ABRAXAS PETROLEUM CORP
Form 10-Q
August 16, 2010

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

FORM 10-Q

(Mark One)
x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE QUARTERLY PERIOD ENDED JUNE 30, 2010

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE TRANSITION PERIOD FROM ______ TO ______

COMMISSION FILE NUMBER: 001-16071

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

Nevada	74-2584033
(State of Incorporation)	(I.R.S. Employer Identification No.)

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

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

Not Applicable
(Former name, former address and former fiscal year, if changed since last report)

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 the filing requirements for the past 90 days.

Yes x No o

Indicate by check mark whether 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 whether the registrant is a large accelerated filer, an accelerated filer, 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	o	Accelerated filer	o
Non-accelerated filer	x	Smaller reporting company	o
(Do not mark if a 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

The number of shares of the issuer's common stock outstanding as of August 13, 2010 was:

Class	Shares Outstanding
Common Stock, $.01 Par Value	76,380,205

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Forward-Looking Information

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

- our success in development, exploitation and exploration activities;
- our ability to 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;
- our ability to raise equity capital or incur additional indebtedness;
- political and economic conditions in oil producing countries, especially those in the Middle East;
- price and availability of alternative fuels;
- our restrictive debt covenants;
- our acquisition and divestiture activities;
- weather conditions and events;
- the proximity, capacity, cost and availability of pipelines and other transportation facilities;
- results of our hedging activities; and
- other factors discussed elsewhere in this document.

In addition to these factors, important factors that could cause actual results to differ materially from our expectations (“Cautionary Statements”) are disclosed under “Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2009. All subsequent written and oral forward-looking statements attributable to us, or persons acting on our behalf, are expressly qualified in their entirety by the Cautionary Statements.

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GLOSSARY OF TERMS

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

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

Terms used to describe quantities of oil and gas:

"Bbl" – barrel or barrels.

"Bcf" – billion cubic feet of gas.

"Bcfe" – billion cubic feet of gas equivalent.

"Boe" – barrels of oil equivalent.

"Boepd" – barrels of oil equivalent per day.

"MBbl" – thousand barrels.

"MBoe" – thousand barrels of oil equivalent.

"Mcf" – thousand cubic feet of gas.

"Mcfe" – thousand cubic feet of gas equivalent.

"MMBbls" – million barrels.

"MMBoe" – million barrels of oil equivalent.

"MMbtu" – million British Thermal Units.

"MMcf" – million cubic feet of gas.

"MMcfe" – million cubic feet of gas equivalent.

"MMcfepd" – million cubic feet of gas equivalent per day.

"MMcfpd" – million cubic feet of gas per day.

Terms used to describe our interests in wells and acreage:

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

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

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

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

"Gross acres" refer to the number of acres in which we own a working interest.

"Gross well" is a well in which we own an interest.

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

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

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

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

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

"Proved reserves" or "reserves" Proved oil and gas reserves are those quantities of oil and gas, 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" 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" Proved oil and gas reserves that are developed behind pipe, shut-in 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" 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" Proved 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 which together with proved reserves, are as likely as not to be recovered.

"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."

ABRAXAS PETROLEUM CORPORATION

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PART I
FINANCIAL INFORMATION

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PART I
FINANCIAL INFORMATION

Item 1. Financial Statements

Abraxas Petroleum Corporation
Condensed Consolidated Balance Sheets
(in thousands)

	June 30, 2010 (Unaudited)	December 31, 2009
Assets		
Current assets:		
Cash and cash equivalents	$ 2,594	$ 1,861
Accounts receivable, net:		
Joint owners	943	865
Oil and gas production	6,886	7,873
Other	791	31
	8,620	8,769
Derivative asset – current	4,209	325
Other current assets	405	514
Total current assets	15,828	11,469
Property and equipment:		
Oil and gas properties, full cost method of accounting:		
Proved	451,616	454,142
Unproved properties excluded from depletion	—	—
Other property and equipment	11,356	11,259
Total	462,972	465,401
Less accumulated depreciation, depletion, and amortization	(317,906)	(309,245)
Total property and equipment – net	145,066	156,156
Deferred financing fees, net	4,621	5,804
Derivative asset – long-term	7,480	2,253
Other assets	864	554
Total assets	$ 173,859	$ 176,236

See accompanying notes to condensed consolidated financial statements (unaudited)

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Abraxas Petroleum Corporation
Condensed Consolidated Balance Sheets (continued)
(in thousands, except share data)

	June 30, 2010 (Unaudited)	December 31, 2009
Liabilities and Stockholders' Deficit		
Current liabilities:		
Accounts payable	$6,205	$8,773
Oil and gas production payable	3,313	3,606
Accrued interest	392	563
Other accrued expenses	1,480	770
Derivative liability – current	4,793	7,047
Current maturities of long-term debt	146	8,141
Total current liabilities	16,329	28,900
Long-term debt, excluding current maturities	144,317	143,592
Derivative liability – long-term	4,669	11,781
Future site restoration	9,634	10,326
Total liabilities	174,949	194,599
Stockholders' Deficit		
Abraxas Petroleum Corporation stockholders' deficit:		
Preferred stock, par value $.01, authorized 1,000,000 shares; -0- issued and outstanding	—	—
Common Stock, par value $.01 per share-authorized 200,000,000 shares;issued and outstanding 76,370,205 and 76,231,751	764	762
Additional paid-in capital	183,494	182,647
Accumulated deficit	(185,491)	(201,974)
Accumulated other comprehensive income	143	202
Total stockholders' deficit	(1,090)	(18,363)
Total liabilities and stockholders' deficit	$173,859	$176,236

