ABRAXAS PETROLEUM CORP
Form 10-K/A
October 13, 2011

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

FORM 10-K/A Number 1

(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, 2010

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	74-2584033
(State or Other Jurisdiction of Incorporation or Organization)	(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 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 xNo

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 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. Yesx 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 x
Non-accelerated filer (Do not check 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, 2010, 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 $191,912,033 based on the closing sale price as reported on The NASDAQ Stock Market.

As of March 11, 2011, there were 91,561,792 shares of common stock outstanding.

Documents Incorporated by Reference:

Document	Parts Into Which Incorporated
Portions of the registrant's Proxy Statement relating to the 2011 Annual Meeting of Stockholders to be held on May 5, 2011.	Part III

ABRAXAS PETROLEUM CORPORATION
FORM 10-K
TABLE OF CONTENTS

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 Securities and Exchange Commission (the “SEC”). Except for Items 1A and 2, no other information included in the original report on Form 10-K filed on March 16, 2011 (the “Original Form 10-K”) is amended by this Form 10-K/A Number 1. For convenience, we have repeated all of Part I (Items 1, 1A, 1B, 2, 3 and 4) of 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, 2010, originally filed with the SEC on March 16, 2011.In addition, in connection with filing this Amendment and pursuant to the rules of the Commission, the company’s Chief Executive Officer and Chief Financial Officer have reissued their certifications pursuant to section 302 of the Sarbanes-Oxley Act of 2002, attached as Exhibits 31.1 and 31.2 to this Amendment. Because no financial statements are contained within this Amendment, we are not including certifications pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
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 report. Whenever you read a statement that is not simply a statement of historical fact (such as statements including words like “believe,” “expect,” “anticipate,” “intend,” “may,” “g “plan,” “seek,” “estimate,” “could,” “potentially” or similar expressions), you must remember that these are forward-looki statements, and that our expectations may not be correct, even though we believe they are reasonable. The forward-looking information contained in this report 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 o 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 procure services and equipment for our drilling and completion activities;
- our ability to make planned capital expenditures;
- declines in our production of oil and gas;
- the prices we receive for our oil and gas and the effectiveness of our hedging activities;
- the availability of capital;
- 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; 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.

"Bopd" – barrels of oil 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 of gas.

"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 or 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 acres" are 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” are those quantities of oil and gas reserves, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation.

“Proved developed reserves” or “PDP’s” are those quantities of oil and gas reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. Additional oil and gas expected to be obtained through the application of fluid injection or other improved recovery techniques for supplementing the natural forces and mechanisms of primary recovery are included in “proved developed reserves” only after testing by a pilot project or after the operation of an installed program has confirmed through production response that increased recovery will be achieved.

“Proved developed non-producing reserves” or “PDNP’s” are those quantities of oil and gas reserves that are developed behind pipe in an existing well bore, from a shut-in well bore or that can be recovered through improved recovery only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells that were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to the start of production.

“Proved undeveloped drilling location” is a site on which a development well can be drilled consistent with spacing rules for purposes of recovering proved undeveloped reserves.

“Proved undeveloped reserves” or “PUD’s” are those quantities of oil and gas reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for development. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units are claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proven effective by actual tests in the area and in the same reservoir.

“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 geoscience and engineering data suggest are less likely to be recoverable than probable reserves.

“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

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, 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 Corporatio together with its consolidated subsidiaries including Abraxas Energy Partners, L.P., unless the context otherwise requires. Blue Eagle Energy, LLC ("Blue Eagle") is a joint venture between us and Rock Oil Company, LLC ("Rock Oil") to develop the Eagle Ford shale play in South Texas. We currently own an approximate 50% equity interest in Blue Eagle.

Item 1. Business

General

We are an independent energy company primarily engaged in the acquisition, exploitation, development and production of oil and gas in the United States and Canada. At December 31, 2010, our estimated net proved reserves were 26.6 MMBoe, (including our 50% equity interest in the proved reserves of Blue Eagle), of which 51% were classified as proved developed, 42% were oil and 83% were operated. Our daily net production for the year ended December 31, 2010 was 3,896 Boepd, of which 36% was oil or liquids.

Our oil and gas assets are located in four operating regions in the United States, the Rocky Mountain, Mid-Continent, Permian Basin and onshore Gulf Coast, and in the province of Alberta, Canada. The following table sets forth certain information related to our properties as of and for the year ended December 31, 2010:

	Gross Producing Wells	Average Working Interest		Total Net Acres	Estimated Net Proved Reserves (MBOE)	Net Production (MBOE)
Rocky Mountain	896	11.64	%	81,990	8,443.4	385.4
Mid-Continent	147	22.68	%	5,769	1,508.4	203.1
Permian Basin	210	74.43	%	38,951	5,552.8	464.1
Onshore Gulf Coast (1)	53	87.89	%	7,776	10,924.6	368.6
Total United States	1,306	26.13	%	134,486	26,429.2	1,421.2
Alberta, Canada	1	100.00	%	9,120	141.4	0.9
Total	1,307	26.13	%	143,606	26,570.6	1,422.1

(1) Includes 2,622.8 MBOE of estimated proved reserves attributable to our 50% equity interest in Blue Eagle.

Our properties in the Rocky Mountain region are located in the Williston Basin of North Dakota and Montana and in the Green River, Powder River and Unita Basins of Wyoming and Utah. In this region, our wells produce oil and gas from various reservoirs, including the Niobrara, Bakken and Three Forks formations. Well depths range from 7,000 feet down to 12,000 feet. We have 896 gross (104 net) producing wells in the Rocky Mountain region.

Our properties in the Mid-Continent region are primarily located in the Arkoma Basin and principally produce gas from the Hartshorne coals at 3,000 feet.We have 147 gross (33 net) producing wells in the Mid-Continent region.

Our properties in the Permian Basin region are primarily located in two sub-basins, the Delaware Basin and the Eastern Shelf. In the Delaware Basin, our wells are located in Pecos, Reeves, and Ward Counties, Texas and produce oil and gas from multiple stacked formations from the Bell Canyon at 5,000 feet down to the Ellenburger at 16,000 feet. In the Eastern Shelf, our wells are principally located in Coke, Scurry, Midland, Mitchell and Nolan Counties, Texas and 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 210 gross (156 net) producing wells in the Permian Basin region.

Our properties in the onshore Gulf Coast region are located along the Edwards trend in DeWitt and Lavaca Counties, Texas and in the Portilla field in San Patricio County, Texas. In the Edwards trend, our wells produce gas from the Edwards formation at a depth of 13,500 feet and in the Portilla field, our wells produce oil and gas from the Frio sands and the deeper Vicksburg from depths of approximately 7,000 to 9,000 feet. We have 53 gross (47 net) producing wells in the onshore Gulf Coast region.

Our properties in the province of Alberta, Canada are located in the Pekisko fairway and the Nordegg/Tomahawk area of Central Alberta. Our one gross / net well produces oil and associated gas from the Pekisko formation at a depth of approximately 5,400 feet.

Strategy

Our business strategy is to provide long term growth in net asset value per share by increasing daily production and proved reserves over time as well as adding to our inventory of development projects on both our unconventional and conventional oil and gas assets, while maintaining a conservative leverage position to enhance financial flexibility. Key elements of our business strategy include:

Developing our drilling inventory. Through our existing acreage position, we have a multi-year drilling inventory in excess of 300 net potential drilling locations (based on standard industry spacing parameters and management estimates) in our unconventional and conventional plays. We plan to focus our development efforts in 2011 on the oil and liquids-rich Bakken, Three Forks, Eagle Ford, Pekisko and Niobrara formations, as well as our Texas oil plays. We will continue to pursue acreage acquisitions in an effort to increase and enhance our core acreage positions.

Maintaining a mix of operated and non-operated leasehold positions in our resource plays. While developing our resource plays, we plan on maintaining a mix of operated and non-operated interests. As operator, we retain more control over the timing, selection and process of drilling prospects and completion design, which enhances our ability to maximize return on invested capital and gives us greater control over the timing, allocation, and amounts of our capital expenditures. As a non-operated working interest partner, we believe we can leverage our partners’ knowledge and experience and potentially reduce our costs and enhance our returns.

Increasing the oil component of our production and proved reserves. By focusing our 2011 drilling activity in the oil and liquids-rich resource plays, we expect to increase the oil/liquids component of both our production and proved reserves. Our goal for 2011 is a 50/50 mix of oil/liquids and gas production, as compared to our 36/64 mix of oil/liquids and gas production for the year ended December 31, 2010. Our proved reserves at December 31, 2010 were 41% oil/liquids and 59% gas.

Maintaining financial flexibility. As a result of our recently completed public offering of shares of our common stock, we have approximately $60.0 million available under our credit facility. We anticipate that our primary sources of capital will be availability under our credit facility and cash flow from operations. We plan on deploying our available capital in a cost-effective manner by developing our assets in areas where drilling and service costs are relatively lower and equipment and crews more readily available. For example, because service costs have recently escalated dramatically in the Williston Basin due to a shortage of equipment and crews, we intend to focus our drilling activities in other areas during the first half of 2011 until equipment and crews become more readily available.

2011 Budget and Drilling Activities

We have expanded our capital expenditure budget for 2011 to $60 million, an increase of approximately 66% over 2010. Approximately 50% of the expanded 2011 budget will be spent on unconventional horizontal oil wells in the Bakken/Three Forks and Niobrara plays in the Rocky Mountain region of the United States and the other 50% will target conventional oil plays in the Permian Basin and onshore Gulf Coast regions of the United States and in the province of Alberta, Canada. The 2011 capital expenditure budget is subject to change depending upon a number of factors, including the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the availability of sufficient capital resources, the results of our exploitation efforts, and our ability to obtain permits for drilling locations.

We have a substantial inventory of undeveloped acreage in several unconventional and conventional basins, or plays, exposing us to significant resource potential which will be the focus of our development plans in 2011. Our acreage in the unconventional plays includes the Williston Basin focused on the Bakken and Three Forks formations; the onshore Gulf Coast Basin focused on the Eagle Ford Shale; the Powder River Basin focused on the Niobrara Shale; and the Southern Alberta Basin focused on the Bakken formation. Our acreage in the conventional plays includes the Western Alberta Basin focused on the Pekisko formation and several oil plays in Texas focused on the Strawn, Frio and Yates formations. Our net acreage position for each basin or play is detailed in the following table:

Basin/Play	Targeted Formation(s)		Net Acres	
Williston	Bakken / Three Forks		20,835	
Onshore Gulf Coast	Eagle Ford		8,333	(1)
Powder River	Niobrara		18,700	
Western Alberta	Pekisko		9,120	
Southern Alberta	Bakken		10,000	
Texas Oil Plays	Strawn / Frio / Yates		8,700	
		Total	75,688	

(1) All of the acreage in the Eagle Ford Shale play is owned by Blue Eagle.

In 2011, we intend to concentrate our drilling activities in the following unconventional and conventional resource plays:

Williston Basin - Bakken/Three Forks. We currently own approximately 20,835 net acres, primarily in counties located on the Nesson Anticline and in areas west including Rough Rider and Lewis & Clark in North Dakota and in Sheridan County, Montana, which are prospective for the Bakken and Three Forks formations. We estimate that we have approximately 86 gross (16 net) 1,280-acre units. In 2010, we drilled two operated wells and participated in an additional 10 gross (0.35 net) non-operated wells on the North Dakota side of the basin. Our first operated well, the Ravin 26-35 1H was drilled in McKenzie County, North Dakota and was brought on-line at a restricted rate in November 2010. In January 2011, the well was flow tested at an unrestricted production rate of 1,705 Boepd, comprised of 1,008 barrels of oil, 2.44 MMcf of wellhead gas and 290 barrels of natural gas liquids. Our second operated well is tentatively scheduled to be completed in the second quarter of 2011. In 2011, we plan to drill up to five operated horizontal long lateral wells and participate in several additional non-operated wells targeting the Bakken or Three Forks formations.

Onshore Gulf Coast Basin - Eagle Ford. In August 2010, we formed a joint venture, Blue Eagle, with Rock Oil to develop our acreage in the Eagle Ford Shale play. We contributed 8,333 net acres, located in Atascosa, DeWitt and Lavaca Counties, Texas, and received an approximate 50% equity interest in Blue Eagle, and Rock Oil contributed $25 million in cash and received an approximate 50% equity interest. Rock Oil also committed to contribute an additional $50 million in cash. Upon full funding by Rock Oil, we will own a 25% equity interest and Rock Oil will own a 75% equity interest in Blue Eagle.

In 2010, Blue Eagle drilled one well and completed the well in January 2011. The well was completed with a 15-stage fracture stimulation and placed on-line in January 2011 at a restricted rate. During the first 19 days of producing through a 12/64-inch choke, the well produced an average of 5.8 MMcf of liquids-rich gas and 342 barrels of condensate per day. We anticipate that Blue Eagle will drill or participate in four additional wells in 2011, all of which will be fully funded by Blue Eagle. Based on 160-acre spacing, we estimate that there are 52 net drilling locations across the Blue Eagle acreage.

Powder River Basin - Niobrara. We currently own a total of approximately 20,800 gross (18,700 net) acres in the southern Powder River Basin, of which 17,800 gross (15,700 net) acres are located in the Brooks Draw field of Converse and Niobrara Counties, Wyoming. Prior to 2010, we drilled a total of 12 wells, including seven horizontal wells, and acquired a 23-square mile proprietary 3-D seismic survey in the Brooks Draw field. In addition, we own approximately 2,100 net acres in Campbell County, Wyoming which are held by production and are near the Crossbow 3-19H well operated by EOG Resources, Inc. in southern Campbell County, Wyoming and other recent horizontal activity. In 2011, we have budgeted the drilling of one horizontal well targeting the Niobrara formation in the Brooks Draw field; however, we may elect to increase our activity in the area pending results of this well. Based on 160–acre spacing and assuming all of the acreage is productive, we estimate that there are 117 net drilling locations on our held by production leasehold.

Alberta Basin - Pekisko. We currently own 9,120 net acres in Central Alberta. In 2010, we drilled two wells in the Twining area as part of a farm-out agreement. One of the wells, the Twining 9-11, came on-line in the first quarter of 2011 and produced an average of 108 Boepd (73% oil) during the first 18 days of production. The other well, the Swalwell 6-6, will be re-completed in the summer of 2011. Our budget for 2011 currently includes the drilling of four horizontal wells targeting the Pekisko formation.

Alberta Basin – Bakken. In the emerging southern Alberta Basin Bakken play of Toole and Glacier Counties, Montana, we currently own approximately 10,000 gross/net acres under long-term leases or direct mineral ownership. During 2010, we acquired our leasehold position and monitored industry activity in the play, principally by Rosetta Resources Inc. and Newfield Exploration Company, and continued our own independent study of the play. During 2011, we intend to continue to acquire additional acreage in the geologically specific parts of the play.

Texas Oil Plays

Permian Basin – Spires Ranch – Strawn. We currently own approximately 5,600 gross/net acres in Nolan County, Texas. In 2009 and 2010, we drilled three wells in the Spires Ranch offsetting the prolific Nena Lucia field. The first well encountered a thick oil column but was pressure depleted. The second and third wells were oil discoveries in the Strawn formation and were completed in the first quarter of 2011. The horizontal well, the Spires 126-1H, came on-line in the first quarter of 2011 and produced an average of 272 Boepd (59% oil) during the first 12 days of production. The vertical well, the Spires 149-1, continues to recover load water. Our budget for 2011 currently includes the drilling of three horizontal wells targeting the Strawn formation.

Permian Basin – Shallow Howe – Yates. We currently own approximately 2,000 gross/net acres in the Howe field, located in Ward County, Texas. In 2010, we evaluated a shallow oil play targeting the Yates formation which has proven to be productive in the area. Our budget for 2011 currently includes the drilling of three vertical wells targeting the Yates formation.

