$2.4 million in 2009 and \$8.8 million in 2010). In total, these properties produced approximately 142 Boepd (approximately 3% of our daily net production) and had approximately 606 MBoe of proved reserves (approximately 2% of our net proved reserves), which equates to \$78,385 per producing Boepd and \$18.41 per proved Boe. The first \$10 million of net proceeds will be used to repay the term loan portion of our credit facility after which, any net proceeds will be allocated approximately 50% for further debt reduction and 50% to accelerate our capital program. We have identified an additional \$20 to \$30 million of similar non-core assets that we will attempt to divest on similar terms over the next several months.

Tax Benefits Preservation Plan

On March 16, 2010, our board of directors adopted a Tax Benefits Preservation Plan (the “Tax Benefits Preservation Plan”) and declared a dividend of one preferred share purchase right for each outstanding share of Abraxas common stock. The dividend is payable to our stockholders of record as of March 16, 2010. The terms of the rights and the

Tax Benefits Preservation Plan are set forth in a Rights Agreement, by and between us and American Stock Transfer & Trust Company, as Rights Agent, dated as of March 16, 2010.

This summary of rights provides only a general description of the Tax Benefits Preservation Plan.

We adopted the Tax Benefits Preservation Plan in an effort to protect stockholder value by attempting to protect against a possible limitation on our ability to use our net operating loss carryforwards, or NOL's, to reduce potential future federal income tax obligations. We have experienced and continue to experience substantial operating losses, and under the Internal Revenue Code and rules promulgated by the

Internal Revenue Service, we may “carry forward” these losses in certain circumstances to offset any current and future earnings and thus reduce our federal income tax liability, subject to certain requirements and restrictions. To the extent that the NOLs do not otherwise become limited, we believe that we will be able to carry forward a significant amount of NOLs, and therefore these NOLs could be a substantial asset to us. However, if we experience an “Ownership Change,” as defined in Section 382 of the Internal Revenue Code, our ability to use the NOLs will be substantially limited, and the timing of the usage of the NOLs could be substantially delayed, which could therefore significantly impair the value of that asset. As of December 31, 2009, we had net operating loss carryforwards of \$121.7 million.

The Tax Benefits Preservation Plan is intended to act as a deterrent to any person or group acquiring 4.9% or more of our outstanding common stock, or an Acquiring Person, without our approval. Stockholders who own 4.9% or more of our outstanding common stock as of the close of business on March 16, 2010 will not trigger the Tax Benefits Preservation Plan so long as they do not (i) acquire any additional shares of common stock or (ii) fall under 4.9% ownership of common stock and then re-acquire 4.9% or more of the common stock. The Tax Benefits Preservation Plan does not exempt any future acquisitions of common stock by such persons. Any rights held by an Acquiring Person are null and void and may not be exercised. We may, in our sole discretion, exempt any person or group from being deemed an Acquiring Person for purposes of the Tax Benefits Preservation Plan.

The Rights. We authorized the issuance of one right per each outstanding share of our common stock payable to our stockholders of record as of March 16, 2010. Subject to the terms, provisions and conditions of the Tax Benefits Preservation Plan, if the rights become exercisable, each right would initially represent the right to purchase from us one one-thousandth of a share of our Series 2010 Junior Participating Preferred Stock (“Series 2010 Preferred Stock”) for a purchase price of \$7.00 (the “Purchase Price”). If issued, each fractional share of Series 2010 Junior Preferred Stock would give the stockholder approximately the same dividend, voting and liquidation rights as does one share of our common stock. However, prior to exercise, a right does not give its holder any rights as a stockholder of the Company, including without limitation any dividend, voting or liquidation rights.

Series 2010 Preferred Stock Provisions. Each one one-thousandth of a share of Series 2010 Preferred Stock, if issued: (1) will not be redeemable; (2) will entitle holders to quarterly dividend payments of \$0.01 per one one-thousandth of a share of Series 2010 Preferred Stock, or an amount equal to the dividend paid on one share of common stock, whichever is greater, if, as and when declared by our board of directors out of funds legally available therefor; (3) will entitle holders upon liquidation either to receive \$1.00 per one one-thousandth of a share of Series 2010 Preferred Stock or an amount equal to the payment made on one share of common stock, whichever is greater; (4) will have the same voting power as one share of common stock; and (5) if shares of our common stock are exchanged via merger, consolidation, or a similar transaction, will entitle holders to a per share payment equal to the payment made on one share of common stock. The value of one one-thousandth interest in a Preferred Share should approximate the value of one share of common stock.