See accompanying notes to condensed consolidated financial statements (unaudited)

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Abraxas Petroleum Corporation
Condensed Consolidated Statements of Operations
(Unaudited)
(in thousands, except per share data)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Revenue:				
Oil and gas production revenues	$14,646	$12,119	$30,509	$22,715
Rig revenues	259	247	520	500
Other	4	2	6	3
	14,909	12,368	31,035	23,218
Operating costs and expenses:				
Lease operating and production taxes	6,565	5,985	12,854	11,854
Depreciation, depletion, and amortization	4,433	4,507	8,674	8,994
Rig operations	193	211	390	399
General and administrative (including stock-based compensation of $537, $329, $847, and $596)	2,191	1,601	4,332	3,730
	13,382	12,304	26,250	24,977
Operating income (loss)	1,527	64	4,785	(1,759)
Other (income) expense:				
Interest income	(2)	(6)	(4)	(11)
Interest expense	2,252	3,051	4,586	5,607
Financing fees	—	—	—	362
Amortization of deferred financing fee	513	374	1,322	586
(Gain) loss on derivative contracts (unrealized $(5,941), $20,889, $(17,636) and $14,459)	(6,550)	14,560	(17,527)	1,695
Other	14	2,208	(75)	2,229
	(3,773)	20,187	(11,698)	10,468
Consolidated net income (loss)	5,300	(20,123)	16,483	(12,227)
Net loss attributable to non-controlling interest	—	10,091	—	6,645
Net income (loss)	$5,300	$(10,032)	$16,483	$(5,582)
Net income (loss) per common share – basic	$0.07	$(0.20)	$0.22	$(0.11)
Net income (loss) per common share – diluted	$0.07	$(0.20)	$0.21	$(0.11)

See accompanying notes to condensed consolidated financial statements (unaudited)

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Abraxas Petroleum Corporation
Condensed Consolidated Statements of Cash Flows
(Unaudited)
(in thousands)

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
Operating Activities		
Net income (loss)	$16,483	$(12,227)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Change in derivative fair value	(18,477)	14,577
Depreciation, depletion, and amortization	8,674	8,994
Amortization of deferred financing fees	1,322	586
Accretion of future site restoration	271	281
Stock-based compensation	847	596
Other non-cash expenses	24	123
Registration fees previously capitalized	—	2,207
Changes in operating assets and liabilities:		
Accounts receivable	149	579
Other	(260)	135
Accounts payable and accrued expenses	(3,285)	(6,395)
Net cash provided by operating activities	5,748	9,456
Investing Activities		
Capital expenditures, including purchases and development of properties	(8,592)	(7,510)
Proceeds from disposition of oil and gas properties	11,008	—
Net cash provided by (used in) investing activities	2,416	(7,510)
Financing Activities		
Proceeds from long-term borrowings	2,000	5,924
Payments on long-term borrowings	(9,270)	(1,988)
Partnership distributions	—	(2,257)
Deferred financing fees	(139)	(3,242)
Exercise of stock options	47	49
Other	(69)	(566)
Net cash used in financing activities	(7,431)	(2,080)
Increase in cash	733	(134)
Cash, at beginning of period	1,861	1,924
Cash, at end of period	$2,594	$1,790

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Abraxas Petroleum Corporation
Condensed Consolidated Statements of Cash Flows (continued)
(Unaudited)
(in thousands)

	Six Months Ended June 30, 2010	2009
Supplemental disclosure of cash flow information:		
Interest paid	$4,314	$5,402
Non-Cash Investing Activities:		
Asset retirement obligation cost and liabilities	$(73)	$(23)
Asset retirement obligations associated with property acquisitions and dispositions	$(849)	$12

See accompanying notes to condensed consolidated financial statements (unaudited)

Abraxas Petroleum Corporation
Notes to Condensed Consolidated Financial Statements
(Unaudited)
(tabular amounts in thousands, except per share data)

Note 1. Basis of Presentation

The accounting policies followed by Abraxas Petroleum Corporation and its subsidiaries (the “Company”) are set forth in the notes to the Company’s audited consolidated financial statements in the Annual Report on Form 10-K filed for the year ended December 31, 2009. Such policies have been continued without change. Also, refer to the notes to those financial statements for additional details of the Company’s financial condition, results of operations, and cash flows. All material items included in those notes have not changed except as a result of normal transactions in the interim, or as disclosed within this report. The accompanying interim consolidated financial statements have not been audited by our independent registered public accountants, but in the opinion of management, reflect all adjustments necessary for a fair presentation of the financial position and results of operations. Any and all adjustments are of a normal and recurring nature. Although management believes the unaudited interim related disclosures in these consolidated financial statements are adequate to make the information presented not misleading, certain information and footnote disclosures normally included in annual audited consolidated financial statements prepared in accordance with accounting principles generally accepted in the United States of America have been condensed or omitted pursuant to the rules and regulations of the Securities and Exchange Commission. The results of operations and the cash flows for the periods ended June 30, 2010 are not necessarily indicative of the results to be expected for the full year. The condensed consolidated financial statements included herein should be read in conjunction with the consolidated audited financial statements and the notes thereto included in the Company’s Annual Report on Form 10-K for the year ended December 31, 2009.