Onshore Gulf Coast Basin – Portilla – Frio. We currently own approximately 1,100 gross/net acres in the Portilla field, located in San Patricio County, Texas. In 2009 and 2010, we drilled three oil in-fill development wells which proved up our concept of undrained pockets of oil between the producing wells. Our budget for 2011 currently includes the drilling of thirteen vertical wells targeting the Frio formation.

Non-Core Divestitures

In the fourth quarter of 2009 and throughout 2010, we sold certain properties, principally non-operated, non-core assets, to generate cash for debt repayment and to accelerate our drilling program. We sold properties in nine different states for combined net proceeds of approximately $32.2 million ($2.4 million in 2009 and $29.8 million in 2010, of which $8.4 million was received in February 2011) at various property auctions to numerous buyers. In total, these properties produced approximately 611 Boepd during 2009 and had 2.3 MMBoe of proved reserves as of December 31, 2009. The first $10.0 million of net proceeds was used to repay the term loan portion of our credit facility and the remaining $22.2 million was used to repay outstanding indebtedness under the revolving portion of the credit facility, for capital expenditures and general corporate purposes.

Sale of Common Stock

On February 1, 2011, we completed a public offering of 23.6 million shares of common stock (of which 8.5 million shares were sold by certain selling stockholders) at a public offering price of $4.40 per share for total net proceeds to us of approximately $62.0 million, after estimated fees and expenses. We used the net proceeds from the offering to repay indebtedness outstanding under our credit facility, to increase our 2011 capital expenditure budget and for general corporate purposes. We did not receive any proceeds from the sale of shares by the selling stockholders.

Markets and Customers

The revenue generated by our operations is highly dependent upon the prices we receive for our 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 petroleum producing countries, the actions of the Organization of Petroleum Exporting Countries and domestic regulation, legislation and policies. Decreases in the prices we receive for our 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 15 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, 2010, two purchasers accounted for approximately 20% of our oil and gas sales, and a single purchaser accounted for 11% of our oil and gas sales. We believe that there are numerous other purchasers available to buy our oil and gas and that the loss of one or both of these purchasers would not materially affect our ability to sell our 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, provincial 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 periodically changing administrative regulations.

Federal, state, provincial 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, provinces and other local authorities in which we operate properties. In addition, under federal and provincial 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, provincial, 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 provinces, states, and some counties and municipalities in which we operate, regulate one or more of the following:

- the location of wells;

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

Some provinces and states regulate the size and shape of development and spacing units or proration units for oil and gas properties. Some provinces and states allow forced pooling or unitization of tracts to facilitate exploitation while other states/provinces 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, provincial and 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 ratability of production. These laws and regulations may limit the amount of oil and gas we can produce from our wells or limit the number of wells or the locations at which our wells can be drilled. Moreover, each province and state generally imposes a production or severance tax with respect to the production and sale of oil, gas and NGLs within its jurisdiction.

Operations on Federal, Provincial 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 Office of Natural Resources Revenue, which we refer to as ONRR, (formerly Minerals Management Service). ONRR establishes the basis for royalty payments due under federal oil and gas leases through regulations issued under applicable statutory authority. State regulatory authorities establish similar standards for royalty payments due under state oil and gas leases. The basis for royalty payments established by ONRR and the state regulatory authorities is generally applicable to all federal and state oil and 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 gas industry increases our cost of doing business and, consequently, affects our profitability. Our competitors in the oil and gas industry are subject to the same regulatory requirements and restrictions that affect us.

Regulation of Transportation and Sale of Natural Gas in the United States

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 currently 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 natural 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 in the United States

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. 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 in the United States

Sales of 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 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, provincial, 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, provincial, 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

14

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, or other proppants, 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 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, the EPA has 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, require permitting of certain stationary sources, and may affect the outcome of other climate change lawsuits pending in United States federal courts in a manner unfavorable to our industry.

Although various climate change legislative measures have been under consideration by the U.S. Congress, it is not possible at this time to predict whether or when Congress may act on climate change legislation, although initiatives such as the U.S. House of Representatives' adoption of the "American Clean Energy and Security Act of 2009 ("ACESA"), also referred to as the Waxman-Markey cap-and-trade legislation, appears to be unlikely to become law in its current form. The purpose of ACESA was to control and reduce emissions of greenhouse gases in the United States. ACESA would have established an economy-wide cap on emissions of GHGs in the United States and would have required an overall reduction in GHG emissions of 17% (from 2005 levels) by 2020, and by over 80% by 2050. The net effect of ACESA would have been to impose increasing costs on the combustion of carbon-based fuels such as oil, refined petroleum products and gas. The U.S. Senate has worked on its own legislation for controlling and reducing emissions of GHGs in the United States. If the Senate adopts GHG legislation that is different from ACESA, the Senate legislation would need to be reconciled with ACESA and both chambers would be required to approve identical legislation before it could become law. Finally, some states, either individually or through multi-state regional initiatives, already have begun implementing legal measures to reduce emissions of GHGs, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs. Depending on the particular jurisdiction of our operations, we could be required to purchase and surrender allowances for GHG emissions resulting from our operations. 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 our plugging responsibility. Plugging and abandonment operations and associated reclamation of the surface production site are important components of our environmental management system. We plan accordingly for the ultimate disposition of properties that are no longer producing.

Title to Properties

As is customary in the oil and gas industry, we make only a cursory review of title to undeveloped oil and gas leases at the time we acquire them. However, before drilling commences, we require a thorough title search to be conducted, and any material defects in title are remedied prior to the time actual drilling of a well begins. To the extent title opinions or other investigations reflect title defects, we, rather than the seller/lessor of the undeveloped property, are typically obligated to cure any title defect at our expense. If we were unable to remedy or cure any title defect of a nature such that it would not be prudent to commence drilling operations on the property, we could suffer a loss of our entire investment in the property. We believe that we have good title to our 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 11, 2011, we had 74 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 web site 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, 2010, we had a total of $136.0 million of indebtedness under our credit facility which was reduced to $80.0 million, after applying the net proceeds from the equity offering that closed on February 1, 2011. 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 in general, 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 affect any of these remedies on satisfactory terms or at all.

A breach of the terms and conditions of our 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 our credit facility and to accelerate the repayment of amounts outstanding (including accrued and unpaid interest and fees). Upon a default under our 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 is 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 our credit facility to meet our capital requirements. Such a reduction could be the result of lower commodity prices and/or production, an 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 decreases for any reason, our ability to undertake exploration and development activities could be adversely affected. As a result, our ability to replace production may be limited. In addition, if the borrowing base under our credit facility is reduced, we could be required to reduce our borrowings under our 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. Based on the reserve information set forth in our reserve report as of December 31, 2010, our average annual estimated decline rate for our net proved developed producing reserves is 12% 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 49% of our total estimated proved reserves at December 31, 2010 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 adhere to our proposed drilling schedule.

Our final determination of whether to drill any scheduled or budgeted wells will be dependent on a number of factors, including:

- the availability and costs of drilling and service equipment and crews;
- economic and industry conditions at the time of drilling;
- prevailing and anticipated prices for oil and gas;
- the availability of sufficient capital resources;
- the results of our exploitation efforts;
- the acquisition, review and interpretation of seismic data; and
- our ability to obtain permits for drilling locations.

Although we have identified or budgeted for numerous drilling locations, we may not be able to drill those locations within our expected time frame or at all. In addition, our drilling schedule may vary from our expectations because of future uncertainties. For example, service equipment and crews are in very short supply in the Williston Basin. This shortage has caused service costs to escalate drastically in the basin. As a result, we will likely delay the drilling of our operated Bakken/Three Forks wells until additional services and crews are deployed to the basin and service costs return to normal, which we anticipate to occur in mid-2011.

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 is compounded by the fact that 49% of our total estimated proved reserves as of December 31, 2010 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.

The results of our drilling in unconventional formations, principally in emerging plays with limited drilling and production history using long laterals and modern completion techniques, are subject to more uncertainties than our drilling program in the more established plays and may not meet our expectations for reserves or production.

We have recently begun drilling wells in unconventional formations in several emerging plays. Part of our drilling strategy to maximize recoveries from these formations involves the drilling of long horizontal laterals and the use of modern completion techniques of multi-stage fracture stimulations that have proven to be successful in other basins. Our experience with horizontal drilling and multi-stage fracture stimulations of these formations to date, as well as the industry's drilling and production history in these formations, is limited. The ultimate success of these drilling and completion strategies and techniques will be better evaluated over time as more wells are drilled and longer term production profiles are established. In addition, based on reported decline rates in these emerging plays as well as the industry's experience in these formations, we estimate that the average monthly rates of production may decline as much as 70% during the first twelve months of production. Actual decline rates may differ significantly. Accordingly, the results of our drilling in these unconventional formations are more uncertain than drilling results in the other more established plays with longer reserve and production histories.

Our joint venture agreement with Rock Oil and other agreements that we may enter into present a number of challenges that could have a material adverse effect on our business, financial condition and results of operations.

Our joint venture agreement with Rock Oil represents an important part of our business. In addition, we may enter into other similar arrangements, some of which may be material. These arrangements typically present financial, managerial and operational challenges, including the existence of unknown potential disputes, liabilities or contingencies and may involve risks not otherwise present when exploring and developing properties directly, including, for example:

- our joint venture partners may share certain approval rights over major decisions;
- our joint venture partners may not pay their share of the joint venture's obligations, leaving us liable for their share of such obligations;
- our joint venture partners may terminate the agreements;
- we may incur liabilities as a result of an action taken by our joint venture partners;
- our joint venture partners may be in a position to take actions contrary to our instructions or requests or contrary to our policies or objectives; and
- disputes between us and our joint venture partners may result in delays, litigation or operational impasses.

The risks described above or the failure to continue our joint venture or to resolve disagreements with our joint venture partners could adversely affect our ability to transact the business that is the subject of such joint venture, which would in turn negatively affect our financial condition and results of operations.

We cannot control the activities on the properties we do not operate and are unable to ensure their proper operation and profitability.

We currently do not operate all of the properties in which we have an interest. As a result, we have limited ability to exercise influence over, and control the risks associated with, operation of these properties. The failure of an operator to adequately perform operations, an operator's breach of the applicable agreements or an operator's failure to act in our best interests could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our control, including:

- the operator could refuse to initiate exploitation or development projects and if we proceed with any of those projects, we may not receive any funding from the operator with respect to that project;
- the operator may initiate exploitation or development projects on a different schedule than we would prefer;

- the operator may propose greater capital expenditures than we wish, including expenditures to drill more wells or build more facilities on a project than we have funds for, which may mean that we cannot participate in those projects and thus, not participate in the associated revenue stream; and
- the operator may not have sufficient expertise or resources.

Any of these events could significantly and adversely affect our anticipated exploitation and development activities.

Seasonal weather conditions and other factors could adversely affect our ability to conduct drilling activities.

Our operations could be adversely affected by weather conditions and wildlife restrictions on federal leases. In the Williston Basin and in Canada, drilling and other oil and gas activities cannot be conducted as effectively during the winter months. Winter and severe weather conditions limit and may temporarily halt the ability to operate during such conditions. These constraints and the resulting shortages or high costs could delay or temporarily halt our oil and gas operations and materially increase our operating and capital costs, which could have a material adverse effect on our business, financial condition and results of operations.

The lack of availability or high cost of drilling rigs, equipment, supplies, personnel and oil field services could adversely affect our ability to execute our exploitation 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, oil field services 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. During times and in areas of increased activity, the demand for oilfield services will also likely rise, and the costs of these services will likely increase, while the quality of these services may suffer. If the lack of availability or high cost of drilling rigs, equipment, supplies, oil field services or qualified personnel were particularly severe in any of our areas of operation, we could be materially and adversely affected. Delays could also have an adverse effect on our results of operations, including the timing of the initiation of production from new wells.

Our drilling operations may be curtailed, delayed or cancelled as a result of a variety of factors that are beyond our control.

Our drilling operations are subject to a number of risks, including:

- unexpected drilling conditions;
- facility or equipment failure or accidents;
- adverse weather conditions;
- title problems;
- unusual or unexpected geological formations;
- 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 do not plan to insure against all potential operating risks. We might incur substantial losses from, and be subject to substantial liability claims for, uninsured or underinsured risks related to our oil and gas operations.

We do not intend to insure against all risks. Our oil and gas exploitation and production activities will be subject to hazards and risks associated with drilling for, producing and transporting oil and gas, and any of these risks can cause substantial losses resulting from:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater, shoreline contamination, underground migration and surface spills or mishandling of fracturing fluids, including chemical additives;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oil field drilling and service tools and casing collapse;
- leaks of gas, oil, condensate, natural gas liquids and other hydrocarbons or losses of these hydrocarbons as a result of accidents during drilling and completion operations, including hydraulic fracturing, or in the gathering and transportation of hydrocarbons, malfunctions of pipelines, measurement equipment or processing or other facilities in the Company's operations or at delivery points to third parties;
- fires and explosions;
- personal injuries and death;
- regulatory investigations and penalties; and
- natural disasters.

We might elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. Losses and liabilities arising from uninsured and underinsured events or in amounts in excess of existing insurance coverage could have a material adverse effect on our business, financial condition or results of operations.

Hydraulic fracturing, the process used for extracting oil and gas from shale and other formations, has recently come under increased scrutiny and could be the subject of further regulation that could impact the timing and cost of development.

The Underground Injection Control, or UIC, regulation promulgated under the provisions of the federal Safe Drinking Water Act, or the SDWA, exclude hydraulic fracturing from the definition of "underground injection." However, the Environmental Protection Agency, or EPA, is now re-evaluating hydraulic fracturing and the U.S. Senate and House of Representatives are currently considering bills entitled the Fracturing Responsibility and Awareness of Chemicals Act, or the FRAC Act, to amend the SDWA to repeal this exemption. If enacted, the FRAC Act would amend the definition of "underground injection" in the SDWA to encompass hydraulic fracturing activities, which could require hydraulic fracturing operations to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting, and recordkeeping obligations, and meet plugging and abandonment requirements. The FRAC Act also proposes to require the reporting and public disclosure of chemicals used in the fracturing process, which could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater.

Hydraulic fracturing is the primary production method used to extract reserves located in many of the unconventional oil and gas plays in the United States and Canada. Depending on the legislation that may ultimately be enacted or the regulations that may be adopted at the federal, state and/or provincial levels, exploration, exploitation and production activities that entail hydraulic fracturing could be subject to additional regulation and permitting requirements. Individually or collectively, such new legislation or regulation could lead to operational delays or increased operating costs and could result in additional burdens that could increase the costs and delay the development of unconventional oil and gas resources from formations which are not commercial without the use of hydraulic fracturing. This could have an adverse effect on our business, 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;
- 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 our assets.

In addition, our credit facility requires us to maintain compliance with specified financial covenants. Our ability to comply with these covenants may be adversely affected by events beyond our control, and we cannot assure you that we can maintain compliance with these covenants. These financial covenants could limit our ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary or desirable business activities.

A breach of any of these covenants could result in a default under our 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 oil and 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, as well as Canadian provincial, regulation of oil and gas production and transportation, general economic conditions and changes in supply and demand. These factors and the availability of markets are beyond our control. If our access to these transportation options dramatically changes, the financial impact on us could be substantial and adversely affect our ability to produce and market our oil and gas.

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

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

During 2010, differentials averaged ($8.14) per Bbl of oil and ($0.41) per Mcf of gas. Approximately 27% of our production during 2010 was from the Rocky Mountain region. Historically, this region has experienced wider differentials than our Permian Basin and Gulf Coast properties. As the percentage of our production from the Rocky Mountain region increases, we expect that our price differentials will also increase. Increases in the differential between the benchmark prices for oil and gas and the wellhead price we receive could significantly reduce our revenues and our cash flow from operations.