Exercisability. The rights will not be exercisable until the earlier of (i) 10 business days after a public announcement by us that a person or group has become an Acquiring Person or (ii) 10 business days after the commencement of a tender or exchange offer by a person or group for 4.9% of the common stock.

We refer to the date that the rights become exercisable as the “Distribution Date.” Until the Distribution Date, our common stock certificates will evidence the rights and will contain a notation to that effect. Any transfer of shares of common stock prior to the Distribution Date will constitute a transfer of the associated rights. After the Distribution Date, the rights may be transferred other than in connection with the transfer of the underlying shares of common stock.

After the Distribution Date, each holder of a right, other than rights beneficially owned by the Acquiring Person (which will thereupon become void), will thereafter have the right to receive upon exercise of a right and payment of the Purchase Price, that number of shares of common stock having a market value at the time of exercise of two times

the Purchase Price.

Exchange. After the Distribution Date, we may exchange the rights (other than rights owned by an Acquiring Person, which will have become void), in whole or in part, at an exchange ratio of one share of common stock, or a fractional share of Series 2010 Preferred Stock (or of a share of a similar class or series of the Company's preferred stock having similar rights, preferences and privileges) of equivalent value, per right (subject to adjustment).

Expiration. The rights and the Tax Benefits Preservation Plan will expire on the earliest of (i) March 16 2015, (ii) the time at which the rights are redeemed pursuant to the Rights Agreement, (iii) the time at which the rights are exchanged pursuant to the Rights Agreement, (iv) the repeal of Section 382 of the Code or any successor statute if we determine that the Rights Agreement is no longer necessary for the preservation of NOLs and (v) the beginning of a taxable year of the Company of which we determine that no NOLs may be carried forward.

Redemption. At any time prior to the time an Acquiring Person becomes such, we may redeem the rights in whole, but not in part, at a price of \$0.01 per right (the “Redemption Price”). The redemption of the rights may be made effective at such time, on such basis and with such conditions as we in our sole discretion may establish. Immediately upon any redemption of the rights, the right to exercise the rights will terminate and the only right of the holders of rights will be to receive the Redemption Price.

Anti-Dilution Provisions. We may adjust the purchase price of the shares of Series 2010 Preferred Stock, the number of shares Series 2010 Preferred Stock issuable and the number of outstanding rights to prevent dilution that may occur as a result of certain events, including among others, a stock dividend, a stock split or a reclassification of the shares of Series 2010 Preferred Stock or our common stock. No adjustments to the purchase price of less than 1% will be made.

Amendments. Before the Distribution Date, we may amend or supplement the Tax Benefits Preservation Plan without the consent of the holders of the rights. After the Distribution Date, we may amend or supplement the Tax Benefits Preservation Plan only to cure an ambiguity, to alter time period provisions, to correct inconsistent provisions, or to make any additional changes to the Tax Benefits Preservation Plan, but only to the extent that those changes do not impair or adversely affect any rights holder.

The rights have certain anti-takeover effects. The rights will cause substantial dilution to a person or group who attempts to acquire the Company on terms not approved by us. The rights should not interfere with any merger or other business combination approved by us since we may redeem the rights at \$0.01 per right at any time until the date on which a person or group has become an Acquiring Person.