Consolidation Principles

The terms “Abraxas” or “Abraxas Petroleum” refer to Abraxas Petroleum Corporation and its subsidiaries other than Abraxas Energy Partners, L.P., which we refer to as “Abraxas Energy Partners” or the “Partnership,” and its subsidiary, Abraxas Operating, LLC, which we refer to as “Abraxas Operating” and the terms “we,” “us,” “our” or the “Company” refer Abraxas Petroleum Corporation and all of its consolidated subsidiaries including Abraxas Energy Partners and Abraxas Operating through October 5, 2009. The operations of Abraxas Petroleum and the Partnership were consolidated for financial reporting purposes through October 5, 2009, with the interest of the 51.8% non-controlling owners of the Partnership presented as non-controlling interest. Abraxas owned the remaining 48.2% of the Partnership interests. The Company determined that based on its control of the general partner of the Partnership, this 48.2% owned entity should be consolidated for financial reporting purposes. As discussed below, on October 5, 2009, the Partnership was merged into Abraxas Petroleum Corporation.

On June 30, 2009, Abraxas Petroleum and Abraxas Energy Partners signed an Agreement and Plan of Merger, which we refer to as the Original Merger Agreement, pursuant to which Abraxas Energy Partners agreed to merge with and into Abraxas Petroleum with Abraxas Petroleum surviving and on July 17, 2009, Abraxas Petroleum and Abraxas Energy Partners signed an Amended and Restated Agreement and Plan of Merger, which we refer to as the Merger Agreement, pursuant to which Abraxas Energy Partners agreed to merge with and into Abraxas Merger Sub, LLC, which we refer to as Merger Sub, with Merger Sub surviving the merger as a wholly-owned subsidiary of Abraxas Petroleum. We refer to this merger as the Merger. Under the terms of the Merger Agreement, at the effective time of the Merger on October 5, 2009, which we refer to as the Effective Time, each common unit of Abraxas Energy Partners not owned by Abraxas Petroleum and its subsidiaries was converted into the right to receive 4.25 shares of Abraxas Petroleum common stock. We issued a total of 26,174,061 shares of our common stock in the Merger, including 420,552 shares of restricted common stock issued in exchange for restricted units and phantom units of

Abraxas Energy Partners under the Abraxas Petroleum Corporation 2005 Employee Long-Term Equity Incentive Plan, or LTIP.

The Company consolidates its financial statements based on the guidance of Accounting Standards Codification ("ASC") 810. ASC 810 establishes accounting and reporting standards for (1) ownership interests in subsidiaries held by others, (2) the amount of consolidated net income attributable to the controlling and non-controlling interests, (3) changes in the controlling ownership interest, (4) the valuation of retained non-controlling equity investments when a subsidiary is deconsolidated and (5) disclosures that clearly identify and distinguish between the interests of the controlling and non-controlling owners. The adoption of ASC 810 resulted in changes to our presentation for non-controlling interests and did not have a material impact on the Company's results of operations and financial condition.

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In accordance with generally accepted accounting principles in effect prior to the adoption of ASC 810, which codifies SFAS 160, when cumulative losses applicable to the non-controlling interest exceed the non-controlling interest equity capital in the entity, such excess and any further losses applicable to the non-controlling interest were charged to the earnings of the controlling interest. Future earnings were recognized by the non-controlling interest and were credited to the controlling interest (Abraxas) to the extent of such losses previously absorbed.

Use of Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as of the date of the financial statements and reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Equity-based Compensation

Stock Options

The Company currently utilizes a standard option-pricing model (i.e., Black-Scholes) to measure the fair value of stock options granted to employees. For the three and six months ended June 30, 2010 and 2009, the Company recognized expense of $444,000, $637,000, $270,000 and $450,000 respectively, related to stock options.

The following table summarizes the stock option activities for the six months ended June 30, 2010.

	Shares	Weighted Average Option Exercise Price Per Share	Weighted Average Grant Date Fair Value Per Share	Aggregate Intrinsic Value
Outstanding, December 31, 2009	4,090	$ 2.18	$ 1.59	$ 5,480
Granted	949	$ 2.11	$ 1.60	1,516
Exercised	(170)	$ 0.92	$ 0.64	(109)
Expired or canceled	(7)	$ 3.46	$ 2.05	(14)
Outstanding, June 30, 2010	4,862	$ 2.21	$ 1.42	$ 6,873

The following table shows the weighted average assumptions used in the Black-Scholes valuation of the fair value of option grants for the six months ended June 30, 2010.

Expected dividend yield	0	%
Volatility	83.99	%
Risk free interest rate	2.87	%
Expected life	8.97	Years
Fair value of options granted (in thousands)	$1,519	
Weighted average grant date fair value per share of options granted	$1.60	

Additional information related to options at June 30, 2010 and December 31, 2009 is as follows:

	June 30,

		December 31,
	2010	2009
Options exercisable	1,963	1,808

As of June 30, 2010, there was approximately $3.0 million of unamortized compensation expense related to outstanding options that will be recognized in 2010 through 2014.