Our derivative contracts could result in financial losses or could reduce our cash flow.

To achieve more predictable cash flow and reduce our exposure to adverse fluctuations in the prices of oil and gas and to comply with the requirements under our credit facility, we enter into derivative contracts, which we sometimes refer to as hedging arrangements, for a significant portion of our oil and gas production that could result in both realized and unrealized derivative contract losses. We have entered into NYMEX-based fixed price commodity swap arrangements on approximately 80% of the oil and gas production from our estimated net proved developed producing reserves (as of December 31, 2010) through December 31, 2012 and 67% for 2013. Any new hedging arrangements will be priced at then-current market prices and may be significantly lower than the commodity swaps we currently have in place. The extent of our commodity price exposure will be related largely to the effectiveness and scope of our commodity price derivative contracts. For example, the prices utilized in our derivative contracts are currently NYMEX-based, which may differ significantly from the actual prices we receive for oil and gas which are based on the local markets where the oil and gas is produced. The prices that we receive for our oil and gas production are typically lower than the relevant benchmark prices that are used for calculating commodity derivative positions. The difference between the benchmark price and the price we receive is called a differential, a significant portion of which is based on the delivery location which is called the basis differential. As a result, our cash flow from operations could be affected if the basis differentials widen more than we anticipate. For more information see "—An increase in the differential between NYMEX and the reference or regional index price used to price our oil and gas would reduce our cash flow from operations." We currently do not have any basis differential hedging arrangements in place. Our cash flow from operations could also be affected based upon the levels of our production. If production is higher than we estimate, we will have greater commodity price exposure than we intended. If production is lower than the nominal amount that is subject to our hedging arrangements, we may be forced to satisfy all or a portion of our hedging arrangements without the benefit of the cash flow from our sale of the underlying physical commodity, resulting in a substantial reduction in cash flows.

If the prices at which we hedge our oil and gas production are less than current market prices, our cash flow from operations could be adversely affected.

When our derivative contract prices are higher than market prices, we will incur realized and unrealized gains on our derivative contracts and conversely, when our contract prices are lower than market prices, we will incur realized and unrealized losses. On July 29, 2009, we entered into hedging arrangements for specified volumes, which equated to approximately 80% of the estimated oil and gas production from our proved developed producing reserves (as of December 31, 2010) through December 31, 2012 and 67% for 2013 after unwinding our previous hedging arrangements. For the year ended December 31, 2010, we recognized a realized gain on oil and gas derivative contracts of $2.8 million and an unrealized gain of $11.4 million. The realized gains resulted in an increase in cash flow from operations. We expect to continue to enter into similar hedging arrangements in the future to reduce our cash flow volatility.

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

- highly volatile oil and gas prices;
- our production being less than expected; or
- a counterparty to one of our hedging transactions defaulting on its contractual obligations.

The counterparties to our derivative contracts may be unable to perform their obligations to us which could adversely affect our cash flow.

At times when market prices are lower than our derivative contract prices, we are entitled to cash payments from the counterparties to our derivative contracts. Any number of factors may adversely affect the ability of our counterparties to fulfill their contractual obligations to us. If one of our counterparties is unable or unwilling to make the required payments to us, it could adversely affect our cash flow.

Potential regulations under the Dodd-Frank Act regarding derivatives could adversely impact our ability to engage in commodity price risk management activities.

We have entered into commodity derivative contracts in order to hedge a portion of our production. On July 21, 2010, Congress enacted the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, which imposes a comprehensive regulatory scheme significantly impacting companies engaged in over-the-counter swap transactions. The Dodd-Frank Act generally applies to "swaps" entered into by "major swap participants" and/or "swap dealers," each as defined in the Dodd-Frank Act. A swap is very broadly defined in the Dodd-Frank Act and includes an energy commodity swap. A swap dealer includes an entity that regularly enters into swaps with counterparties as an "ordinary course of business for its own account." Furthermore, a person may qualify as a major swap participant if it maintains a "substantial position" in outstanding swaps, other than swaps used for "hedging or mitigating commercial risk" or whose positions create substantial exposure to its counterparties or the U.S. financial system. The Dodd-Frank Act subjects swap dealers and major swap participants to substantial supervision and regulation by the Commodity Futures Trading Commission, or the CFTC, including capital standards, margin requirements, business conduct standards, and recordkeeping and reporting requirements. It also requires most regulated swaps to be cleared through a derivatives clearing organization, or DCO, registered with the CFTC. By clearing through a DCO, each party to a swap will be required to provide collateral to the DCO to settle, on a daily basis, any credit exposure resulting from fluctuations in market prices. The CFTC also has the authority to impose position limits on companies trading in OTC derivatives markets. Although the Dodd-Frank Act provides a framework for regulating OTC swap transactions, the substance of the Dodd-Frank Act will be set forth in numerous rules subsequently promulgated by the CFTC and other agencies. Because the CFTC has not yet clearly articulated the scope of key definitions in the Dodd-Frank Act, such as "swap," "swap dealer" and "major swap participant," and because the parameters of Dodd-Frank Act requirements are still shifting, it is impossible to know exactly how the Dodd-Frank Act will impact our business. However, the issuance of any rules or regulations relating to the Dodd-Frank Act that subject us to additional business conduct standards, position limits and/or reporting, capital, margin or clearing requirements with respect to our commodity swap risk management positions could have an adverse effect on our ability to hedge risks associated with our business or on the cost of our hedging activities. If we are required to post additional collateral as a result of new rules, we would have to do so by utilizing cash or letters of credit, which would reduce our liquidity position and increase costs. These changes could materially reduce our hedging opportunities and increase the costs associated with our hedging programs, both of which could negatively affect our cash flow.

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

We use the full cost method to account for our oil and gas operations. Accordingly, we capitalize the cost to acquire, explore for and develop our oil and gas properties. Under full cost accounting rules, the net capitalized cost of our oil and gas properties may not exceed a "ceiling limit" which is based upon the present value of estimated future net cash flows from our proved reserves, discounted at 10%. If the net capitalized costs of our oil and gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling limitation write-down." This charge does not impact cash flow from operating activities, but it does reduce our stockholders' equity and earnings. The risk that we will be required to write-down the carrying value of our oil and gas properties increases when oil and gas prices are low, which could be further impacted by the SEC's modernized oil and gas reporting disclosures, which require us to use an average price over the prior 12-month period, rather than the year-end price, when calculating the PV-10. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves. An expense recorded in one period may not be reversed in a subsequent period even though oil and gas prices may have increased the ceiling applicable in the subsequent period.

At December 31, 2010, the net capitalized costs of our United States oil and gas properties did not exceed the present value of our estimated proved reserves; however, the net capitalized costs of our Canadian oil and gas properties exceeded the present value of our estimated proved reserves by approximately $4.8 million, resulting in a write down of $4.8 million. At December 31, 2009, the net capitalized cost of our oil and gas properties did not exceed the present value of our estimated proved reserves. At December 31, 2008, the net capitalized costs of our oil and gas properties exceeded the present value of our estimated proved reserves by $116.4 million, resulting in a write down of $116.4 million. We cannot assure you that we will not experience additional write downs in the future.

Use of our net operating loss carryforwards may be limited.

At December 31, 2010, we had, subject to the limitation discussed below, $141.8 million of net operating loss carryforwards for U.S. tax purposes and $1.1 million for Canadian tax purposes. The U.S. loss carryforwards will expire in varying amounts through 2030, and the Canadian carryforward will expire in 2030, if not otherwise used.

The use of our net operating loss carryforwards may be limited if an "ownership change" of over 50 percentage points occurs during any three-year period. Based on current estimates, we believe that we have not surpassed this threshold. It is feasible that even a modest change of ownership (including, but not limited to, a shift in common stock ownership by one reasonably large stockholder or any offering of common stock to a limited number of investors) during the three-year period following the merger with the Partnership, which was consummated on October 5, 2009, could trigger a significant limitation of the amount of such net operating loss carryforwards available to offset future taxable income.

Additionally, uncertainties exist as to the future utilization of the operating loss carryforwards. Therefore, in accordance with Financial Accounting Standards Board ("FASB") and Accounting Standards Codification ("ASC") 740-10, we have established a valuation allowance of $60.8 million for deferred tax assets at December 31, 2008, $91.5 million at December 31, 2009 and $91.9 million at December 31, 2010.

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

Our financial statements are complex and our control environment cannot completely prevent fraud or human error.

Due to the nature of our business, and accounting principles generally accepted in the United States of America, our financial statements are complex, particularly with reference to derivative contracts, asset retirement obligations, deferred taxes and the accounting for our stock-based compensation plans. We expect such complexity to continue and possibly increase. Because of these complexities, many of our accounting processes are done manually and are dependent upon individual data input or review. While we continue to automate our processes and enhance our review and put in place controls to reduce the likelihood for errors, we expect that for the foreseeable future many of our processes will remain manually intensive and thus subject to human error.

A control environment, no matter how well conceived and operated, can provide only reasonable assurance that the objectives of the control environment are met. Because of the inherent limitations in all control environments, no evaluation of controls can provide absolute assurance that all control issues have been detected and misstatements due to error or fraud may occur and not be detected.

Risks Related to Our Industry

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

Our revenue, cash flows, profitability and future rate of growth depend substantially upon prevailing prices for oil and gas. Gas prices have affected us more than oil prices because 64% of our production during 2010 and 58% of our proved reserves at December 31, 2010 were gas. Prices also affect the amount of cash flow available for capital expenditures and our ability to borrow money or raise additional capital. Lower prices may also make it uneconomical for us to increase or even continue current production levels of oil and gas.

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

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

- political stability and economic conditions in oil producing countries, particularly in the Middle East;
- weather conditions;
- price and level of foreign imports;
- terrorist activity;
- availability of pipeline and other secondary capacity;
- general economic conditions;

- domestic and foreign governmental regulation; and
- the price and availability of alternative fuel sources.

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

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

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

The estimates of our reserves as of December 31, 2010 are based upon various assumptions about future production levels, prices and costs that may not prove to be correct over time. In particular, estimates of oil and gas reserves, future net revenue from proved reserves and the PV-10 thereof for our oil and gas properties are based on the assumption that future oil and gas prices remain the same as the twelve month first-day-of-the-month average oil and gas prices for the year ended December 31, 2010. The average realized sales prices as of such date used for purposes of such estimates were $3.91 per Mcf of gas and $70.72 per Bbl of oil. The December 31, 2010 estimates also assume that we will make future capital expenditures of approximately $164.1 million in the aggregate primarily from 2011 through 2015, which are necessary to develop and realize the value of proved reserves on our properties. In addition, approximately 49% of our total estimated proved reserves as of December 31, 2010 were classified as 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 our reserves set forth or incorporated by reference in this document.

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 based the estimated discounted future net cash flows from our proved reserves as of December 31, 2010 on the twelve month first-day-of-the-month average oil and gas prices for the year ended December 31, 2010 and costs in effect on December 31, 2010, 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 our oil and gas;
- actual prices we receive for our oil and gas;
- our actual operating costs;
- the amount and timing of our capital expenditures;
- the amount and timing of our actual production; and

- changes in governmental regulations or taxation.

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

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

Our oil and gas drilling and production activities are subject to numerous risks, many of which are beyond our control. These risks include the risk of fire, explosions, blow-outs, pipe failure, abnormally pressured formations and environmental hazards. Environmental hazards include oil spills, gas leaks, ruptures, discharges of toxic gases, underground migration and surface spills or mishandling of fracture fluids, including chemical additives. 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, environmental damage, regulatory investigation and penalties and suspension of operations. In accordance with industry practice, we maintain insurance against some, but not all, of the risks described above. We cannot assure you that our insurance will be adequate to cover losses or liabilities. Also, we cannot predict the continued availability of insurance at premium levels that justify its purchase.

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

We operate in a highly competitive environment. The principal resources necessary for the exploration and production of oil and gas are leasehold prospects under which oil and gas reserves may be discovered, drilling rigs and related equipment to explore for such reserves and knowledgeable personnel to conduct all phases of 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, we cannot assure you that such resources will be available to us in the future.

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

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

Proposed federal legislation concerning tax deductions currently available with respect to oil and gas drilling may adversely affect our net earnings.

The Obama administration has proposed the outright elimination of many of the key federal income tax benefits historically associated with the oil and gas industry. Although presented in very summary form, among other significant energy tax items, the administration's budget appears to propose the complete elimination of (i) expensing of intangible drilling costs, and (ii) the "percentage depletion" method of deduction with respect to oil and gas wells. Although no legislation has been formally introduced, if this proposal (or others) is enacted into law, it could adversely affect our net earnings.

Possible regulation related to global warming and climate change could have an adverse effect on our operations and demand for oil and gas.

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, governments have begun adopting domestic and international climate change regulations that requires reporting and reductions of the emission of greenhouse gases. Methane, a primary component of natural gas, and carbon dioxide, a by-product of the burning of oil, gas and refined petroleum products, are considered greenhouse gases. Internationally, the United Nations Framework Convention on Climate Change and the Kyoto Protocol address greenhouse gas emissions, and several countries including the European Union have established greenhouse gas regulatory systems. In the United States, at the state level, many states, either individually or through multi-state regional initiatives, have begun implementing legal measures to reduce emissions of greenhouse gases, primarily through the planned development of emission inventories or regional greenhouse gas cap and trade programs or have begun considering adopting greenhouse gas regulatory programs. At the federal level, in June 2009, the United States House of Representatives passed the American Clean Energy and Security Act of 2009, also known as the Waxman-Markey Bill or ACESA. The United States Senate passed out of committee the Clean Energy Jobs and American Power Act, also known as the Kerry-Boxer Bill. Although these bills differ in certain ways, they both contain provisions that would establish a cap and trade system for restricting greenhouse gas emissions in the United States. Under such a system, certain sources of greenhouse gas emissions would be required to obtain greenhouse gas emission “allowances” corresponding to their annual emissions of greenhouse gases. The number of emission allowances issued each year would decline as necessary to meet overall emission reduction goals. As the number of greenhouse gas emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. The ultimate outcome of this federal legislative initiative remains uncertain.

In addition to pending climate legislation, the EPA has issued greenhouse gas monitoring and reporting regulations that went into effect January 1, 2010, and require reporting by regulated facilities by March 2011 and annually thereafter. Beyond measuring and reporting, the EPA issued an “Endangerment Finding” under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The finding serves as a first step to issuing regulations that would require permits for and reductions in greenhouse gas emissions for certain facilities. The EPA has proposed such greenhouse gas regulations and may issue final rules this year.

In the courts, several decisions have been issued that may increase the risk of claims being filed by government entities and private parties against companies that have significant greenhouse gas emissions. Such cases may seek to challenge air emissions permits that greenhouse gas emitters apply for and seek to force emitters to reduce their emissions or seek damages for alleged climate change impacts to the environment, people, and property.

Any laws or regulations that may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur increased operating and compliance costs, and could have an adverse effect on demand for the oil and gas that we produce and as a result, our financial condition and results of operations could be adversely affected.

Risks Related to Our Common Stock

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

We are currently authorized to issue 200,000,000 shares of common stock with such rights as determined by our board of directors. We may in the future issue previously authorized and unissued securities, resulting in the dilution of the ownership interests of current stockholders. The potential issuance of any such additional shares of common stock may create downward pressure on the trading price of our common stock. We may also issue additional shares of common stock or other securities that are convertible into or exercisable for common stock for capital raising or other business purposes. Future sales of substantial amounts of common stock, or the perception that sales could occur, could have a material adverse effect on the price of our common stock.

We will not pay dividends on our common stock for the foreseeable future.

We currently anticipate that we will retain all future earnings, if any, to finance the growth and development of our business. We do not intend to pay cash dividends in the foreseeable future. In addition, our credit facility prohibits us from paying dividends and making other distributions.