Markets and Customers

The revenue generated by our operations is highly dependent upon the prices of oil and gas. Historically, the markets for oil and gas have been volatile and are likely to continue to be volatile in the future. The prices we receive for our oil and gas production are subject to wide fluctuations and depend on numerous factors beyond our control including seasonality, the condition of the United States economy (particularly the manufacturing sector), foreign imports, political conditions in other oil-producing and gas-producing countries, the actions of the Organization of Petroleum Exporting Countries and domestic regulation, legislation and policies. Decreases in the prices of oil and gas have had, and could have in the future, an adverse effect on the carrying value of our proved reserves and our revenue, profitability and cash flow from operations. You should read the discussion under “Risk Factors – Risks Relating to Our Industry — Market conditions for oil and gas, and particularly volatility of prices for oil and gas, could adversely affect our revenue, cash flows, profitability and growth” and “Management’s Discussion and Analysis of Financial Condition and Results of Operations – Critical Accounting Policies” for more information relating to the effects of decreases in oil and gas prices on us. To help mitigate the impact of commodity price volatility, we hedge a portion of our production through the use of fixed price swaps. See “Management’s Discussion and Analysis of Financial Condition and Results of Operations – General – Commodity Prices and Derivative Activities” and Note 12 of the notes to our consolidated financial statements for more information regarding our derivative activities.

Substantially all of our oil and gas is sold at current market prices under short-term arrangements, as is customary in the industry. During the year ended December 31, 2009, two purchasers accounted for approximately 21% of our gas sales, and no single purchaser accounted for more than 10% of our oil sales. We believe that there are numerous other

purchasers available to buy our oil and gas and that the loss of one or more of these purchasers would not materially affect our ability to sell oil and gas.

Regulation of Oil and Gas Activities

The exploration, production and transportation of all types of hydrocarbons are subject to significant governmental regulations. Our properties are affected from time to time in varying degrees by political developments and federal, state and local laws and regulations. In particular, oil and gas production operations and economics are, or in the past have been, affected by industry specific price controls,

taxes, conservation, safety, environmental and other laws relating to the petroleum industry, and by changes in such laws and by constantly changing administrative regulations.

Federal, state and local laws and regulations govern oil and gas activities. Operators of oil and gas properties are required to have a number of permits in order to operate such properties, including operator permits and permits to dispose of salt water. We possess all material requisite permits required by the states and other local authorities in which we operate properties. In addition, under federal law, operators of oil and gas properties are required to possess certain certificates and permits in order to operate such properties such as hazardous materials certificates, which we have obtained.

Development and Production

The operations of our properties are subject to various types of regulation at the federal, state and local levels. These types of regulation include requiring the operator of oil and gas properties to possess permits for the drilling and development of wells, post bonds in connection with various types of activities, and file reports concerning operations. Most states, and some counties and municipalities in which we operate, regulate one or more of the following:

- the location of wells;
- the method of developing and casing wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells; and
- notice to surface owners and other third parties.

Some states regulate the size and shape of development and spacing units or proration units for oil and gas properties. Some states allow forced pooling or unitization of tracts to facilitate exploitation while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum allowable rates of production from oil and gas wells, generally prohibit the venting or flaring of gas and impose requirements regarding the ratable production. These laws and regulations may limit the amount of oil and gas we can produce from their wells or limit the number of wells or the locations at which these wells can be drilled. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction.

Operations on Federal or Indian oil and gas leases 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, including the Bureau of Land Management, which we refer to as BLM, and the Minerals Management Service, which we refer to as MMS. MMS establishes the basis for royalty payments due under federal oil and natural gas leases through regulations issued under applicable statutory authority. State regulatory authorities establish similar standards for royalty payments due under state oil and natural gas leases. The basis for royalty payments established by MMS and the state regulatory authorities is generally applicable to all federal and state oil and natural gas leases. Accordingly, we believe that the impact of royalty

regulation on the operations of our properties should generally be the same as the impact on our competitors. We believe that the operations of our properties are in material compliance with all applicable regulations as they pertain to Federal or Indian oil and gas leases.

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

Regulation of Transportation and Sale of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938, as amended, which we refer to as NGA, the Natural Gas Policy Act of 1978, as amended, which we refer to as NGPA, and regulations promulgated thereunder by the

Federal Energy Regulatory Commission, which we refer to as FERC and its predecessors. In the past, the federal government has regulated the prices at which natural gas could be sold. Deregulation of wellhead natural gas sales began with the enactment of the NGPA. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, as amended, which we refer to as the Decontrol Act. The Decontrol Act removed all NGA and NGPA price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993. While sales by producers of natural gas can currently be made at unregulated market prices, Congress could reenact price controls in the future.