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Restricted Stock Awards

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 was determined using the market price on the grant date. Compensation expense is recorded over the applicable restricted stock vesting periods.

A summary of the Company's restricted stock activity for the six months ended June 30, 2010 is presented in the following table:

	Number of Shares	Weighted Average Grant Date Fair Value (per share)
Unvested December 31, 2009	549	$ 2.05
Granted	10	2.02
Vested/Released	(119)	1.81
Forfeited	(6)	1.19
Unvested June 30, 2010	434	$ 2.13

For the three and six months ended June 30, 2010 and 2009, the Company incurred $93,000, $210,000, $37,000 and $75,000, respectively, in stock-based compensation expense relating to restricted stock. As of June 30, 2010, there was approximately $643,000 of unamortized compensation expense related to outstanding restricted shares that will be recognized in 2010 through 2014.

Restricted Unit Awards

Restricted unit awards are awards of Partnership units 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 unit was determined using the implied market price on the grant date. The implied market price was determined by comparing the average trading yields of comparable publicly-traded master limited partnerships to the distribution paid or declared by the Partnership prior to the grant date. Compensation expense is recorded over the applicable restricted unit vesting periods.

For the three and six months ended June 30, 2009, the Partnership incurred $22,000 and $46,000, respectively, in equity-based compensation expense relating to restricted units. In connection with the closing of the Merger, restricted unit awards were converted into restricted stock awards of the Company.

Phantom Units

On January 31, 2008, in connection with the closing of the St. Mary acquisition, the Partnership awarded phantom units with distribution equivalency rights under its long-term incentive plan to certain key employees of Abraxas Petroleum.

For the three and six months ended June 30, 2009, the Partnership incurred $0 and $25,000, respectively, in equity based compensation expense relating to phantom units. In connection with the closing of the Merger, outstanding phantom unit awards were converted into restricted stock awards of the Company.

Oil and Gas Properties

The Company follows the full cost method of accounting for oil and gas properties. Under this method, all direct costs and certain indirect costs associated with acquisition of properties and successful as well as unsuccessful exploration and development activities are capitalized. Depreciation, depletion, and amortization of capitalized oil and gas properties and estimated future development costs, excluding unproved properties, are based on the unit-of-production method based on proved reserves. Net capitalized costs of oil and gas properties, less related deferred taxes, are limited to the lower of unamortized cost or the cost ceiling, defined as the sum of the present value of estimated future net revenues from proved reserves based on unescalated prices discounted at 10 percent, plus the cost of properties not

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being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. The Company does not have any properties that are being excluded from amortization. Costs in excess of the present value of estimated future net revenues as discussed above are charged to proved property impairment expense. No gain or loss is recognized upon sale or disposition of oil and gas properties, except in unusual circumstances. We apply the full cost ceiling test on a quarterly basis on the date of the latest balance sheet presented.

The estimates of our reserves as of December 31, 2009, 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 un-weighted first-day-of-the-month average oil and gas prices for the year ended December 31, 2009. The average realized sales prices as of such date used for purposes of such estimates were $3.42 per Mcf of gas and $55.05 per Bbl of oil. As of December 31, 2009 and June 30, 2010, our net capitalized costs of oil and gas properties did not exceed the present value of our estimated proved reserves.

Restoration, Removal and Environmental Liabilities

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

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

The Company accounts for asset retirement obligations based on the guidance of ASC 410 (formerly FASB 143) which addresses accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. ASC 410 requires that the fair value of a liability for an asset's retirement obligation be recorded in the period in which it is incurred and the corresponding cost capitalized by increasing the carrying amount of the related long-lived asset. The liability is accreted to its then present value each period, and the capitalized cost is depreciated over the estimated useful life of the related asset. For all periods presented, we have included estimated future costs of abandonment and dismantlement in our full cost amortization base and amortize these costs as a component of our depletion expense in the accompanying consolidated financial statements.

The following table summarizes the Company’s asset retirement obligation transactions for the six months ended June 30, 2010 and the year ended December 31, 2009:

	June 30, 2010	December 31, 2009
Beginning asset retirement obligation	$10,326	$9,959
Settled	(41)	(113)
Revisions	(73)	(80)
New wells placed on production and other	25	91
Deletions related to property disposals	(874)	(89)
Accretion expense	271	558

Ending asset retirement obligation	$9,634	$10,326

Working Capital (Deficit)

At June 30, 2010, our current liabilities of approximately $16.3 million exceeded our current assets of $15.8 million resulting in a working capital deficit of $500,000. This compares to a working capital deficit of approximately $17.4 million at December 31, 2009. Current liabilities at June 30, 2010 primarily consisted of the current portion of derivative liabilities of $4.8 million, trade payables of $6.2 million, revenues due third parties of $3.3 million, and other accrued liabilities of $1.5 million.