Shares eligible for future sale may depress our stock price.

At December 31, 2010, we had 76,427,561 shares of common stock outstanding of which 6,089,883 shares were held by affiliates and, in addition, 4,820,450 shares of common stock were subject to outstanding options granted under stock option plans (of which 2,288,213 shares were vested at December 31, 2010).

All of the shares of common stock held by affiliates are restricted or are control securities under Rule 144 promulgated under the Securities Act. The shares of common stock issuable upon exercise of 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 our common stock and could impair our ability to raise additional capital through the sale of equity securities.

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

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

- fluctuations in commodity prices;
- variations in results of operations;
- legislative or regulatory changes;
- general trends in the oil and gas industry;
- sales of common stock or other actions by our stockholders;
- additions or departures of key management personnel;
- commencement of or involvement in litigation;
- speculation in the press or investment community regarding our business;
- an inability to maintain the listing of our common stock on a national securities exchange;
- market conditions; and
- analysts' estimates and other events in the oil and gas industry.

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

Subject to the rules of The NASDAQ Stock Market, our articles of incorporation authorize our board of directors to issue one or more series of preferred stock and set the terms of the preferred stock without seeking any further approval from holders of our common stock. Any preferred stock that is issued may rank ahead of our common stock in terms of dividends, priority and liquidation premiums and may have greater voting rights than our common stock. On March 16, 2010, our board of directors adopted a tax benefits preservation plan and declared a dividend of one preferred share purchase right for each outstanding share of our common stock. These rights are only activated if the plan is triggered by any person or group acquiring 4.9% or more of our outstanding common stock without our approval.

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

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

March 16, 2010, our board of directors adopted a tax benefits preservation plan designed to preserve our substantial tax assets. In addition, the plan is intended to act as a deterrent to any person or group acquiring 4.9% or more of our outstanding common stock without our approval.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Exploratory and Developmental Acreage

Our principal oil and gas properties consist of producing and non-producing oil and gas leases, including reserves of oil and gas in place. The following table sets forth our developed and undeveloped acreage and fee mineral acreage as of December 31, 2010. There are no material lease expirations in 2011.

	Developed Acreage		Undeveloped Acreage		Fee Mineral Acreage (1)		
	Gross Acres	Net Acres	Gross Acres	Net Acres	Gross Acres	Net Acres	Total Net Acres (2)
Rocky Mountain	61,238	31,309	72,358	49,521	1,400	1,160	81,990
Mid-Continent	23,840	5,580	240	120	543	69	5,769
Permian Basin	24,054	17,322	17,977	16,357	12,007	5,272	38,951
Onshore Gulf Coast	5,801	5,173	2,951	2,603	—	—	7,776
Total United States	114,933	59,384	93,526	68,601	13,950	6,501	134,486
Alberta, Canada	320	320	8,800	8,800	—	—	9,120
Total	115,253	59,704	102,326	77,401	13,950	6,501	143,606

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

(2) Includes 3,981 acres in the Permian Basin region that are included in developed and undeveloped gross acres, but does not include net acres owned by Blue Eagle in the onshore Gulf Coast region.

Productive Wells

The following table sets forth our gross and net productive wells, expressed separately for oil and gas, as of December 31, 2010:

	Productive Wells			
	Oil		Gas (1)	
	Gross	Net	Gross	Net
Rocky Mountain	391.0	88.2	505.0	16.0
Mid-Continent	6.0	3.5	141.0	29.8
Permian Basin	154.0	128.3	56.0	28.1
Onshore Gulf Coast	28.5	26.6	24.5	20.0
Total United States	579.5	246.6	726.5	93.9
Alberta, Canada	1.0	1.0	—	—
Total	580.5	247.6	726.5	93.9

(1) Excludes 1.0 gross (1.0 net) wells owned by Blue Eagle.

Reserves Information

In December 2009, we adopted revised oil and gas reserve estimation and disclosure requirements which conforms the definition of proved reserves with the Modernization of Oil and Gas Reporting rules, which were issued by the SEC at the end of 2008. The new accounting standard requires that the average, first-day-of-the-month price during the 12-month period preceding the end of the year be used when estimating reserve quantities and permits the use of reliable technologies to determine proved reserves, if those technologies have been demonstrated to result in reliable conclusions about reserves volumes.

For the year ended December 31, 2010, DeGolyer and MacNaughton, of Dallas, Texas estimated reserves for properties comprising approximately 96% of the PV-10 of our proved oil and gas reserves. Proved reserves for the remaining 4% of our properties were estimated by Abraxas personnel because we determined that it was not practical for DeGolyer and MacNaughton to prepare reserve estimates for all of our properties because we own a large number of properties with relatively low values. DeGolyer and MacNaughton's reserve report as of December 31, 2010 included a total of 648 properties, which comprised approximately 96% of the PV-10 of all our properties as of that date. A total of 520 properties were included in the reserve estimates prepared by Abraxas personnel which comprised approximately 4% of our PV-10 at December 31, 2010.

The technical personnel responsible for preparing the reserve estimates at DeGolyer and MacNaughton meet the requirements regarding qualifications, independence, objectivity, and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. DeGolyer and MacNaughton is an independent firm of petroleum engineers, geologists, geophysicists, and petrophysicists; they do not own an interest in any of our properties and are not employed on a contingent fee basis. All reports by DeGolyer and

MacNaughton were developed utilizing geological and engineering data provided by Abraxas. The report of DeGolyer and MacNaughton dated February 22, 2011, which contains further discussions of the reserve estimates and evaluations prepared by DeGolyer and MacNaughton as well as the qualifications of DeGolyer and MacNaughton's technical personnel responsible for overseeing such estimates and evaluations is attached as Exhibit 99.1 to this report.

Estimates of reserves at December 31, 2010 were based on studies performed by the operations department of Abraxas which is directly responsible for Abraxas' reserve evaluation process. The Vice President of Operations is the manager of this department and is the primary technical person responsible for this process. The Vice President of Operations holds a Bachelor of Science degree in Petroleum Engineering, and has 25 years of experience in reserve evaluations. The operations department consists of four petroleum engineers with Bachelor degrees in Petroleum Engineering, one of whom is a Registered Professional Engineer in the State of Texas, and various other technical professionals. Reserve information as well as models used to estimate such reserves are stored on secured databases. Non-technical inputs used in reserve estimation models, including oil and gas prices, production costs, future capital expenditures and Abraxas' net ownership percentages are obtained from other departments within Abraxas.

Oil and gas reserves and the estimates of the present value of future net revenues therefrom were determined based on prices and costs as prescribed by SEC and FASB guidelines. Reserve calculations involve the estimate of future net recoverable reserves of oil and gas 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 oil and 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. Proved reserves were estimated in accordance with guidelines established by the 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. For the year ended December 31, 2010, commodity prices over the prior 12-month period and year end costs were used in estimating net cash flows.

In addition to proved reserves, we disclose our "probable" and "possible" reserves in this report. Probable reserves are those additional reserves that are less likely to be recovered than proved reserves. Possible reserves are those additional reserves that are less likely to be recoverable than probable reserves. These estimates of probable and possible reserves are by their very nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being actually realized by us.

The following table sets forth certain information regarding estimates of our oil and gas reserves as of December 31, 2010, which excludes reserves attributable to our equity interest in Blue Eagle. All of our reserves are located in the United States and Canada.

Summary of Oil and Gas Reserves
As of December 31, 2010

Reserve Category	Oil (MBbls)	Gas (MMcf)
Proved		
Developed	5,862	42,750
Undeveloped	3,932	42,163
Total Proved	9,794	84,913
Probable		
Developed	183	1,302
Undeveloped	7,145	36,192
Possible		

Developed	—	—
Undeveloped	7,274	14,032

The process of estimating oil and gas reserves is complex and involves decisions and assumptions in evaluating the available geological, geophysical, engineering and economic data. Accordingly, these estimates are imprecise. Actual future production, oil and gas prices, revenues, taxes, capital expenditures, operating expenses and quantities of recoverable oil and gas reserves most likely will vary from those estimated. Any significant variance could materially affect the estimated quantities and present value of our reserves set forth or incorporated by reference in this document. We may also adjust estimates of reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control. In particular, estimates of oil and gas reserves, future net revenue from reserves and the PV-10 thereof for the oil and gas properties described in this report are based on the assumption that future oil and gas prices remain the same as oil and gas prices utilized in the December 31, 2010 report. The average realized sales prices used for purposes of such estimates were $70.72 per Bbl of oil and $3.91 per Mcf of gas. It is also assumed that we will make future capital expenditures of approximately $164.1 million in the aggregate primarily in the years 2011 through 2015, which are necessary to develop and realize the value of proved 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.

You should not assume that the present value of future net revenues referred to in this Annual Report on Form 10-K is the current market value of our estimated oil and gas reserves. In accordance with SEC requirements, the estimated discounted future net cash flows from proved reserves is calculated using the average price over the prior 12-month period. Costs used in the estimated discounted future net cash flows are costs as of the end of the period. Because we use the full cost method to account for our oil and gas 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. As of December 31, 2010, the Company's net capitalized costs of oil and gas properties in the United States did not exceed the present value of our estimated proved reserves; however, the net capitalized cost of our oil and gas properties in Canada exceeded the present value of its estimated proved reserves by $4.8 million, resulting in a write down of $4.8 million. We cannot assure you that we will not experience additional write downs in the future. Based on managements' review of average first-day-of-the-month prices for the twelve months of April 2010 through March 2011, we do not anticipate a write down at the end of the first quarter of 2011.

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 used in the estimate. Any changes in consumption by 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 oil and gas 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. Our effective interest rate on borrowings at various times and the risks associated with us or the oil and gas industry in general will affect the accuracy of the 10% discount factor.

We file reports of our estimated oil and gas 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.

Proved Undeveloped Reserves

At December 31, 2010, we had 10,959 MBoe of proved undeveloped reserves. During 2010, 214 MBoe of proved undeveloped reserves were converted to proved producing reserves. During 2010, 2,083 MBoe were added to proved undeveloped reserves, principally in the Rocky Mountain region. During 2010, 1,317 MBoe were removed from proved undeveloped reserves, in part as a result of drilling one dry hole in the onshore Gulf Coast region. The proved undeveloped reserves associated with that well (368 Boe as of December 31, 2009) were removed from our December

31, 2010 reserve report. In addition, another well and an offset location to a previously drilled well in a nearby prospect, in the onshore Gulf Coast region, were deemed marginal and uneconomic and the associated reserves (a total of 436 Boe as of December 31, 2009) were removed from our December 31, 2010 reserve report. The remaining proved undeveloped reserves that were removed from our December 31, 2010 reserve report were predominately attributable to unit wells that were successfully drilled with the associated reserves being re-allocated to the proved developed category of the respective unit. We do not have any material proved undeveloped reserves which have remained undeveloped for five or more years since the reserves were included in our reserve report.

During 2010, we spent $36.5 million on capital expenditure projects, of which $12.2 million was used to convert proved undeveloped reserves to proved developed reserves. The remaining capital expenditures ($24.3 million) during 2010 were used to develop probable, possible and incremental reserves, acquire acreage and perform workovers and recompletions across our core operating areas.

Reconciliation of Standardized Measure to PV-10

PV-10 is the estimated present value of the future net revenues from our proved oil and gas reserves before income taxes discounted using a 10% discount rate. PV-10 is considered a non-GAAP financial measure under SEC regulations because it does not include the effects of future income taxes, as is required in computing the standardized measure of discounted future net cash flows. We believe that PV-10 is an important measure that can be used to evaluate the relative significance of our oil and gas properties and that PV-10 is widely used by securities analysts and investors when evaluating oil and gas companies. Because many factors that are unique to each individual company impact the amount of future income taxes to be paid, the use of a pre-tax measure provides greater comparability of assets when evaluating companies. We believe that most other companies in the oil and gas industry calculate PV-10 on the same basis. PV-10 is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting income taxes.

Due to our loss carry forwards and the tax basis of our properties, there is no impact of income taxes on our standardized measure calculation. As a result, there is currently no difference between the standardized measure of our oil and gas reserves, which is a GAAP financial measure, and the PV-10 of our reserves.

Blue Eagle Reserve Data

The following table sets forth certain information attributable to our 50% equity interest in the estimates of Blue Eagle's oil and gas reserves as of December 31, 2010. All of Blue Eagle's reserves are located in the United States.

Summary of Oil and Gas Reserves – Blue Eagle
As of December 31, 2010

Reserve Category	Oil (MBbls)	Gas (MMcf)
Proved		
Developed	—	—
Undeveloped	1,239	8,301
Total Proved	1,239	8,301
Probable		
Developed	—	—
Undeveloped	737	4,933
Possible		
Developed	—	—
Undeveloped	—	—

The following table sets forth certain information regarding the combined reserves of Abraxas and Blue Eagle as of December 31, 2010.

Summary of Oil and Gas Reserves – Combined
As of December 31, 2010

Reserve Category	Oil (MBbls)	Gas (MMcf)
Proved		

Developed	5,862	42,750
Undeveloped	5,171	50,464
Total Proved	11,033	93,214
Probable		
Developed	183	1,302
Undeveloped	7,882	41,125
Possible		
Developed	—	—
Undeveloped	7,274	14,032

Oil and Gas Production, Sales Prices and Production Costs

The following table presents our net oil and gas production, the average sales price per Bbl of oil and per Mcf of gas produced and the average cost of production per Boe of production sold, for the three years ended December 31, 2010:

	2008	2009	2010
Oil production (Bbls)			
Rocky Mountain	310,820	332,867	290,342
Permian Basin	109,922	117,555	108,040
Onshore Gulf Coast	91,791	82,004	75,649
Other (4)	37,354	46,358	34,886
Total	549,887	578,784	508,917
Gas production (Mcf)			
Rocky Mountain	559,990	611,714	570,736
Permian Basin	2,628,246	2,297,465	2,135,918
Onshore Gulf Coast	2,006,268	2,119,413	1,757,901
Other (4)	1,148,430	1,300,6224	1,014,347
Total	6,342,934	6,329,216	5,478,902
Total production (MBoe) (1)	1,607	1,634	1,422
Average sales price per Bbl of oil (2)			
Rocky Mountain	$ 89.52	$ 56.07	$ 68.40
Permian Basin	$ 94.41	$ 56.86	$ 75.83
Onshore Gulf Coast	$ 99.57	$ 57.41	$ 77.28
Other (4)	$ 96.69	$ 56.44	$ 69.37
Composite	$ 92.66	$ 54.15	$ 71.37
Average sales price per Mcf of gas (2)			
Rocky Mountain	$ 7.03	$ 3.50	$ 4.28
Permian Basin	$ 7.22	$ 3.21	$ 4.00
Onshore Gulf Coast	$ 7.42	$ 3.06	$ 3.62
Other (4)	$ 7.42	$ 3.21	$ 4.32
Composite	$ 7.59	$ 3.24	$ 3.97
Average sales price per Boe (2)	$ 61.66	$ 31.73	$ 40.82
Average cost of production per Boe produced (3)			
Rocky Mountain	$ 16.98	$ 18.00	$ 17.34
Permian Basin	$ 7.22	$ 11.52	$ 11.88
Onshore Gulf Coast	$ 5.94	$ 5.64	$ 6.06
Other (4)	$ 9.06	$ 10.86	$ 9.36
Composite	$ 10.91	$ 12.50	$ 13.81

(1) Oil and gas were combined by converting gas to a Boe equivalent on the basis 6 Mcf of gas to 1 Bbl of oil.

(2) Before the impact of hedging activities.

(3) Production costs include direct lease operating costs but exclude ad valorem taxes and production taxes.

(4) Includes Canada and Mid-Continent comprising approximately 6% of total proved reserves.