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

In 2000, FERC issued Order No. 637 and subsequent orders, which we refer to, collectively, as Order No. 637, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting. Most major aspects of Order No. 637 have been upheld on judicial review, and most pipelines' tariff filings to implement the requirements of Order No. 637 have been accepted by the FERC and placed into effect.

The Energy Policy Act of 2005, which we refer to as EP Act 2005, gave FERC increased oversight and penalty authority regarding market manipulation and enforcement. EP Act 2005 amended the NGA to prohibit market manipulation and also amended the NGA and the NGPA to increase civil and criminal penalties for any violations of the NGA, NGPA and any rules, regulations or orders of FERC to up to \$1,000,000 per day, per violation. In addition, FERC issued a final rule effective January 26, 2006, regarding market manipulation, which makes it unlawful for any entity, in connection with the purchase or sale of natural gas or transportation service subject to FERC jurisdiction, to defraud, make an untrue statement, or omit a material fact or engage in any practice, act, or course of business that operates or would operate as a fraud. This final rule works together with FERC's enhanced penalty authority to provide increased oversight of the natural gas marketplace.

The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach recently pursued by FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers, gatherers and marketers.

Generally, intrastate natural gas transportation is subject to regulation by state regulatory agencies, although FERC does regulate the rates, terms, and conditions of service provided by intrastate pipelines that transport gas subject to FERC's NGA jurisdiction pursuant to Section 311 of the NGPA. The basis for state regulation of intrastate natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect the operations of our properties in any way that is materially different from the effect of such regulation on

our competitors.

Natural Gas Gathering

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of the FERC. FERC has developed tests for determining which facilities constitute jurisdictional transportation facilities under the NGA and which facilities constitute gathering facilities exempt for FERC's NGA jurisdiction. From time to time, FERC reconsiders its test for defining non-jurisdictional gathering. For example, there is currently pending at FERC a proposed rulemaking to reformulate its test for non-jurisdictional gathering in the shallow waters of the Outer Continental Shelf. In recent years, FERC has also permitted jurisdictional pipelines to "spin down" exempt gathering facilities into affiliated entities that are not subject to FERC

jurisdiction, although FERC continues to examine the circumstances in which such a “spin down” is appropriate and whether it should reassert jurisdiction over certain gathering companies and facilities that previously had been “spun down.” We cannot predict the effect that FERC’s activities in this regard may have on the operations of our properties, but we do not expect these activities to affect the operations in any way that is materially different from the effect thereof on our competitors.

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

Regulation of Transportation of Oil

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

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

Environmental Matters

Oil and gas 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, areas inhabited by threatened or endangered species and other protected areas;

- require remedial measures to mitigate pollution from historical and on-going operations such as the 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 that the operators of properties are required to possess 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 our operations as well as the oil and gas industry in general, and thus we are unable to predict the ultimate cost and effects of future changes in environmental laws and regulations.

We are not currently involved in any administrative, judicial or legal proceedings arising under 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 respective financial positions or results of operations. Moreover, we maintain insurance against the 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.

The following is a discussion of the current relevant environmental laws and regulations that relate to our operations.

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

In the course of our ordinary operations, certain wastes may be generated that may fall within CERCLA’s definition of a “hazardous substance.” We may be liable under CERCLA or comparable state statutes for all or part of the costs required to clean up sites at which these wastes have been disposed. Although CERCLA currently contains a “petroleum exclusion” from the definition of “hazardous substance,” state laws affecting our operations impose cleanup liability relating to petroleum and petroleum related products, including oil cleanups.

We currently own or lease, and have in the past owned or leased, numerous properties that for many years have been used for the exploration and production of oil and gas. Although we have 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. Federal regulations also require certain owners and operators of facilities that store or otherwise handle oil to prepare and implement spill response plans relating to the potential discharge of oil into

surface waters. The Federal Oil Pollution Act, which we refer to as OPA, contains numerous requirements relating to prevention of, reporting of, and response to oil spills into waters of the United States. State laws mandate oil cleanup programs with respect to contaminated soil. A failure to comply with OPA's requirements or inadequate cooperation during a spill response action may subject a responsible party to civil or criminal enforcement actions. We are not aware of any action or event that would subject us to liability under OPA, and we believe that compliance with OPA's financial responsibility

and other operating requirements will not have a material adverse effect on our financial position or results of operations.