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Recently Issued Accounting Pronouncements

Derivatives and Hedging. In March 2010, the FASB issued an amendment to previously issued guidance regarding embedded credit derivatives. This amendment provides clarification of the scope exception for embedded credit derivatives that transfer credit risk only in the form of subordination of one financial instrument to another. All entities that enter into contracts containing an embedded credit derivative feature related to the transfer of credit risk that is not only in the form of subordination of one financial instrument to another will be affected by the amendment because the amendment clarifies that the embedded credit derivative scope exception per the guidance does not apply to such contracts. This amended guidance is effective at the beginning of the first fiscal quarter beginning after June 15, 2010. Early adoption is permitted at the beginning of the first fiscal quarter beginning after the issuance of this amendment. The Company is currently evaluating the impact of this guidance on its operating results, financial position and cash flows.

Fair Value Measurements. In January 2010, the FASB issued authoritative guidance related to improving disclosures about fair value measurements. This guidance requires separate disclosures of the amounts of transfers in and out of Level 1 and Level 2 fair value measurements and a description of the reason for such transfers. In the reconciliation for Level 3 fair value measurements using significant unobservable inputs, information about purchases, sales, issuances and settlements shall be presented separately. These disclosures are required for interim and annual reporting periods effective January 1, 2010, except for the disclosures related to the purchases, sales, issuances and settlements in the roll forward activity of Level 3 fair value measurements, which are effective on January 1, 2011. This guidance was adopted on January 1, 2010 for Level 1 and Level 2 fair value measurements and did not impact the Company's operating results, financial position or cash flows but did require additional disclosures regarding the fair value of financial instruments. See Item 1. "Financial Statements, Note 6 – Fair Value."

Note 2. Income Taxes

The Company records income taxes using the liability method. Under this method, deferred tax assets and liabilities are determined based on differences between financial reporting and tax basis of assets and liabilities and are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse.

For the three and six months ended June 30, 2010 and 2009, there was no current or deferred income tax expense or benefit due to losses and/or loss carryforwards and valuation allowance which have been recorded against such benefits.

The Company accounts for uncertain tax positions under the 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 three and six months ended June 30, 2010 and 2009. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of June 30, 2010, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years from 2000 through 2009 remain open to examination by the tax jurisdictions to which the Company is subject.

Note 3. Long-Term Indebtedness

Long-term debt consisted of the following:

	June 30, 2010	December 31, 2009
Credit facility – Term portion	$—	$8,000
Credit facility – Revolving portion	139,300	138,500
Real estate lien note	5,163	5,233

	144,463	151,733
Less current maturities	(146)	(8,141)
	$144,317	$143,592

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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. In connection with the Merger, we borrowed $145.0 million under the credit facility, of which $135.0 million was borrowed under the revolving portion and $10.0 million was borrowed under the term loan portion. As of June 30, 2010, $139.3 million was outstanding under the revolving portion of the credit facility. The term portion of the credit facility was paid in full on March 30, 2010.

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 $145.0 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 $145.0 million was determined based upon our reserve report dated December 31, 2009. 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 June 30, 2010, the interest rate on the revolving portion of the credit facility was 5.75%.

We also borrowed $10.0 million under the term loan portion of the credit facility at the closing of the Merger. Outstanding amounts under the term loan 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) 4.75%, or, if we elect, at the greater of (1) 2.0% and (2) LIBOR plus, in each case, 5.75%. The term portion of the credit facility was paid in full on March 30, 2010.

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 4.50 to 1.00 for the quarter ending September 30, 2009 through the quarter ending September 30, 2010, and not more than 4.00 to 1.00 thereafter. 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 (which relates to derivative instruments and hedging activities and was previously referred to as SFAS 133) and ASC 410-20 (which relates to asset retirement obligations and was previously referred to as SFAS 143) 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

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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 (which relates to stock-based compensation and was previously referred to as SFAS 123R), 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 June 30, 2010.

As of June 30, 2010, the current ratio was 1.52 to 1.00, the interest coverage ratio was 4.88 to 1.00 and the total debt to EBITDAX ratio was 2.34 to 1.00.

The credit facility also required that we enter into hedging arrangements for specified volumes, which equate to approximately 85% of the estimated oil and gas production from our net proved developed producing reserves through December 31, 2012 and 70% 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, the Company 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 its 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 June 30, 2010, $5.2 million was outstanding on the note.

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Note 4. Earnings (Loss) Per Share

The following table sets forth the computation of basic and diluted earnings (loss) per share:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
Numerator:				
Net income (loss) available to common stockholders	$5,300	$(10,032)	$16,483	$(5,582)
Denominator:				
Denominator for basic earnings (loss) per share - weighted-average shares	75,850	49,564	75,824	49,628
Effect of dilutive securities:				
Stock options and warrants	1,298	—	1,228	—
Denominator for diluted earnings (loss) per share - adjusted weighted-average shares and assumed conversions	77,148	49,564	77,052	49,628
Net income (loss) per common share – basic	$0.07	$(0.20)	$0.22	$(0.11)
Net income (loss) per common share – diluted	$0.07	$(0.20)	$0.21	$(0.11)

For the three and six months ended June 30, 2009 none of the shares issuable in connection with stock options or warrants are included in diluted shares. Inclusion of these shares would be antidilutive due to losses incurred in the periods. Had there not been losses in the periods, dilutive shares would have been 321,286 shares and 330,226 shares for the three and six months ended June 30, 2009.