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, 2010:

	2008		2009		2010 (1)	
	Gross	Net	Gross	Net	Gross	Net
Exploratory						
Productive						
Rocky Mountain	-	-	-	-	1.0	1.0
Permian Basin	-	-	1.0	1.0	1.0	0.4
Onshore Gulf Coast	1.0	0.6	-	-	-	-
Other (2)	-	-	-	-	-	-
Total	1.0	0.6	1.0	1.0	2.0	1.4
Non-productive			-	-		
Onshore Gulf Coast	-	-	-	-	1.0	1.0
Total	-	-	-	-	1.0	1.0
Development						
Productive						
Rocky Mountain	34.0	1.7	9.0	1.1	16.0	1.8
Permian Basin	7.0	6.0	3.0	0.1	2.0	2.0
Onshore Gulf Coast	2.0	1.5	–	–	3.0	3.0
Other (2)	6.0	0.2	2.0	0.1	3.0	2.0
Total	49.0	9.4	14.0	1.3	24.0	8.8
Non-productive						
Onshore Gulf Coast	-	-	1.0	1.0	-	-
Total	-–	- –	1.0	1.0	-	-

(1) Excludes 1.0 gross (1.0 net) gas well owned by Blue Eagle.

(2) Includes Canada and Mid-Continent comprising approximately 6% of total proved reserves.

Present Activities

As of March 11, 2011, we had two operated wells and nine non-operated wells in process of drilling and/or completing. The following provides an overview of our present activities by region:

Operational Update

Rocky Mountain:

- In McKenzie County, North Dakota, we drilled the Stenehjem 27-34 1H to a total measured depth of 16,504 feet, including a 5,965 foot lateral in the middle Bakken formation. A 20-stage fracture stimulation is tentatively scheduled for the second quarter of 2011. We own an approximate 79% working interest in this well.

- In Dunn and McKenzie Counties, North Dakota and Richland County, Montana, we participated in six non-operated horizontal wells, targeting the middle Bakken or Three Forks formation, which are currently drilling, completing or waiting on completion. Our working interest ranges from 1.8% to 6.5% in each of these wells.

- In McKenzie County, North Dakota, we participated in one non-operated horizontal well targeting the Mission Canyon formation, which is currently drilling. We own a 2.9% working interest in this well.

- In Bowman County, North Dakota, we participated in one non-operated horizontal air injection well targeting the Red River formation, which is currently drilling. We own a 4.0% working interest in this well.

Gulf Coast:

- In DeWitt County, Texas, Blue Eagle, is participating in one non-operated horizontal well, targeting the Eagle Ford formation, which is currently drilling. Blue Eagle owns a 43.9% working interest in this well and we currently own an approximate 50% equity interest in Blue Eagle.

- In San Patricio County, Texas, we are currently drilling the first well in a multi-well drilling program targeting the Frio sands at depths of 7,400 and 8,100 feet. We own a 100% working interest in each of these wells.

Office Facilities

Our executive and administrative offices are located at 18803 Meisner Drive, San Antonio, Texas 78258, and consist of approximately 21,000 square feet. We own the building which is subject to a real estate lien note. The note bears interest at a fixed rate of 6.375%, and is payable in monthly installments of principal and interest of $39,754 based on a twenty year amortization. The note matures in May 2015 at which time the outstanding balance becomes due. The note is secured by a first lien deed of trust on the property and improvements. As of December 31, 2010, $5.1 million was outstanding on the note. We lease office space in Calgary, Alberta for a monthly rental of $3,836 CN. The lease expires on January 31, 2014.

Other Properties

We own 10 acres of land, an office building, workshop, warehouse and house in Sinton, Texas, 603 acres of land and an office building in Scurry County, Texas, 50 acres of land in Lavaca County, Texas, 160 acres of land in Coke County, Texas, 600 acres of land in McKenzie County, North Dakota and 12,177 acres of land in Pecos County, Texas. We 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 our operations in the normal course of business. At December 31, 2010, 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. [Removed and Reserved]

Part II

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

Market Information

Our common stock is traded on The NASDAQ Stock Market under the symbol "AXAS." The following table sets forth certain information as to the high and low sales price quoted for our common stock on The NASDAQ.

Period		High	Low
2009			
	First Quarter	$1.50	$0.74
	Second Quarter	1.39	0.85
	Third Quarter	1.88	0.86
	Fourth Quarter	2.55	1.55
2010			
	First Quarter	$2.50	$1.78
	Second Quarter	3.16	1.89
	Third Quarter	3.14	2.30
	Fourth Quarter	4.69	2.69
2011	First Quarter (Through March 11, 2011)	$6.16	$4.06

Holders

As of March 11, 2011, we had 91,561,792 shares of common stock outstanding and approximately 1,192 stockholders of record.

Dividends

We have not paid any cash dividends on our common stock and it is not presently determinable when, if ever, we will pay cash dividends in the future. In addition, our credit facility prohibits the payment of cash dividends on our common stock.

Performance Graph

Set forth below is a performance graph comparing yearly cumulative total stockholder return on our common stock with (a) the monthly index of stocks included in the Standard and Poor's 500 Index and (b) the Small Cap Index of stocks of oil and gas exploration and production companies with a market capitalization of less than $1.2 billion (the "Comparable Companies"). The Comparable Companies are: Double Eagle Petroleum Co., Endeavor International Corporation, Evolution Petroleum Corp., Gulfport Energy Corp., GMX Resources Inc., Petroleum Development Corporation, PetroQuest Energy Inc., and Warren Resources Inc.

All of these cumulative total returns are computed assuming the value of the investment in our common stock and each index as $100.00 on December 31, 2005, and the reinvestment of dividends at the frequency with which dividends were paid during the applicable years. The years compared are 2006, 2007, 2008, 2009 and 2010.

	Dec. 31, 2005	Dec. 31, 2006	Dec. 31, 2007	Dec. 31, 2008	Dec. 31, 2009	Dec. 31, 2010
Small Cap Index	$100.00	$114.05	$142.59	$52.93	$56.95	$111.96
S&P 500	$100.00	$113.62	$117.63	$72.36	$89.33	$100.75
AXAS	$100.00	$58.52	$73.11	$13.64	$36.36	$86.55

The information contained above under the caption "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 for the years ended December 31, 2006 through 2010. The data should be read in conjunction with our Consolidated Financial Statements and Notes thereto, and other financial information included herein. See "Financial Statements and Supplementary Data" in Item 8.

	Year Ended December 31,				
	2006	2007	2008	2009	2010
	(Dollars in thousands except per share data)				
Total revenue	$ 51,077	$ 48,309	$ 100,310	$ 52,750	$ 59,030
Net income (loss)	$ 700	$ 56,702(1)	$ (52,403)(2)	$ (18,780)	$ 1,766(3)
Net income (loss) per common share – diluted	$ 0.02	$ 1.19	$ (1.07)	$ (0.34)	$ 0.02
Weighted average shares outstanding – diluted (in thousands)	43,862	47,593	49,005	55,499	77,362
Total assets	$ 116,940	$ 147,119	$ 211,839	$ 176,236	$ 182,909
Long-term debt, excluding current maturities	$ 127,614	$ 45,900	$ 130,835	$ 143,592	$ 140,940
Total stockholders' equity (deficit)	$ (22,165)	$ 55,847	$ 4,658	$ (18,363)	$ (14,976)

(1) Includes gain on sale of assets of $59.4 million.
(2) Includes proved property impairment of $116.4 million.
(3) Includes proved property impairment of $4.8 million.

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

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

General

We are an independent energy company primarily engaged in the acquisition, exploitation, development and production of oil and gas in the United States and Canada. 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.

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

- commodity prices and the effectiveness of our hedging arrangements;
- the level of total sales volumes of oil and gas;

- the availability of, and our ability to raise additional capital resources and provide liquidity to meet cash flow needs;
- the level of and interest rates on borrowings; and
- the level and success of exploration and development activity.

Commodity Prices and Hedging Arrangements. The results of our operations are highly dependent upon the prices received for our oil and gas 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 oil and gas 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 oil and gas production are dependent upon numerous factors beyond our control. Significant declines in prices for oil and gas 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 oil and gas have been volatile. During the first half of 2008, prices for oil and gas were sustained at record or near-record levels, however, during the second half of 2008, and first half of 2009, there was a significant drop in prices. Prices began to improve during the second half of 2009. During 2010, the price of oil increased significantly from the levels experienced in 2009. The New York Mercantile (NYMEX) price for West Texas Intermediate crude oil (WTI) averaged $79.51 per barrel in 2010 as compared to $61.82 per barrel in 2009. During 2010, the average price of gas increased slightly from an average NYMEX Henry Hub spot price of $3.94 per MMbtu in 2009 to $4.38 per MMbtu in 2010. Prices closed on December 31, 2010 at $91.38 per Bbl of oil and $4.41 per MMbtu of gas. If commodity prices decline, our revenue and cash flow from operations will also likely decline. In addition, lower commodity prices could also reduce the amount of oil and gas that we can produce economically. If gas prices remain depressed or oil prices decline significantly, our revenues, profitability and cash flow from operations may decrease which could cause us to alter our business plans, including reducing our drilling activities.

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 2010, differentials averaged ($8.14) per barrel of oil and ($0.41) per Mcf of gas compared to ($7.67) per barrel of oil and ($0.70) per Mcf of gas in 2009 and ($7.07) per barrel of oil and ($1.30) per Mcf of gas in 2008. We experienced greater oil differentials during 2010 compared to prior years because of the increased percentage of our production from the Rocky Mountain region which experiences higher differentials than our Permian Basin and Gulf Coast properties. Approximately 27% of our production during 2010 was from our Rocky Mountain properties. As the percentage of our production from the Rocky Mountain region increases, we expect that our price differentials will also increase. Increases in the differential between the benchmark prices for oil and gas and the wellhead price we receive could significantly reduce our revenues and our cash flow from operations.

Our credit facility required us to enter into hedging arrangements for specified volumes, which equated to approximately 80% of the estimated oil and gas production from our net proved developed producing reserves (as of December 1, 2010) through December 31, 2012 and 67% for 2013. By removing a significant portion of price volatility on our future oil and gas production, we believe we will mitigate, but not eliminate, the potential effects of changing commodity prices on our cash flow from operations for those periods. However, when prevailing market prices are higher than our contract prices, we will not realize increased cash flow on the portion of the production that has been hedged. We have sustained and in the future, we will sustain realized and unrealized losses on our derivative contracts if market prices are higher than our contract prices. Conversely, when prevailing market prices are lower than our contract prices, we will sustain realized and unrealized gains on our commodity derivative contracts. In 2008, we incurred a realized loss of $9.3 million and an unrealized gain of $40.5 million. In 2009, we incurred a realized gain of $17.9 million and an unrealized loss of $28.4 million. In 2010, we incurred a realized gain of $2.8 million and an unrealized gain of $11.4 million. 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 December 31, 2010:

	Fixed Price Swap			
	Oil		Gas	
Contract Periods	Daily Volume (Bbl)	Swap Price	Daily Volume (MMbtu)	Swap Price
2011	1,035	$76.61	9,580	$6.52
2012	946	70.89	8,303	6.77
2013	705	80.79	5,962	6.84

At December 31, 2010, the aggregate fair market value of our oil and gas derivative contracts was a liability of approximately $2.4 million.

Production Volumes. Our proved reserves will decline as oil and gas are produced, unless we find, acquire or develop additional properties containing proved reserves or conduct successful exploration and development activities. Based on the reserve information set forth in our reserve estimates as of December 31, 2010, our average annual estimated decline rate for net proved developed producing reserves is 12% 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 property sales. Our ability to acquire or find additional reserves in the future will be dependent, in part, upon the amount of available funds for acquisition, exploration and development projects.

We had capital expenditures during 2010 of $36.2 million. We have expanded our capital expenditure budget for 2011 to $60 million, an increase of approximately 66% over 2010. Approximately 50% of the expanded 2011 budget will be spent on unconventional horizontal oil wells in the Bakken/Three Forks and Niobrara plays in the Rocky Mountain region of the United States and the other 50% will target conventional oil plays in the Permian Basin and onshore Gulf Coast regions of the United States and in the province of Alberta, Canada. The 2011 capital expenditure budget is subject to change depending upon a number of factors, including the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the availability of sufficient capital resources, the results of our exploitation efforts, and our ability to obtain permits for drilling locations.

The following table presents historical net production volumes for the years ended December 31, 2008, 2009 and 2010:

	Year Ended December 31,		
	2008	2009	2010
Total production (MBoe)	1,607	1,634	1,422
Average daily production (Boepd)	4,391	4,476	3,896

Availability of Capital. As described more fully under “Liquidity and Capital Resources” below, our sources of capital are cash flow from operating activities, borrowings under our credit facility, cash on hand, proceeds from the sale of properties, and if an appropriate opportunity presents itself, the sale of debt or equity securities, although we may not be able to complete any financing on terms acceptable to us, if at all. As of December 31, 2010, we had $4.0 million of availability under our credit facility. In February 2011, we repaid $56.0 million of indebtedness with proceeds from our equity offering, which provided us $60.0 million of availability.

Borrowings and Interest. At December 31, 2010, we had a total of $136.0 million outstanding under our credit facility. In February 2011, we repaid $56.0 million of indebtdness with proceeds from our equity offering, giving us an outstanding balance of $80 million. 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 drilling opportunities which, in turn, will be dependent upon the level of our production volumes and commodity prices. In order to mitigate our interest rate exposure, we entered into an interest rate swap, effective August 12, 2008, to fix our floating LIBOR-based debt. The two-year interest rate swap for $100 million at a fixed rate of 3.367% originally expired on August 12, 2010. The interest rate swap was amended in February 2009 lowering our fixed rate to 2.95%. The interest rate swap was further amended in November 2009, lowering our fixed rate to 2.55% and extending the term through August 12, 2012.

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. At December 31, 2010, we operated properties accounting for approximately 88% of our PV-10, giving us substantial control over the timing and incurrence of operating and capital expenditures. We have identified numerous additional drilling locations (of which 154 were classified as proved undeveloped at December 31, 2010) on our existing leaseholds, the successful development of which we believe could significantly increase our production and proved reserves. Over the five years ended December 31, 2010, we drilled or participated in 103 gross (30.29 net) wells of which 96.1% resulted in commercially productive wells.

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. If our proved reserves decline in the future, our production may also decline and, consequently, our cash flow from operations and the amount that we are able to borrow under our credit facility will also decline. In addition, approximately 49% of our estimated proved reserves at December 31, 2010 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.

Results of Operations

Selected Operating Data. The following table sets forth operating data for the periods presented.

	Years Ended December 31, (dollars in thousands, except per unit data)		
	2008	2009	2010
Operating revenue(1):			
Oil sales	$50,954	$31,340	$36,321
Gas sales	48,130	20,489	21,729
Rig and other	1,226	921	980
Total operating revenues	$100,310	$52,750	$59,030
Operating income (loss) (2)	$(74,017)	$177	$2,807
Oil production (MBbls)	549.9	578.8	508.9
Gas production (MMcf)	6,342.9	6,329.2	5,478.9
Average oil sales price (per Bbl)(1)	$92.66	$54.15	$71.37
Average gas sales price (per Mcf) (1)	$7.59	$3.24	$3.97

(1) Revenue and average sales prices are before the impact of hedging activities.

(2) Operating loss includes a $116.4 million and a $4.8 million proved property impairment in 2008 and 2010, respectively.

Comparison of Year Ended December 31, 2010 to Year Ended December 31, 2009

Operating Revenue. During the year ended December 31, 2010, operating revenue from oil and gas sales increased by $6.3 million from $51.8 million in 2009 to $58.1 million in 2010. The increase in revenue was due to higher oil and gas prices in 2010 as compared to 2009 which were partially offset by decreased production volumes in 2010 as compared to 2009. The increase in commodity prices contributed $12.8 million to revenue while decreased sales volumes had a negative impact of $6.5 million.