Resource Conservation Recovery Act. The Resource Conservation and Recovery Act, which we refer to as RCRA, is the principal federal statute governing the treatment, storage and disposal of hazardous and non-hazardous solid wastes. RCRA imposes stringent operating requirements, and liability for failure to meet such requirements, on a person who is either a “generator” or “transporter” of hazardous waste or an “owner” or “operator” of a hazardous waste treatment, storage or disposal facility. At present, RCRA includes a statutory exemption that allows most oil and gas exploration and production wastes to be classified and regulated as non-hazardous wastes. A similar exemption is contained in many of the state counterparts to RCRA. At various times in the past, proposals have been made to amend RCRA to rescind the exemption that excludes oil and gas exploration and production wastes from regulation as hazardous wastes. 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 and would cause us to incur increased operating expenses. Also, in the ordinary course of our operations, we generate small amounts of ordinary industrial wastes, such as paint wastes, waste solvents and waste oils that may be regulated as hazardous wastes.

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

Clean Water Act. The Clean Water Act, which we refer to as the CWA, and analogous state laws, impose restrictions and controls on the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by EPA or an analogous state agency. The CWA regulates storm water run-off from oil and natural gas facilities and requires a storm water discharge permit for certain activities. Such a permit requires the regulated facility to monitor and sample storm water run-off from its operations. The CWA and regulations implemented thereunder also prohibit discharges of dredged and fill material in wetlands and other waters of the United States unless authorized by an appropriately issued permit. Spill prevention, control and countermeasure requirements of the CWA require appropriate containment berms and similar structures to help prevent the contamination of waters of the United States in the event of a petroleum hydrocarbon tank spill, rupture or leak. The CWA and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges for oil and other pollutants and impose liability on parties responsible for those discharges for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. We believe that the operations of our properties comply in all material respects with the requirements of the CWA and state statutes enacted to control water pollution.

Safe Drinking Water Act. Our operations also produce wastewaters that are disposed via underground injection wells. These activities are regulated by the Safe Drinking Water Act, which we refer to as the SDWA, and analogous state and local laws. Underground injection is the subsurface placement of fluid through a well, such as the reinjection of brine produced and separated from oil and gas production. The main goal of the SDWA is 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 most states, no underground injection may take place

except as authorized by permit or rule. We currently own and operate various underground injection wells. Failure to abide by our permits could subject us to civil and/or criminal enforcement. We believe that we are in compliance in all material respects with the requirements of applicable state underground injection control programs and our permits.

Clean Air Act. The Clean Air Act, which we refer to as the CAA, and state air pollution laws and regulations provide a framework for national, state and local efforts to protect air quality. The operations of our properties utilize equipment that emits air pollutants which may be subject to federal and state air pollution control laws. These laws require utilization of air emissions abatement equipment to achieve prescribed emissions limitations and ambient air quality standards, as well as operating permits for existing equipment and construction permits for new and modified equipment.

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

Hydraulic Fracturing. Many of our operations depend on the use of hydraulic fracturing to enhance production from oil and gas wells. This technology involves the injection of fluids—usually consisting mostly of water but typically including small amounts of chemical additives—as well as sand into a well under high pressure in order to create fractures in the rock that allow oil or gas to flow more freely to the wellbore. Many of our newer wells would not be economical without the use of hydraulic fracturing to stimulate production from the well. Hydraulic fracturing operations have historically been overseen by state regulators as part of their oil and gas regulatory programs. However, bills have recently been introduced in Congress that would subject hydraulic fracturing to federal regulation under the Safe Drinking Water Act. If adopted, these bills could result in additional permitting requirements for hydraulic fracturing operations as well as various restrictions on those operations. These permitting requirements and restrictions could result in delays in operations at existing and new well sites as well as increased costs to make our wells productive. Moreover, the bills introduced in Congress would require the public disclosure of certain information regarding the chemical makeup of hydraulic fracturing fluids, many of which are proprietary to the service companies that perform the hydraulic fracturing operations. If enacted, these laws could make it easier for third parties to initiate litigation against us in the event of perceived problems with drinking water wells in the vicinity of an oil or gas well or other alleged environmental problems. In addition to these federal legislative proposals, some states and local governments have considered imposing various conditions and restrictions on hydraulic fracturing operations, including but not limited to requirements regarding chemical disclosure, casing and cementing of wells, withdrawal of water for use in high-volume hydraulic fracturing of horizontal wells, baseline testing of nearby water wells, and restrictions on the type of additives that may be used in hydraulic fracturing operations. If these types of conditions are adopted, we could be subject to increased costs and possibly limits on the productivity of certain wells.