Note 5. Hedging Program and Derivatives

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. These variations often result in a lack of adequate correlation to enable these derivate instruments to qualify for hedge accounting rules as prescribed by ASC 815. Accordingly, we do not attempt to account for our derivative instruments as cash flow hedges for financial reporting purposes and instead record their fair value on the balance sheet with adjustments to the carrying value of the instruments being recognized as a gain or loss on derivative contracts in the current period.

Our credit facility required that we enter into hedging arrangements for specified volumes, which equated to approximately 85% of the estimated oil and gas production from our net proved developed producing reserves through December 31, 2012 and 70% for 2013. We satisfied this requirement by assuming all of the Partnership's derivative contracts in connection with the Merger.

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The following table sets forth our derivative contract position at June 30, 2010:

	Fixed Price Swap			
	Oil		Gas	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (MMBtu)	Swap Price (per MMBtu)
2010	1,158	$73.28	11,258	$5.73
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 June 30, 2010, the aggregate fair market value of our commodity derivative contracts was an asset of approximately $5.8 million, based on average NYMEX future strip prices as of June 30, 2010 of $80.39 per Bbl and $5.48 per MMbtu.

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 arrangement for $100 million at a fixed rate of 3.367% originally set to expire on August 12, 2010. This 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. The fair value of this interest rate swap was a liability of $3.6 million at June 30, 2010.

The following table illustrates the impact of derivative contracts on the Company's balance sheet:

	June 30, 2010		December 31, 2009	
	Balance Sheet Location	Fair Value (thousands)	Balance Sheet Location	Fair Value (thousands)
NYMEX-based fixed price derivative contracts	Derivative asset - current	$ 4,209	Derivative asset - current	$ 325
NYMEX-based fixed price derivative contracts	Derivative asset – long-term	$ 7,480	Derivative asset – long-term	$ 2,253
NYMEX-based fixed price derivative contracts	Derivative liability - current	$ 1,175	Derivative liability - current	$ 4,791
NYMEX-based fixed price derivative contracts	Derivative liability – long-term	$ 4,669	Derivative liability – long-term	$ 11,781
Interest rate swap	Derivative liability - current	$ 3,618	Derivative liability - current	$ 2,256

Gains and losses from derivative activities are reflected as "(Gain) loss on derivative contracts" in the accompanying Condensed Consolidated Statement of Operations.

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Note 6. Fair Value

On January 1, 2009, the Company adopted the provisions of ASC 820-10 (formerly SFAS 157) for nonfinancial assets and liabilities measured at fair value on a non-recurring basis. As it relates to the Company, the adoption applies to certain nonfinancial assets and liabilities as may be acquired in a business combination and thereby measured at fair value, impaired oil and gas property assessments and the initial recognition of asset retirement obligations for which fair value is used.

The adoption of ASC 820-10 did not have material impact on the Company's consolidated financial statements or its disclosures with respect to the initial recognition of asset retirement obligations for the year ended December 31, 2009 or the six months ended June 30, 2010. These estimates are derived from historical costs as well as management's expectation of future cost environments. As there is no corroborating market activity to support the assumptions used, Abraxas has designated these liabilities as Level 3.

Fair Value Hierarchy—ASC 820-10 establishes a three-level valuation hierarchy for disclosure of fair value measurements. The valuation hierarchy categorizes assets and liabilities measured at fair value into one of three different levels depending on the observability of the inputs employed in the measurement. The three levels are defined as follows:

- Level 1 – inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.

- Level 2- inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.

- Level 3 - inputs to the valuation methodology are unobservable and significant to the fair value measurement.

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. The Company is further required to assess the creditworthiness of the counter-party to the derivative contract. The results of the assessment of non-performance risk, based on the counter-party's credit risk, could result in an adjustment of the carrying value of the derivative instrument. The following tables present information about the Company's assets and liabilities measured at fair value as of December 31, 2009 and June 30, 2010, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value:

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of December 31, 2009
Assets:				
Investment in common stock	$208	$—	$ —	$208
NYMEX Fixed Price Derivative contracts	—	2,578	—	2,578
Total Assets	$208	$2,578	$ —	$2,786
Liabilities:				
NYMEX Fixed Price Derivative contracts	$—	$16,571	$ —	$16,571

Interest Rate Swaps	—	—	2,256	2,256
Total Liabilities	$—	$16,571	$ 2,256	$18,827

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	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of June 30, 2010
Assets				
Investment in common stock	$192	$—	$ —	$192
NYMEX Fixed Price Derivative contracts	—	11,689	—	11,689
Total assets	$192	$11,689	$ —	$11,881
Liabilities				
NYMEX Fixed Price Derivative contracts	$—	$5,844	$ —	$5,844
Interest Rate Swaps	—	—	3,618	3,618
Total Liabilities	$—	$5,844	$ 3,618	$9,462

The Company has an investment in a former subsidiary consisting of shares of common stock. The stock is actively traded on the Toronto Stock Exchange. This investment is valued at its quoted price as of June 30, 2010 in US dollars. Accordingly this investment is characterized as Level 1.

The Company's derivative contracts consist of NYMEX-based fixed price commodity swaps and interest rate swaps, which are not traded on a public exchange. The NYMEX-based fixed price derivative contracts are indexed to NYMEX futures contracts, which are actively traded, for the underlying commodity, and are commonly used in the energy industry. A number of financial institutions and large energy companies act as counter-parties to these type of derivative contracts. As the fair value of these derivative contracts is based on a number of inputs, including contractual volumes and prices stated in each derivative contract, current and future NYMEX commodity prices, and quantitative models that are based upon readily observable market parameters that are actively quoted and can be validated through external sources, we have characterized these derivative contracts as Level 2.