Oil sales volumes decreased from 578.8 MBbls for the year ended December 31, 2009 to 508.9 MBbls for the same period of 2010. The decrease in oil sales volumes was due to sales of non-core properties during the latter part of the fourth quarter of 2009 and during 2010, natural field declines and the timing of new wells being brought on line. The divested properties produced 29.5 MBbls during 2010, compared to 67.8 MBbls during 2009. New wells brought onto production in 2010 contributed 23.9 MBbls to production for the year ended December 31, 2010. Gas sales volumes decreased from 6,329.2 MMcf for the year ended December 31 2009 to 5,478.9 MMcf for the year ended December 31, 2010. The decrease in gas production was due to sales of non-core properties during the latter part of the fourth quarter of 2009 and during 2010, natural field declines and the timing of new wells being brought on line. The divested properties produced 931.2 MMcf in 2009 compared to 754.9 MMcf in 2010. New wells brought onto production during 2010 contributed 190.8 MMcf to production for the year ended December 31, 2010.

Average sales prices in 2010, before realized gain (loss) on derivative contracts were:

- $71.37 per Bbl of oil, and
- $ 3.97 per Mcf of gas.

Average sales prices in 2009, before realized gain (loss) on derivative contracts were:

- $54.15 per Bbl of oil, and
- $ 3.24 per Mcf of gas.

Lease Operating Expenses (“LOE”). LOE decreased from $20.4 million in 2009 to $19.6 million in 2010. LOE per Boe for the year ended December 31, 2010 was $13.81 compared to $12.50 for the same period of 2009. The increase in LOE per Boe was attributable to lower production volumes in 2010 as compared to 2009.

Production and Ad Valorem Taxes. Production and ad valorem taxes increased from $5.8 million in 2009 to $5.9 million in 2010 as a result of higher commodity prices which result in higher production taxes.

General and Administrative (“G&A”) Expense. G&A expense, excluding stock-based compensation, increased from $6.5 million in 2009 to $7.3 million in 2010. The increase in G&A was primarily related to the opening of our Canadian office in September 2009. G&A per Boe was $5.14 for the year ended December 31, 2010 compared to $3.96 for the same period of 2009. The increase in G&A per Boe was primarily due to lower production volumes and higher costs in 2010 compared to 2009.

Stock-based Compensation. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options vesting period. In addition to options, restricted shares of common stock have been granted and are valued at the date of grant and expense is recognized over their vesting period. For the years ended December 31, 2010 and 2009, stock-based compensation was approximately $1.6 million and $1.2 million, respectively. The increase in 2010 as compared to 2009 was due to the grant of options in the fourth quarter of 2009 related to the Merger and new grants during 2010.

Depletion, Depreciation and Amortization (“DD&A”) Expenses. DD&A expense decreased from $17.9 million in 2009 to $16.2 million in 2010. The decrease in DD&A was primarily the result of a lower reserve base due to the sale of properties during 2010 and the contribution of acreage to Blue Eagle, which also reduced our full cost pool. DD&A per Boe for 2009 was $10.95 as compared to $11.40 per Boe in 2010.

Interest Expense. Interest expense decreased to $9.1 million in 2010 compared to $11.3 million for 2009. The decrease in interest expense for the year ended December 31, 2010 was primarily due to lower levels of debt as compared to 2009.

Income taxes. For the year ended December 31, 2009, we incurred $1.3 million in federal and state income taxes. The taxes were the result of a tax basis gain on the Merger. An income tax benefit of $79,000 was recognized in 2010 as a result of a decrease in the $1.3 million tax basis gain on the Merger.

Loss (gain) on 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 ASC 815; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Our derivative contracts consist of commodity swaps and interest rate swaps. The estimated value of our derivative contracts was a liability of approximately $5.8 million as of December 31, 2010. When our derivative contract prices are higher than prevailing market prices, we incur realized and unrealized gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur realized and unrealized losses. For the year ended December 31, 2010, we realized a gain on our derivative contracts of $500,000, which included a realized gain of $2.8 million on our commodity swaps and a realized loss of $2.3 million on our interest rate swap. For the year-ended December 31, 2010, we incurred an unrealized gain of $10.3 million on our derivative contracts, which included an unrealized gain of $11.4 on our commodity swaps and an unrealized loss of $1.1 million on our interest rate swap. For the year ended December 31, 2009, we realized a gain on our derivative contracts of $15.3 million, which included a realized gain of $17.9 million on our commodity swaps and a realized loss of $2.6 million on our interest rate swap. For the year-ended December 31, 2009, we incurred an unrealized loss of $27.6 million, which included an unrealized loss of $28.4 million on our commodity swaps and an unrealized gain of $0.8 million on our interest rate swap.

Other Expense. During 2009, other expense consisted primarily of costs related to the planned initial public offering of the Partnership which had previously been capitalized.

Ceiling Limitation Write-down. We record the carrying value of our oil and gas properties using the full cost method of accounting for oil and gas properties. Under this method, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under the full cost accounting rules, the net capitalized cost of oil and gas properties less related deferred taxes, are limited by country, to the lower of the unamortized cost or the cost ceiling, defined as the sum of the present value of estimated unescalated future net revenues from proved reserves, discounted at 10%, 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. If the net capitalized cost of oil and gas properties exceeds the ceiling limit, we are subject to a ceiling limitation write-down to the extent of such excess. A ceiling limitation write-down is a charge to earnings which does not impact cash flow from operating activities. However, such write-downs do impact the amount of our stockholders' equity and reported earnings. As of December 31, 2010, our net capitalized costs of oil and gas properties in the United States did not exceed the present value of our estimated proved reserves; however, the net capitalized cost of our oil and gas properties in Canada exceeded the present value of our estimated proved reserves by $4.8 million, resulting in a write down of $4.8 million. These amounts were calculated in accordance with SEC rules utilizing the twelve month first-day-of-the-month average oil and gas prices for the year ended 2010 which were $79.43 per Bbl for oil and $4.45 per Mcf for gas as adjusted to reflect the expected realized prices for our oil and gas reserves. As of December 31, 2009, our net capitalized costs of our United States oil and gas properties did not exceed the present value of our estimated proved reserves. As of December 31, 2009, we did not own any properties outside of the United States.

The risk that we will be required to write-down the carrying value of our oil and gas assets increases when oil and gas prices are depressed or volatile. In addition, write-downs may occur if we have substantial downward revisions in our estimated proved reserves. We cannot assure you that we will not experience additional write-downs in the future. If commodity prices decline or if any of our proved reserves are revised downward, a further write-down of the carrying value of our oil and gas properties may be required. Based on managements' review of average first-day-of-the-month prices for the twelve months of April 2010 through March 2011, we do not anticipate a write down at the end of the first quarter of 2011.

Non-controlling interest. Non-controlling interest represents the share of net income (loss) of the Partnership for the period owned by the partners other than Abraxas. For the year ended December 31, 2009, the non-controlling interest in the net income of the Partnership was approximately $9.7 million. The Partnership was merged into Abraxas on October 5, 2009; accordingly, there was no non-controlling interest adjustment for the year ended December 31, 2010.

Equity in (gain) loss of joint venture. Our investment in Blue Eagle, in which we do not have a majority interest, but do have significant influence, is accounted for under the equity method. Under the equity method of accounting, our share of net income (loss) from the joint venture is reflected as an increase (decrease) in our investment account and is also recorded as equity investment income (loss). Our net share of the joint ventures earnings or losses is reported as "Equity in (gain) loss of joint venture" in the consolidated statements of operations. For year ended December 31, 2010, our net share of the joint venture's loss was $473,000.

Comparison of Year Ended December 31, 2009 to Year Ended December 31, 2008

Operating Revenue. During the year ended December 31, 2009, operating revenue from oil and gas sales decreased by $47.3 million from $99.1 million in 2008 to $51.8 million in 2009. The decrease in revenue was due to lower oil and gas prices in 2009 as compared to 2008 which were partially offset by increased production volumes in 2009 as compared to 2008. The decrease in commodity prices had a negative impact of $49.8 million while increased production volumes contributed $2.5 million to revenue.

Oil production volumes increased from 549.9 MBbls for the year ended December 31, 2008 to 578.8 MBbls for the same period of 2009, primarily due to production from new wells placed on production during 2009. Gas production volumes decreased from 6,342.9 MMcf for the year ended December 31, 2008 to 6,329.2 MMcf for the same period of 2009, primarily due to natural field declines.

Average sales prices in 2009, before realized gain (loss) on derivative contracts were:

- $54.15 per Bbl of oil, and
- $ 3.24 per Mcf of gas.

Average sales prices in 2008, before realized gain (loss) on derivative contracts were:

- $92.66 per Bbl of oil, and
- $ 7.59 per Mcf of gas.

Lease Operating Expenses ("LOE"). LOE increased from $17.5 million in 2008 to $20.4 million in 2009 as a result of higher operating costs. LOE per Boe for the year ended December 31, 2009 was $12.50 compared to $10.91 for the same period of 2008. The increase in LOE per Boe was attributable to higher operating costs.

Production and Ad Valorem Taxes. Production and ad valorem taxes decreased from $9.1 million in 2008 to $5.8 million in 2009 as a result of lower commodity prices which result in lower production taxes.

General and Administrative ("G&A") Expense. G&A expense, excluding stock-based compensation, increased from $5.7 million in 2008 to $6.5 million in 2009. The increase in G&A in 2009 as compared to 2008 was primarily due to higher professional and consulting fees, as well as increased cost for director fees related to the Merger and the opening of our Canadian office in September 2009. G&A per Boe was $3.96 for 2009 compared to $3.56 for the same period of 2008. The increase in G&A per Boe cost was attributable to the higher G&A during 2009 as compared to 2008.

Stock-based Compensation. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options vesting period. In addition to options, restricted shares of common stock have been granted and are valued at the date of grant and expense is recognized over their vesting period. For the years ended December 31, 2009 and 2008, stock-based compensation was approximately $1.2 million and $1.4 million, respectively. The decrease in 2009 as compared to 2008 was due to expenses related to higher valued options granted in prior years that have been fully amortized.

Depreciation, Depletion and Amortization ("DD&A") Expenses. DD&A expense decreased from $23.3 million in 2008 to $17.9 million in 2009. The decrease in DD&A was primarily the result of the producing property impairment for the year ended December 31, 2008 which reduced our full cost pool. DD&A per Boe for 2009 was $10.95 as compared to $14.53 in 2008. The decrease in DD&A per Boe in 2009 was primarily the result of the book value of our full cost pool being reduced due to the impairment incurred in 2008.

Interest Expense. Interest expense increased to $11.3 million in 2009 compared to $10.5 million for 2008. The increase in interest expense in 2009 was primarily due to higher levels of debt and higher interest rates as compared to 2008.

Income taxes. For the year ended December 31, 2009 we incurred $1.3 million in federal and state income taxes. The taxes were the result of a tax basis gain on the Merger. No income tax expense or benefit was recognized in 2008 due to losses or loss carryforwards and valuation allowance, which has been recorded against such benefits.

Loss (gain) on 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 ASC 815; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Our derivative contracts consist of commodity swaps and interest rate swaps. The estimated value of our derivative contracts was a liability of approximately $16.3 million as of December 31, 2009. When our derivative contract prices are higher than prevailing market prices, we incur realized and unrealized gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur realized and unrealized losses. For the year ended December 31, 2009, we realized a gain on our derivative contracts of $15.3 million, which included a realized gain of $17.9 million on our commodity swaps and a realized loss of $2.6 million on our interest rate swap. For the year-ended December 31, 2009, we incurred an unrealized loss of $27.6 million, which included an unrealized loss of $28.4 million on our commodity swaps and an unrealized gain of $0.8 million on our interest rate swap. For the year ended December 31, 2008, we realized a loss on our derivative contracts of $9.5 million, which included a realized loss of $9.3 million on our commodity swaps and a realized loss of $260,000 on our interest rate swap. For the year ended December 31, 2008, we incurred an unrealized gain of $37.9 million, which included an unrealized gain of $40.5 million on our commodity swaps and an unrealized loss of $2.6 million on our interest rate swap.

Other Expense. For the year ended December 31, 2008, as a result of the exchange and registration rights agreement whereby Partnership unitholders, under certain circumstances, could convert their Partnership units into Abraxas common stock, we recognized an expense of $7.4 million, including approximately $293,000 relating to shares converted during the fourth quarter of 2008 and $7.1 million representing the fair value of potential conversions. During 2009, other expense consisted primarily of costs related to the planned initial public offering of the Partnership which had previously been capitalized.

Ceiling Limitation Write-down. We record the carrying value of our oil and gas properties using the full cost method of accounting for oil and gas properties. Under this method, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under the full cost accounting rules, the net capitalized cost of oil and gas properties less related deferred taxes, are limited by country, to the lower of the unamortized cost or the cost ceiling, defined as the sum of the present value of estimated unescalated future net revenues from proved reserves, discounted at 10%, 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. If the net capitalized cost of oil and gas properties exceeds the ceiling limit, we are subject to a ceiling limitation write-down to the extent of such excess. A ceiling limitation write-down is a charge to earnings which does not impact cash flow from operating activities. However, such write-downs do impact the amount of our stockholders' equity and reported earnings. As of December 31, 2008, our net capitalized costs of our United States oil and gas properties exceeded the present value of our estimated proved reserves by $116.4 million, resulting in a write down of $116.4 million. These amounts were calculated in accordance with previous SEC rules utilizing 2008 year-end prices of $44.60 per Bbl for oil and $5.62 per Mcf for gas as adjusted to reflect the expected realized prices for our oil and gas reserves. As of December 31, 2009, our net capitalized costs of our United States oil and gas properties did not exceed the present value of our estimated proved reserves. As of December 31, 2008 and 2009, we did not own any properties outside of the United States.

The risk that we will be required to write-down the carrying value of our oil and gas assets increases when oil and gas prices are depressed or volatile. In addition, write-downs may occur if we have substantial downward revisions in our estimated proved reserves. We cannot assure you that we will not experience additional write-downs in the future. If commodity prices decline or if any of our proved reserves are revised downward, a further write-down of the carrying value of our oil and gas properties may be required.

Non-Controlling Interest. Non-controlling interest represents the share of net income (loss) of the Partnership for the period owned by the partners other than Abraxas. Additionally, in accordance with generally accepted accounting principles in effect at the time, when cumulative losses applicable to the non-controlling interest exceeded the non-controlling interest equity capital in the entity, such excess are charged to the earnings of the controlling interest. For the year ended December 31, 2008, primarily as a result of the ceiling test impairment, losses applicable to the non-controlling interest exceeded the controlling interest equity capital by $9.3 million. As a result, $9.3 million was charged to earnings attributable to Abraxas and reflected as a reduction of the loss applicable to the non-controlling interest.

Liquidity and Capital Resources

General. The oil and gas 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:

- the development of existing properties, including drilling and completion costs of wells;
- acquisition of interests in additional oil and gas 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 grow the business through the development of existing properties and the acquisition of new properties.

Our principal sources of capital are cash flow from operations, borrowings under our credit facility, cash on hand, proceeds from the sale of properties, and if an opportunity presents itself, the sale of debt or equity securities, although we may not be able to complete any financings on terms acceptable to us, if at all.

Working Capital (Deficit). At December 31, 2010, our current liabilities of $37.5 million exceeded our current assets of $28.6 million resulting in a working capital deficit of $8.9 million. This compares to a working capital deficit of $17.4 million at December 31, 2009. Current liabilities at December 31, 2010 primarily consisted of the current portion of derivative liabilities of $9.7 million, trade payables of $23.6 million, revenues due third parties of $3.0 million, and other accrued liabilities of $1.1 million.