Climate change legislation and greenhouse gas regulation. Studies over recent years have indicated that emissions of certain gases may be contributing to warming of the Earth's atmosphere. In response to these studies, many nations have agreed to limit emissions of "greenhouse gases" or "GHGs" pursuant to the United Nations Framework Convention on Climate Change, and the "Kyoto Protocol." Methane, a primary component of natural gas, and carbon dioxide, a byproduct of the burning of oil, natural gas, and refined petroleum products, are considered "greenhouse gases" regulated by the Kyoto Protocol. Although the United States is not participating in the Kyoto Protocol, several states have adopted legislation and regulations to reduce emissions of greenhouse gases. Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect our operations and demand for our products. Additionally, the United States Supreme Court has ruled, in *Massachusetts, et al. v. EPA*, that the EPA abused its discretion under the Clean Air Act by refusing to regulate carbon dioxide emissions from mobile sources. As a result of the Supreme Court decision and the change in presidential administrations, on December 7, 2009, the EPA issued a finding that serves as the foundation under the Clean Air Act to issue other rules that would result in federal greenhouse gas regulations and emissions limits under the Clean Air Act, even without Congressional action. As part of this array of new regulations, on September 22, 2009, the EPA also issued a GHG monitoring and reporting rule that requires certain parties, including participants in the oil and natural gas industry, to monitor and report their GHG emissions, including methane and carbon dioxide, to the EPA. The emissions will be published on a register to be made available on the Internet. These regulations may apply to our operations. The EPA has proposed two other rules that would regulate GHGs, one of which would regulate GHGs from stationary sources, and may

affect sources in the oil and natural gas exploration and production industry and the pipeline industry. The EPA's finding, the greenhouse gas reporting rule, and the proposed rules to regulate the emissions of greenhouse gases would result in federal regulation of carbon dioxide emissions and other greenhouse gases, and may affect the outcome of other climate change lawsuits pending in United States federal courts in a manner unfavorable to our industry.

On June 26, 2009, the United States House of Representatives approved adoption of the “American Clean Energy and Security Act of 2009,” also known as the “Waxman-Markey cap-and-trade legislation” or ACESA. On November 5, 2009 the Senate Committee on Environment and Public Works approved the “Clean Energy Jobs and American Power Act of 2009,” authored by John Kerry and Barbara Boxer, that is similar in many ways to ACESA. One of the purposes of these bills is to control and reduce emissions of greenhouse gases in the United States. These bills would establish an economy-wide cap on emissions of GHGs in the United States and would require an overall reduction in GHG emissions of 17% to 20% (from 2005 levels) by 2020, and by over 80% by 2050. Under these bills, most sources of GHG emissions would be required to obtain GHG emission “allowances” corresponding to their annual emissions of GHGs. The number of emission allowances issued each year would decline as necessary to meet the overall emission reduction goals of the bills. As the number of GHG emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The net effect of these bills would be to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products, and natural gas. President Obama has indicated that he is in support of the adoption of legislation such as the two bills discussed above, and the White House is expending significant efforts to push for the legislation.