In August 2008, the Company entered into a two-year interest rate swap. The notional amount was $100.0 million for the first year and $50.0 million for the second year. The Company will pay interest at 3.367% and be paid on a floating LIBOR rate. The interest rate swap was amended in February 2009 and increased the notional amount in the second year to $100.0 million and reduced the overall interest rate to 2.95%. The interest rate swap was further amended in November 2009 reducing the interest rate to 2.55% and extending the term through August 12, 2012. As there is no actively traded market for this type of swap and no observable market parameters, these derivative contracts are classified as Level 3.

Additional information for the Company's recurring fair value measurements using significant unobservable inputs (Level 3 inputs) for the three and six months ended June 30, 2010 is as follows:

	Derivative Assets and (Liabilities) - net	
	Three Months Ended	Six Months Ended June 30, 2010

	June 30, 2010	
Balance Beginning of period	$(2,996)	$(2,256)
Total realized and unrealized losses included in change in net liability	(1,180)	(2,515)
Settlements during the period	558	1,153
Balance June 30, 2010	$(3,618)	$(3,618)

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Note 7. Contingencies – Litigation

From time to time, the Company is involved in litigation relating to claims arising out of its operations in the normal course of business. At June 30, 2010, the Company was not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on its operations.

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Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following is a discussion of our 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, included in our Annual Report on Form 10-K filed for the year ended December 31, 2009 filed with the Securities and Exchange Commission on March 17, 2010. The terms "Abraxas" or "Abraxas Petroleum" refer to Abraxas Petroleum Corporation and its subsidiaries other than Abraxas Energy Partners, L.P., which we refer to as "Abraxas Energy Partners" or the "Partnership", and its subsidiary, Abraxas Operating, LLC, which we refer to as "Abraxas Operating" and the terms "we", "us", "our" or the "Company" refer to Abraxas Petroleum Corporation and all of its consolidated subsidiaries including Abraxas Energy Partners and Abraxas Operating for the period prior to October 5, 2009. The operations of Abraxas Petroleum and the Partnership were consolidated for financial reporting purposes for periods prior to October 5, 2009, with the interest of the 51.8% non-controlling owners of the Partnership presented as non-controlling interest. Abraxas owned the remaining 48.2% of the Partnership interests. The Company has determined that based on its control of the general partner of the Partnership, this 48.2% owned entity should be consolidated for financial reporting purposes. On October 5, 2009, the Partnership was merged into Abraxas Petroleum Corporation.

Critical Accounting Policies

There have been no changes from the Critical Accounting Policies described in our Annual Report on Form 10-K for the year ended December 31, 2009.

General

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

Factors Affecting Our Financial Results

While we have attained positive net income in two of the five years ended December 31, 2009, we sustained a loss in the year ended December 31, 2009 and we cannot assure you that we can achieve positive operating income and net income in the future. 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;
- 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;

- interest rates on borrowings; and
- the level and success of exploration and development activity.

Commodity Prices and Hedging Activities.

The results of our operations are highly dependent upon the prices received for our 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

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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.

During the first six months of 2010, the price of oil increased significantly from the levels experienced during the first six months of 2009. During the first six months of 2010, the New York Mercantile (NYMEX) price for West Texas Intermediate (WTI) averaged \$78.46 per barrel as compared to \$51.59 per barrel during the first six months of 2009. During the first six months of 2010, the average price of gas increased slightly from the levels experienced during the first six months of 2009. NYMEX Henry Hub spot prices for gas averaged \$4.72 per MMBtu for the first six months of 2010 compared to \$4.12 for the same period of 2009. Prices closed the period at \$75.63 per Bbl of oil and \$4.55 per MMBtu of gas. 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 the first six months of 2010, differentials averaged \$7.31 per Bbl of oil and \$0.36 per Mcf of gas as compared to \$7.71 per Bbl of oil and \$0.99 per Mcf of gas during the first six months of 2009. In the first six months of 2010, we experienced lower gas differentials compared to the same period of 2009 due to an increased percentage of our gas production coming from higher BTU gas wells in addition to an overall decline in basis differentials for gas. Oil differentials increased due to overall increases in basis differentials for oil across all of our operating areas. 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 also required us to enter into hedging arrangements for specified volumes, which equated to approximately 85% of the estimated oil and gas production from our net proved developed producing reserves through December 31, 2012 and 70% 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 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. In the first six months of 2010, we incurred a realized gain of \$1.0 million and an unrealized gain of \$19.0 million. In the first six months of 2009, we incurred a realized gain of \$14.0 million and an unrealized loss of \$14.8 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 June 30, 2010:

	Fixed Price Swap			
	Oil		Gas	
Contract Periods	Daily Volume (Bbl)	Swap Price	Daily Volume (MMBtu)	Swap Price
2010	1,158	\$73.28	11,258	\$5.73
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 June 30, 2010, the aggregate fair market value of our oil and gas derivative contracts was an asset of approximately $5.8 million, based on average NYMEX future strip prices as of June 30, 2010 of $80.39 per Bbl and $5.48 per MMbtu.