Capital Expenditures. Capital expenditures in 2008, 2009 and 2010 were $174.6 million, $16.5 million and $36.4 million, respectively. The table below sets forth the components of these capital expenditures:

	Year Ended December 31,		
	2008	2009	2010
	(dollars in thousands)		
Expenditure category:			
Exploration/Development	$40,564	$16,151	$36,172
Acquisition	127,671	—	—
Facilities and other	6,351	320	276
Total	$174,586	$16,471	$36,448

During 2008, capital expenditures included $127.7 million for the acquisition of properties from St. Mary Land & Exploration Company and other smaller acquisitions, as well as the development of our oil and gas properties. During 2009 and 2010, capital expenditures were primarily for the development of our existing properties.

We anticipate making capital expenditures in 2011 of $60.0 million. The 2011 capital expenditure budget is subject to change depending upon a number of factors, including the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the availability of sufficient capital resources, the results of our exploitation efforts, and ability to obtain permits for drilling locations. With the increased number of drilling rigs running, particularly in the Williston Basin and in the Eagle Ford Shale play, together with the increased number of stages on a given frac job, frac crews and equipment are in short supply. As a result, there may be a delay in procuring services for the multi-stage frac jobs that we have planned for our operated wells, which would delay the completion of successfully drilled wells. Our capital expenditures could also include expenditures for the acquisition of producing properties, if such opportunities arise. Additionally, the level of capital expenditures will vary during future periods depending on economic and industry conditions and commodity prices. There was a significant decline in oil and gas prices beginning in the second quarter of 2008, while oil prices improved during the second half of 2009 and through 2010, gas prices remain fairly weak. Should the prices of oil and gas decline and if our costs of operations increase or if our production volumes decrease, our cash flows will decrease which may result in a reduction of the capital expenditure budget. If we decrease our capital expenditure budget, we may not be able to offset oil and gas production decreases caused by natural field declines.

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

	Year Ended December 31,		
	2008	2009	2010
	(dollars in thousands)		
Net cash provided by operating activities	$43,387	$44,136	$24,102
Net cash used in investing activities	(173,944)	(14,096)	(15,048)
Net cash provided by (used in) financing activities	113,545	(30,103)	(10,816)
Total	$(17,012)	$(63)	$(1,762)

Operating activities for the year ended December 31, 2010 provided $24.1 million in cash. Net income plus non-cash expense items and net changes in operating assets and liabilities accounted for most of these funds, including the non-cash property impairment of $4.8 million. Financing activities used $10.8 million for the year ended December 31, 2010 which was predominately the reduction of long-term debt. Investing activities used $15.0 million in 2010 for the development of our oil and gas properties net, of proceeds from sale of properties of $21.4 million.

Operating activities for the year ended December 31, 2009 provided $44.1 million in cash. Net income plus non-cash expense items and net changes in operating assets and liabilities and the monetization of our derivative contracts accounted for most of these funds. Financing activities used $30.1 million for the year ended December 31, 2009 which was predominately the reduction of long-term debt. Investing activities used $14.1 million in 2009 for the development of our oil and gas properties, net of proceeds from the sale of properties of $2.4 million.

Operating activities for the year ended December 31, 2008 provided $43.4 million in cash. Net income plus non-cash expense items and net changes in operating assets and liabilities accounted for most of these funds, including the non–cash proved property impairment of $116.4 million. Financing activities provided $113.5 million for the year ended December 31, 2008, including proceeds of long-term borrowing in connection with the St. Mary acquisition. Investing activities used $173.9 million in 2008, including $127.7 million for the St. Mary acquisition as well as the development of our oil and gas properties.

Future Capital Resources. Our principal sources of capital going forward are cash flow from operations, borrowings under our credit facility, cash on hand, proceeds from the sale of properties, and if an opportunity presents itself, the sale of debt or equity securities, although we may not be able to complete financing on terms acceptable to us, if at all.

In the fourth quarter of 2009 and throughout 2010, we sold certain non-operated, non-core assets, to generate cash for debt repayment and to accelerate our drilling program. We sold properties in nine different states for combined net proceeds of approximately $32.2 million ($2.4 million in 2009 and $29.8 million in 2010, of which $8.4 million was received in February 2011) at various property auctions to numerous buyers. In total, these properties produced approximately 611 Boepd during 2009 and had 2.3 MMBoe of proved reserves as of December 31, 2009. The first $10.0 million of net proceeds was used to repay the term loan portion of our credit facility and the remaining $22.2 million was used to repay outstanding indebtedness under the revolving portion of the credit facility, for capital expenditures and general corporate purposes.

On February 1, 2011, we completed a public offering of 23.6 million shares of common stock (of which 8.5 million shares were sold by certain selling stockholders) at a public offering price of $4.40 per share for total net proceeds to us of approximately $62.0 million, after estimated fees and expenses. We used the net proceeds from the offering to repay indebtedness outstanding under our credit facility, to increase our 2011 capital expenditure budget and for general corporate purposes. We did not receive any proceeds from the sale of shares by the selling stockholders.

Cash from operating activities is dependent upon commodity prices and production volumes. Oil and gas prices are volatile and declined significantly during the second half of 2008 and first part of 2009. Oil prices increased during the second six months of 2009 and during 2010, and while gas prices have strengthened somewhat, they remain weak. A decrease in commodity prices from current levels could reduce our cash flows from operations. This could cause us to alter our business plans, including reducing our exploration and development plans. Unless we otherwise expand and develop reserves, our production volumes may decline as reserves are produced. In the future we may continue to 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 and develop 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 oil and gas reservoirs will be found. Additionally, due to the increased number of drilling rigs running, particularly in the Williston Basin and in the Eagle Ford Shale play, together with the increased number of stages on a given frac job, frac crews and equipment are in short supply. As a result, there may be a delay in procuring services for the multi-stage frac jobs that we have planned for our operated wells, which would delay the completion of successfully drilled wells. If our proved reserves decline in the future, our production will also decline and, consequently, our cash flow from operations and the amount that we are able to borrow under our credit facility will also decline. The risk of not finding commercially productive reservoirs will be compounded by the fact that 49% of our total estimated proved reserves at December 31, 2010 were classified as undeveloped.

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.

Below is a schedule of the future payments that we are obligated to make based on agreements in place as of December 31, 2010:

Contractual Obligations (in thousands)	Total	Payments due in twelve month periods ending: December 31, 2011	December 31, 2012-2013	December 31, 2014-2015	Thereafter
Long-Term Debt (1)	$141,092	$152	$136,336	$4,604	$—
Interest on long-term debt (2)	15,128	8,144	6,591	393	—
Lease obligations (3)	142	46	92	4	—
Total	$156,362	$8,342	$143,019	$5,001	$—

(1) These amounts represent the balances outstanding under our credit facility and the real estate lien note. These payments assume that we will not borrow additional funds.

(2) Interest expense assumes the balances of long-term debt at the end of the period and current effective interest rates.

(3) Lease on office space in Calgary, Alberta, which expires on January 31, 2014.

We maintain a reserve for costs associated with the retirement of tangible long-lived assets. At December 31, 2010, our reserve for these obligations totaled $7.7 million for which no contractual commitments exist. For additional information relating to this obligation, see Note 1 of the Notes to Consolidated Financial Statements.

Off-Balance Sheet Arrangements. At December 31, 2010, 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 material effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that are 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, 2010, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on us.

Other obligations. We make and will continue to make substantial capital expenditures for the acquisition, exploration, development and production of oil and 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, borrowings under our credit facilities, sales of debt and equity 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 debt consisted of the following:

	December 31, 2009	December 31, 2010
	(in thousands)	
Credit facility – Term portion	$8,000	$—
Credit facility – Revolving portion	138,500	136,000
Real estate lien note	5,233	5,092
	151,733	141,092
Less current maturities	(8,141)	(152)
	$143,592	$140,940

Credit Facility

On October 5, 2009, in connection 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, which was amended on August 18, 2010. 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. The term portion of the credit facility was paid in full on March 30, 2010. As of December 31, 2010, $136.0 million was outstanding under the revolving portion of the credit facility. This outstanding amount was reduced to $80.0 million after applying the net proceeds from the equity offering that closed on February 1, 2011.

The revolving portion of the credit facility has a maximum commitment of $300.0 million and availability is subject to a borrowing base. The borrowing base is currently $140.0 million and 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, are able to make one additional borrowing base redetermination during any six-month period between scheduled redeterminations and we are able to request one redetermination during any six-month period between scheduled redeterminations. The lenders are also able to make a redetermination in connection with any sales of producing properties with a market value of 5% or more of our then-current borrowing base and in connection with any hedge termination which could reduce the collateral value by 5% or more. Our borrowing base of $140.0 million was determined based upon our reserve report dated June 30, 2010. Our borrowing base can never exceed the $300.0 million maximum commitment amount. Outstanding amounts under the revolving portion of the credit facility bear interest at (a) the greater of (1) the reference rate announced from time to time by Société Générale, (2) the Federal Funds Rate plus 0.5%, and (3) a rate determined by Société Générale as the daily one-month LIBOR plus, in each case, (b) 1.5%—2.75%, depending on the utilization of the borrowing base, or, if we elect, at the greater of (1) 2.0% and (2) LIBOR plus, in each case, 2.5%—3.75%, depending on the utilization of the borrowing base. At December 31, 2010, the interest rate on the revolving portion of the credit facility was 5.75%.

Subject to earlier termination rights and events of default, the stated maturity date of the credit facility is October 5, 2012. Interest is payable quarterly on reference rate advances and not less than quarterly on Eurodollar advances. We are permitted to terminate the credit facility and are able, from time to time, to permanently reduce the lenders' aggregate commitment under the credit facility in compliance with certain notice and dollar increment requirements.

Each of our subsidiaries has guaranteed our 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 our and our subsidiary guarantors' material property and assets.

Under the credit facility, we are subject to customary covenants, including certain financial covenants and reporting requirements. We are required to maintain a current ratio as of the last day of each quarter of not less than 1.00 to 1.00 and an interest coverage ratio as of the last day of each quarter of not less than 2.50 to 1.00. We are also required to maintain a total debt to EBITDAX ratio as of the last day of each quarter of not more than 4.00 to 1.00. The current ratio is defined as the ratio of consolidated current assets to consolidated current liabilities. For the purposes of this calculation, current assets include the portion of the borrowing base which is undrawn but excludes any cash deposited with or at the request of a counter-party to a hedging arrangement and any assets representing a valuation account arising from the application of ASC 815 and ASC 410-20 and current liabilities exclude the current portion of long-term debt and any liabilities representing a valuation account arising from the application of ASC 815 and ASC 410-20. The interest coverage ratio is defined as the ratio of consolidated EBITDAX to consolidated interest expense for the four fiscal quarters ended on the calculation date after giving pro forma effect to the Merger. For the purposes of this calculation, EBITDAX is consolidated net income plus interest expense, oil and gas exploration expenses, taxes, depreciation, amortization, depletion and other non-cash charges including non-cash charges resulting from the application of ASC 718 , ASC 815 and ASC 410-20 plus all realized net cash proceeds arising from the settlement or monetization of any hedge contracts or upon the termination of any hedge contract minus all non-cash items of income which were included in determining consolidated net income, including all non-cash items resulting from the application of ASC 815 and ASC 410-20. Interest expense includes total interest, letter of credit fees and other fees and expenses incurred in connection with any debt. The total debt to EBITDAX ratio is defined as the ratio of total debt to consolidated EBITDAX for the four fiscal quarters ended on the calculation date after giving pro forma effect to the Merger. For the purposes of this calculation, total debt is the outstanding principal amount of debt, excluding debt associated with the office building, and obligations with respect to surety bonds and hedge arrangements. We were in compliance with all covenants as of December 31, 2010.

As of December 31, 2010, the current ratio was 1.01 to 1.00, the interest coverage ratio was 3.16 to 1.00 and the total debt to EBITDAX ratio was 3.96 to 1.00.

The credit facility also required that we enter into hedging arrangements for specified volumes, which equated to approximately 80% of the estimated oil and gas production from our net proved developed producing reserves (as of December 31, 2010) through December 31, 2012 and 67% for 2013. We satisfied this requirement by assuming all of the Partnership's derivative contracts in connection with the Merger.

In addition to the foregoing and other customary covenants, the credit facility contains a number of covenants that, among other things, restrict our ability to:

- incur or guarantee additional indebtedness;
- transfer or sell assets;
- create liens on assets;
- engage in transactions with affiliates other than on an "arm's-length" basis;
- make any change in the principal nature of our 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.

Real Estate Lien Note

On May 9, 2008, we entered into an advancing line of credit in the amount of $5.4 million for the purchase and finish out of a building to serve as our corporate headquarters. This note was refinanced in November 2008. The note bears interest at a fixed rate of 6.375%, and is payable in monthly installments of principal and interest of $39,754 based on a twenty year amortization. The note matures in May 2015 at which time the outstanding balance becomes due. The note is secured by a first lien deed of trust on the property and improvements. As of December 31, 2010, $5.1 million was outstanding on the note.

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 our credit facility, we entered into commodity swaps on approximately 80% of our estimated oil and gas production from our net proved developed producing reserves (as of December 31, 2010) through December 31, 2012 and 67% for 2013.

The following table sets forth our derivative contract position as of December 31, 2010:

	Fixed Price Swap			
	Oil		Gas	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (MMbtu)	Swap Price (per MMbtu)
2011	1,035	$76.61	9,580	$6.52
2012	946	70.89	8,303	6.77
2013	705	80.79	5,962	6.84

By removing a significant portion of price volatility on our future oil and gas production, we believe that we will mitigate, but not eliminate, the potential effects of changing commodity prices on our cash flow from operations. However, when prevailing market prices are higher than our contract prices, we will not realize increased cash flow on the portion of the production that has been hedged. We have sustained, and in the future will sustain, realized and unrealized losses on our derivative contracts when market prices are higher than our contract prices. Conversely, when prevailing market prices are lower than our contract prices, we will sustain realized and unrealized gains on our commodity derivative contracts. For the year ended December 31, 2010, we incurred a realized gain of $2.8 million and an unrealized gain of $11.4 million on our commodity derivative contracts. For the year ended December 31, 2009, we incurred a realized gain of $17.9 million and an unrealized loss of $28.4 million on our commodity derivative contracts. If the disparity between our contract prices and market prices continues, we will sustain realized and unrealized gains or losses on our derivative contracts. While unrealized gains and losses do not impact our cash flow from operations, realized gains and losses do impact our cash flow from operations. In addition, as our derivative contracts expire over time, we expect to enter into new derivative contracts at then-current market prices. If the prices at which we hedge future production are significantly lower than our existing derivative contracts, our future cash flow from operations would likely be materially lower. In addition, borrowings under our credit facility bear interest at floating rates. 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 drilling opportunities which, in turn, will be dependent upon the level of our production volumes and commodity prices.

See "—Quantitative and Qualitative Disclosures about Market Risk—Hedging Sensitivity" for further information.

Net Operating Loss Carryforwards

At December 31, 2010, we had, subject to the limitation discussed below, $141.8 million of net operating loss carryforwards for U.S. tax purposes and $1.1 million for Canadian tax purposes. The U.S. loss carryforwards will expire through 2030 and the Canadian carryforward will expire in 2030, if not utilized.

Uncertainties exist as to the future utilization of the operating loss carryforwards under the criteria set forth under ASC 740-10. Therefore, we have established a valuation allowance of $91.9 million for deferred tax assets at December 31, 2010.

We account for uncertain tax positions under provisions of ASC 740-10. ASC 740-10 did not have any effect on the Company's financial position or results of operations for the year ended December 31, 2010. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of December 31, 2010, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years from 2000 through 2010 remain open to examination by the tax jurisdictions to which the Company is subject.

Related Party Transactions

We have adopted a policy that transactions between us and our officers, directors, principal stockholders, or affiliates of any of them, will be on terms no less favorable to us than can be obtained on an arm's length basis in transactions with third parties and must be approved by our audit committee.