Two recent court decisions, one before the United States Second Circuit Court of Appeals and one before the United States Fifth Circuit Court of Appeals have allowed GHG related cases to proceed. In the first case, *Connecticut v. American Electric Power*, the Second Circuit ruled that several states and other plaintiffs could continue a suit to impose GHG reductions on several utility defendants, concluding that a political question and standing objections of the defendants did not prohibit the suit from going forward. The Fifth Circuit, in *Comer v. Murphy Oil*, ruled that plaintiffs could similarly pursue a damage suit and the political question did not prohibit the suit. This case involves claims by plaintiffs who suffered damages from Hurricane Katrina that are seeking to recover damages from certain GHG emitters asserting their emissions contributed to their increased damages. In another case filed in the State District Court in Austin, Texas on October 6, 2009, a citizens group sued the Texas Commission on Environmental Quality (TCEQ) asserting that the agency was required to regulate carbon dioxide emissions from parties applying for permits under the Texas Clean Air Act. The result of this lawsuit could impose additional regulations on our operations, if the Texas courts require the TCEQ to regulate carbon dioxide and perhaps other GHGs such as methane, and these rules are applied to our operations in Texas. We may be subject to the EPA GHG monitoring and reporting rule, and potentially new EPA permitting rules if adopted to apply GHG permitting obligations and emissions limitations under the federal Clean Air Act. Even if no federal greenhouse gas regulations are enacted, or if the EPA issues regulations, more than one-third of the states have begun taking action on their own to control and/or reduce emissions of greenhouse gases. Several multi-state programs have been developed or are in the process of being developed: the Regional Greenhouse Gas Initiative involving 10 Northeastern states, the Western Climate Initiative involving seven western states, and the Midwestern Greenhouse Gas Reduction Accord involving seven states. The latter two programs have several other states acting as observers and they may join one of the programs at a later date. Any of the climate change regulatory and legislative initiatives described above could have a material adverse effect on our business, financial condition, and results of operations.

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

Endangered Species Act. The Endangered Species Act, which we refer to as the ESA, restricts activities that may affect endangered or threatened species or their habitats. While some of our properties may be located in areas that

may be designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. However, the discovery of previously unidentified endangered or threatened species could cause us to incur additional costs or become subject to operating restrictions or bans in the affected areas.

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

Title to Properties

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

Competition

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

Employees

As of March 12, 2010, we had 70 full-time employees. We retain independent geological, land and engineering consultants from time to time on a limited basis and expect to continue to do so in the future.

Available Information

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

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

Item 1A. Risk Factors

Risks Related to Our Business

We have substantial indebtedness which may adversely affect our cash flow and business operations.

At December 31, 2009, we had a total of \$146.5 million of indebtedness under our credit facility. Our indebtedness could have important consequences to us, including:

- our ability to obtain additional financing, if necessary, for working capital, capital expenditures, acquisitions or other purposes may be impaired or such financing may not be available on favorable terms;

- covenants contained in our credit facility and future debt arrangements will require us to meet financial tests that may affect our flexibility in planning for and reacting to changes in our business, including possible acquisition opportunities;
- we may need a substantial portion of our cash flow from operations to make principal and interest payments on our indebtedness, reducing the funds that would otherwise be available for operations and future business opportunities; and
- our level of debt will make us more vulnerable to competitive pressures or a downturn in our business or the economy generally, than our competitors with less debt.

Our ability to service our indebtedness will depend upon, among other things, our future financial and operating performance, which will be affected by prevailing economic conditions and financial, business, regulatory and other factors, some of which are beyond our control. If our operating results are not sufficient to service our current or future indebtedness, we will be forced to take actions such as reducing or delaying acquisitions and/or capital expenditures, selling assets, restructuring or refinancing our indebtedness or seeking additional debt or equity capital or bankruptcy protection. We may not be able to effect any of these remedies on satisfactory terms or at all.

A breach of the terms and conditions of the credit facility, including the inability to comply with the required financial covenants, could result in an event of default. If an event of default occurs (after any applicable notice and cure periods), the lenders would be entitled to terminate any commitment to make further extensions of credit under the credit facility and to accelerate the repayment of amounts outstanding (including accrued and unpaid interest and fees). Upon a default under the credit facility, the lenders could also foreclose against any collateral securing such obligations, which may be all or substantially all of our assets. If that occurred, we may not be able to continue to operate as a going concern.