Environmental Regulations

Various federal, provincial, state and local laws and regulations covering the discharge of materials into the environment, or otherwise relating to the protection of the environment, affect our operations and costs as a result of their effect on oil and gas exploration, development and production operations. These laws and regulations could cause us to incur remediation or other corrective action costs in connection with a release of regulated substances, including oil, into the environment. In addition, we have acquired certain oil and gas properties from third parties whose actions with respect to the management and disposal or release of hydrocarbons or other wastes were not under our control, and under environmental laws and regulations, we could be required to remove or remediate wastes disposed of or released by prior owners or operators. We also could incur costs related to the clean-up of sites to which we sent regulated substances for disposal or to which we sent equipment for cleaning, and for damages to natural resources or other claims related to releases of regulated substances at such sites. In addition, we could be responsible under environmental laws and regulations for oil and gas properties in which we own an interest but are not the operator. Moreover, we are subject to the EPA's rule requiring annual reporting of greenhouse gas (GHG) emissions.

Compliance with such laws and regulations increases our overall cost of business, but has not had, to date, a material adverse effect on our operations, financial condition, results of operations or competitive position. It is not anticipated, based on current laws and regulations, that we will be required in the near future to expend amounts (whether for environmental control facilities or otherwise) that are material in relation to our total exploration and development expenditure program in order to comply with such laws and regulations, but, inasmuch as such laws and regulations are frequently changed, we are unable to predict the ultimate cost of compliance or the effect on our operations, financial condition, results of operations and competitive position.

We are aware of the increasing focus of local, state, national and international regulatory bodies on GHG emissions and climate change issues. In addition to the EPA's rule requiring annual reporting of GHG emissions, we are also aware of legislation proposed by United States lawmakers to reduce GHG emissions. We are unable to predict the timing, scope and effect of any such proposed laws, regulations and treaties, but the direct and indirect costs of such laws, regulations and treaties (if enacted) could materially and adversely affect our business, results of operations, financial condition and competitive position.

We strive to reduce GHG emissions throughout our operations which is in the best interest of the environment and a generally good business practice. We will continue to review the risks to our business and operations associated with all environmental matters, including climate change. In addition, we will continue to monitor and assess any new policies, legislation or regulations in the areas where we operate to determine the impact on our operations and take appropriate actions, where necessary.

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 Oil and Gas Activities. SEC Regulation S-X defines the financial accounting and reporting standards for companies engaged in oil and gas 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 but 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 oil and gas 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 oil and gas 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 oil and gas 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 2010 relating to our proved oil and gas properties in Canada. Our oil and gas reserves have a relatively long life. However, temporary drops in commodity prices can have a material impact on our business including impact from impairment testing procedures associated with the full cost method of accounting as discussed below.

Under full cost accounting rules, the net capitalized cost of oil and gas properties may not exceed a "ceiling limit" which is based upon the present 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 oil and gas properties exceed the ceiling limit, we must charge the amount of the excess to earnings. This is called a "ceiling limitation write-down." This charge does not impact cash flow from operating activities, but does reduce our stockholders' equity and reported earnings. The risk that we will be required to write down the carrying value of oil and gas properties increases when oil and gas prices are depressed. In addition, write-downs may occur if we experience substantial downward adjustments to our estimated proved reserves. An expense recorded in one period may not be reversed in a subsequent period even though higher oil and gas prices may have increased the ceiling applicable to the subsequent period. We apply the full cost ceiling test on a quarterly basis on the date of the latest balance sheet presented.

Estimates of Proved Oil and Gas 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 predominately 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 costs on the date of the estimate and for the years ended December 31, 2009 and 2010, oil and gas prices were based on the average 12-month first-day-of-the-month pricing as compared to end of period prices in prior years. Actual future prices and costs may be materially higher or lower than the prices and costs used in 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 is 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 we amortize these costs as a component of our depletion expense.

Accounting for Derivatives. We account for derivative 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. The derivative instruments we utilize are based on index prices that may and often do differ from the actual oil and gas prices realized in our operations. Our derivative contract transactions do not qualify for hedge accounting as prescribed by ASC 815; therefore, fluctuations in the market value of the derivative contract are recognized in earnings during the current period. Our derivative contracts consist of commodity swaps and interest rate swaps. Due to the volatility of oil and gas 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, 2009 and 2010, the net market value of our commodity derivatives was a net liability of $14.0 million and $2.5 million, respectively. The market value of our interest rate derivative was a liability of $2.2 million and $3.3 million at December 31, 2009 and 2010, 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. Additional information about management's assumptions can be found in note 8 to the consolidated financial statements. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options vesting period. Restricted stock awards are awards of common stock that are subject to restrictions on transfer and to a risk of forfeiture if the awardee terminates employment with the Company prior to the lapse of the restrictions. The value of such stock is determined using the market price on the grant date and expense is recognized over the vesting period. For the years ended December 31, 2008, 2009 and 2010, stock-based compensation was approximately $1.4 million, $1.2 million, and $1.6 million, respectively.

Equity Method Investment. Our investment in an unconsolidated joint venture, in which we do not have a majority interest, is accounted for under the equity method. Under the equity method of accounting, our share of net income (loss) from our equity investment is reflected as an increase (decrease) in our investment account "Investment in joint venture" and is also recorded as "Equity in loss of joint venture" in "other (income) expense".

We review our equity method investment for potential impairment whenever events or changes in circumstances indicate that an other-than-temporary decline in the value of the investment has occurred.

Recent Accounting Pronouncements

In January 2010, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update No. 2010-6, "Improving Disclosures about Fair Value Measurements" ("ASU No. 2010-06"). ASU No. 2010-06 amends FASB Accounting Standards Codification ("ASC") Topic 820, "Fair Value Measurements and Disclosures," to require additional information to be disclosed principally regarding Level 3 measurements and transfers to and from Level 1 and 2. In addition, enhanced disclosure is required concerning inputs and valuation techniques used to determine Level 2 and Level 3 measurements. This guidance is generally effective for interim and annual reporting periods beginning after

December 15, 2009; however, requirements to disclose separately purchases, sales, issuances, and settlements in the Level 3 reconciliation are effective for fiscal years beginning after December 15, 2010 (and for interim periods within such years). The update will not have a material impact on the Company's consolidated results of operations or financial position.

In February 2010, the FASB issued Accounting Standards Update No. 2010-09, "Amendments to Certain Recognition and Disclosure Requirements" ("ASU No. 2010-09"). ASU No. 2010-09 amends FASB ASC Topic 855-10, "Subsequent Events," to remove the requirement for an SEC filer to disclose the date through which subsequent events have been evaluated in both issued and revised financial statements. This change alleviates potential conflicts between ASC 855-10 and the SEC's requirements. The update did not have a material impact on the Company's consolidated results of operations or financial position.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

Commodity Price Risk

As an independent oil and gas producer, our revenue, cash flow from operations, other income and profitability, reserve values, access to capital and future rate of growth are substantially dependent upon the prevailing prices of oil and gas. 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 oil and gas 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 our oil and gas 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, 2010, a 10% decline in oil and gas prices would have reduced our operating revenue and cash flow by approximately $5.8 million for the year; however, due to the derivative contracts that we have in place, it is unlikely that a 10% decline in commodity prices from their current levels would significantly impact our operating revenue, cash flow and net income.

Derivative Instrument Sensitivity

We account for our derivative contracts in accordance with ASC 815. The derivative instruments we utilize are based on index prices that may and often do differ from the actual oil and gas prices realized in our operations. Our derivative contract transactions do not qualify for hedge accounting as prescribed by ASC 815; therefore, fluctuations in the market value of the derivative contract are recognized in earnings during the current period.
The following table sets forth our derivative contract position as of December 31, 2010:

	Fixed Price Swap			
	Oil		Gas	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (MMbtu)	Swap Price (per MMbtu)
2011	1,035	$76.61	9,580	$6.52
2012	946	70.89	8,303	6.77
2013	705	80.79	5,962	6.84

In order to mitigate our interest rate exposure, we entered into an interest rate swap, effective August 12, 2008, to fix our floating LIBOR based debt. The two-year interest rate swap for $100 million at a fixed rate of 3.367% originally expired on August 12, 2010. The interest rate swap was amended in February 2009 lowering our fixed rate to 2.95%. The interest rate swap was further amended in November 2009 lowering our fixed rate to 2.55% and extending the term through August 12, 2012.

At December 31, 2010, the aggregate fair market value of our commodity derivative contracts was a liability of approximately $2.5 million and the aggregate fair market value of our interest rate swap was a liability of approximately $3.3 million.

For the year ended December 31, 2010, we recognized a realized gain of $2.8 million and an unrealized gain of $11.4 million on our commodity derivative contracts and we recognized a realized loss of $2.3 million and an unrealized loss of $1.1 million on our interest rate swap.

Interest Rate Risk

We are subject to interest rate risk associated with borrowings under our credit facility. As of December 31, 2010, we had $136.0 million of outstanding indebtedness under our credit facility. This outstanding amount was reduced to $80.0 million after applying the proceeds of our equity offering that closed on February 1, 2011. Outstanding amounts under the credit facility bear interest at (a) the greater of (1) the reference rate announced from time to time by Société Générale, (2) the Federal Funds Rate plus 0.5%, and (3) a rate determined by Société Générale as the daily one-month LIBOR plus, in each case,

(b) 1.5%—2.75%, depending on the utilization of the borrowing base, or, if we elect, at the greater of (1) 2.0% and (2) LIBOR plus, in each case, 2.5%—3.75%, depending on the utilization of the borrowing base. At December 31, 2010, the interest rate on the revolving portion of the credit facility was 5.75%. For every percentage point that the LIBOR rate rises, our interest expense would increase by approximately $1.4 million on an annual basis, based on our outstanding indebtedness as of December 31, 2010. In order to mitigate our interest rate exposure, we entered into an interest rate swap, effective August 12, 2008, to fix our floating LIBOR based debt. The two-year interest rate swap for $100 million at a fixed rate of 3.367% originally expired on August 12, 2010. The interest rate swap was amended in February 2009 lowering our fixed rate to 2.95%. The interest rate swap was further amended in November 2009 lowering our fixed rate to 2.55% and extending the term through August 12, 2012.

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, 2010 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, 2010.

The effectiveness of our internal control over financial reporting as of December 31, 2010 has been audited by BDO USA, 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, 2010 that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None

PART III

Item 10. Directors, Executive Officers and Corporate Governance

There is incorporated in this Item 10 by reference to that portion of our definitive proxy statement for the 2011 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 Craig S. Bartlett, Jr., Franklin A. Burke, Paul A. Powell, Jr. and Brian L. Melton. 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 NASDAQ Stock Market and Item 407(a) of Regulation S-K. In addition, the board of directors has determined that Craig S. 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 our 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 NASDAQ 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 2010.

Item 11. Executive Compensation

There is incorporated in this Item 11 by reference that portion of our definitive proxy statement for the 2011 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 2011 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 2011 Annual Meeting of Stockholders which appears therein under the captions "Certain Transactions" and "Election of Directors – Director 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 2011 Annual Meeting of Stockholders which appears therein under the caption "Principal Auditor Fees and Services."

PART IV

Item 15. Exhibits and Financial Statements

(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).

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 flied on April 2, 2001).

3.6 Amended and Restated Bylaws of Abraxas. (Filed as Exhibit 3.1 to Abraxas’ Current Report on Form 8-K. on November 17, 2008).

3.7 Certificate of Designation of Series 2010 Junior Participating Preferred Stock (Filed as Exhibit 3.1 to Abraxas Current Report on Form 8-K filed on March 17, 2010.)

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).

4.3 Rights Agreement, dated March 17, 2010 by and between Abraxas and American Stock Transfer and Trust Company (Filed as Exhibit 4.1 to Abraxas Registration Statement on Form 8-A filed on March 17, 2010).

*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).

*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 10.17 to Abraxas' Annual Report on Form 10-K filed March 23, 2006).

*10.12 Abraxas Petroleum Corporation 2005 Employee Long-Term Equity Incentive Plan (Filed as Annex E to Abraxas' Proxy Statement filed on September 8, 2009).

*10.13 Form of Employee Stock Option Agreement under the Abraxas 2005 Employee Long-Term Equity Incentive Plan. (Filed as Exhibit 10.2 to Abraxas' Current Report on Form 8-K filed August 26, 2006).

10.14 Limited Liability Company Agreement of Blue Eagle Energy, LLC dated August 18, 2010. (Filed as Exhibit 10.1 to Abraxas' Current Report on Form 8-K filed August 23, 2010).

10.15 Form of Common Stock Purchase Warrant. (Filed as Exhibit 10.8 to Abraxas' Current Report on Form 8-K filed May 31, 2007).

10.16 Voting, Registration Rights and Lock-Up Agreement, dated as of June 30, 2009, by and among Abraxas Petroleum, Abraxas Energy and certain limited partners of Abraxas Energy (Filed as Exhibit 10.1 to Abraxas' Current Report on Form 8-K filed on July 2, 2009).

10.17 Form of Indemnification Agreement by and among Abraxas Energy Partners, L.P., Abraxas General Partner, LLC, and each of its officers and directors. (Filed as Exhibit 10.25 to Abraxas' Annual Report on Form 10-K filed on March 17, 2008).

10.18 Amended and Restated Credit Agreement dated as of October 5, 2009 among Abraxas Petroleum, as Borrower, the lenders party thereto and Société Générale, as Administrative Agent and as Issuing Lender (Filed as Exhibit 10.1 to Abraxas' Current Report on Form 8-K filed on October 7, 2009).

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. (Filed as Exhibit 18.1 to Abraxas' Annual Report on Form 10-K/A Number 2 filed on August 20, 2008).

21.1 Subsidiaries of Abraxas. (Filed as Exhibit 21.1 to Abraxas' Annual Report on Form 10-K filed on March 17, 2010).

62

23.1 Consent of BDO USA, LLP. (Filed as Exhibit 23.1 to Abraxas's Annual Report on Form 10-K filed on March 16, 2011).

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 as Exhibit 32.1 to Abraxas' Annual Report on Form 10-K filed on March 16, 2011).

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 as Exhibit 32.2 to Abraxas' Annual Report on Form 10-K filed on March 16, 2011).

99.1 Report of DeGolyer and MacNaughton. (Filed as Exhibit 99.1 to Abraxas' Annual Report on Form 10-K filed on March 16, 2011).

* Management Compensatory Plan or Agreement.

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 President and Principal Executive Officer	By: / s/Barbara M. Stuckey Vice President and Principal Financial Officer	By: /s/ G. William Krog, Jr. Principal Accounting Officer

DATED: October 13, 2011

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 Robert L.G. Watson	Chairman of the Board, President (Principal Executive Officer) and Director	October 13, 2011
/s/ Barbara M. Stuckey Barbara M. Stuckey	Vice President, CFO (Principal Financial Officer)	October 13, 2011
/s/G. William Krog, Jr. G. William Krog, Jr.	Chief Accounting Officer (Principal Accounting Officer)	October 13, 2011
/s/ Craig S. Bartlett, Jr. Craig S. Bartlett, Jr.	Director	October 13, 2011
/s/ Franklin A. Burke Franklin A. Burke	Director	October 13, 2011
/s/ Harold D. Carter Harold D. Carter	Director	October 13, 2011
/s/ Ralph F. Cox Ralph F. Cox	Director	October 13, 2011
/s/ Dennis E. Logue bDennis E. Logue	Director	October 13, 2011
/s/ Paul A. Powell, Jr. Paul A. Powell, Jr.	Director	October 13, 2011
/s/Brian L. Melton Brian L. Melton	Director	October 13, 2011
/s/Edward P. Russell Edward P. Russell	Director	October 13, 2011