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

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

Volatility in oil and gas prices, the timing of our drilling programs and drilling results will affect our cash flow from operations. Lower prices and/or lower production will also decrease revenues and cash flow, thus reducing the amount of financial resources available to meet our capital requirements, including reducing the amount available to pursue our drilling opportunities. If our cash flow from operations does not increase as a result of 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 base under our credit facility will be determined from time to time by the lenders. Reductions in estimates of oil and gas reserves could result in a reduction in the borrowing base, which would reduce the amount of financial resources available under the credit facility to meet our capital requirements. Such a reduction could be the result of lower commodity prices and/or production, inability to drill or unfavorable drilling results, changes in oil and gas reserve engineering, the lenders' inability to agree to an adequate borrowing base or adverse changes in the lenders' practices regarding estimation of reserves.

If cash flow from operations or our borrowing base decrease for any reason, our ability to undertake exploration and development activities could be adversely affected. As a result, our ability to replace production may be limited. In

addition, if the borrowing base under the credit facility is reduced, we would be required to reduce our borrowings under the credit facility so that such borrowings do not exceed the borrowing base. This could further reduce the cash available to us for capital spending and, if we did not have sufficient capital to reduce our borrowing level, we may be in default under the credit facility.

We have sold producing properties to provide us with liquidity and capital resources in the past and we may continue to do so in the future. After any such sale, we would expect to utilize the

proceeds to reduce our indebtedness and to drill new wells on our remaining properties. If we cannot replace the production lost from properties sold with production from the remaining properties, our cash flow from operations will likely decrease, which in turn, would decrease the amount of cash available for additional capital spending.

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

Our future oil and gas production, and therefore our success, is highly dependent upon our ability to find, acquire and develop additional reserves that are profitable to produce. The rate of production from our oil and gas properties and our proved reserves will decline as our reserves are produced. Unless we acquire additional properties containing proved reserves, conduct successful development and exploration activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves, we cannot assure you that our exploration and development activities will result in increases in our proved reserves. Approximately 93% of the estimated ultimate recovery of our proved developed producing reserves as of December 31, 2009 had been produced. Based on the reserve information set forth in our reserve report as of December 31, 2009, our average annual estimated decline rate for our net proved developed producing reserves is 13% during the first five years, 8% in the next five years, and approximately 7% thereafter. These rates of decline are estimates and actual production declines could be materially higher. While we have had some success in finding, acquiring and developing additional reserves, we have not always been able to fully replace the production volumes lost from natural field declines and prior property sales. As our proved reserves and consequently our production decline, our cash flow from operations, and the amount that we are able to borrow under our credit facility will also decline. In addition, approximately 44% of our total estimated proved reserves at December 31, 2009 were classified as 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.

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

We cannot assure you that the new wells we drill will be productive or that we will recover all or any portion of our capital investment. Drilling for oil and gas may be unprofitable. Dry holes and wells that are productive but do not produce sufficient net revenues after drilling, operating and other costs are unprofitable. The inherent risk of not finding commercially productive reservoirs will be compounded by the fact that 44% of our total estimated proved reserves as of December 31, 2009 were classified as undeveloped. By their nature, estimates of undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations. In addition, our properties may be susceptible to drainage from production by other operations on adjacent properties. If the volume of oil and gas we produce decreases, our cash flow from operations will decrease.

Our drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors that are beyond our control or not covered by insurance.

Our drilling operations are subject to a number of risks, 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;

- title problems;

- unusual or unexpected geological formations;
- pipeline ruptures;
- fires, blowouts and explosions; and
- uncontrollable flows of oil or gas or well fluids.

Any of these events could adversely affect our ability to conduct operations or cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution or other environmental contamination, loss of wells, regulatory penalties, suspension of operations, and attorney's fees and other expenses incurred in the prosecution or defense of litigation.

We maintain insurance against some but not all of these risks. Additionally, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could therefore occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. The occurrence of an event that is not fully covered by insurance could have a material adverse impact on our business activities, financial condition and results of operations.

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.

Our credit facility contains a number of significant covenants that, among other things, limit our ability to:

- incur or guarantee additional indebtedness and issue certain types of preferred stock or redeemable stock;
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