Production Volumes. Because 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, our reserves and production will decrease. Based on the reserve information set forth in our reserve estimates as of December 31, 2009, our average annual estimated

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decline rate for net proved developed producing reserves is 13% during the first five years, 8% in the next five years, and approximately 7% thereafter. These rates of decline are estimates and actual production declines could be materially higher. While we have had some success in finding, acquiring and developing additional reserves, we have not always been able to fully replace the production volumes lost from natural field declines and prior property sales. Our ability to acquire or find additional reserves in the near future will be dependent, in part, upon the amount of available funds for acquisition, exploration and development projects. We had capital expenditures of $8.6 million during the first six months of 2010. We have a capital budget for 2010 of approximately $30.0 million. The final amount of our capital expenditures for 2010 will depend on our success rate, production levels, the availability of capital and commodity prices. Additionally, due to the increased number of drilling rigs running in the Williston Basin 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.

Availability of Capital. As described more fully under “Liquidity and Capital Resources” below, our sources of capital going forward will primarily be cash flow from operating activities, funding under our credit facility, cash on hand and proceeds from the sale of properties and if an appropriate opportunity presents itself, sales 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 June 30, 2010, we had $5.7 million of availability under our credit facility.

Exploration and Development Activity. We believe that our high quality asset base, high degree of operational control and inventory of drilling projects position us for future growth. At December 31, 2009, we operated properties accounting for approximately 76% 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 84 were classified as proved undeveloped at December 31, 2009) on our existing leaseholds the successful development of which we believe could significantly increase our production and proved reserves.

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 44% of our estimated proved reserves at December 31, 2009 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. Additionally, due to the increased number of drilling rigs running in the Williston Basin 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.

Operational Update

Rocky Mountain:

- In McKenzie County, North Dakota, subsequent to June 30, 2010, Abraxas spudded its first of three operated horizontal wells in the Bakken/Three Forks oil play. The first well will target the Three Forks formation. The second well will target the middle Bakken formation. It is anticipated that all three wells will be drilled sequentially and that each well will have horizontal laterals of approximately 9,000 feet and that each well will be completed with 20 or more stages of fracture stimulation. It is anticipated that each well will take approximately 30-45 days to drill but a shortage of frac crews could delay completion. Abraxas owns an approximate 64% working interest in the first well and an approximate 70% working interest in the second well.

- In Divide County, North Dakota, Abraxas participated in a Three Forks horizontal well for its 1.9% working interest. The well was drilled to a total measured depth of 18,500 feet, including an 8,500 foot lateral, and completed with a 24-stage fracture stimulation. The well has been on-line for over 30 days and is currently producing approximately 400 barrels of oil and associated gas per day.

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- In Williams County, North Dakota, Abraxas participated in a Bakken horizontal well for its 2.1% working interest. The well was drilled to a total measured depth of 19,700 feet, including a 9,700 foot lateral, and completed with a 28-stage fracture stimulation. The well has been on-line for over 60 days and is currently producing approximately 300 barrels of oil and associated gas per day.

Permian Basin:

- In Nolan County, Texas, Abraxas anticipates spudding its first of two operated wells late in the third quarter of 2010. The first well will be a vertical well and will target the Strawn, Caddo and Ellenburger formations and the second well will be a horizontal well and will target the Strawn formation. Abraxas owns a 100% working interest in each of these wells.

Canada:

- In the Twining area of Alberta, Canadian Abraxas ("Canaxas") is currently drilling its first of two operated horizontal wells targeting the Pekisko formation at an approximate depth of 5,400 feet. The first well has reached total depth and waiting on completion. The second well has been spudded. Each successful well will earn Canaxas approximately five sections, or 3,200 net acres. Canaxas owns a 100% working interest in each of these wells.

Non-Core Divestitures. We have initiated a divestiture program, principally aimed at non-operated, non-core assets, to generate cash for debt repayment and to accelerate our drilling program. During the fourth quarter of 2009 and the first six months of 2010, we sold certain non-core assets for total net proceeds of approximately $13.4 million ($2.4 million in 2009 and $11.0 million in 2010). In total, these properties produced approximately 202 Boepd, and had approximately 728 MBoe of proved reserves, which equates to $66,446 per producing Boepd and $18.48 per proved Boe in sales proceeds. The first $10 million of net proceeds was used to repay the term loan portion of our credit facility. We have identified an additional $20 to $25 million of similar non-core assets that we will attempt to divest on similar terms over the next several months. We anticipate that approximately 50% of any future net proceeds from such sales will be allocated to further debt reduction and 50% to accelerate our capital program.

Borrowings and Interest. At June 30, 2010, we had a total of $139.3 million outstanding under our credit facility and availability of $5.7 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 numerous 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 arrangement for $100 million at a fixed rate of 3.367% originally expired on August 12, 2010. This 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.

Results of Operations

The following table sets forth certain of our operating data for the periods presented.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2010	2009	2010	2009
	(in thousands)			
Operating Revenue: (1)				
Oil Sales	$ 9,068	$ 7,639	$ 17,930	$ 12,669
Gas Sales	5,578	4,480	12,579	10,046

Rig Operations		259		247		520		500
Other		4		2		6		3
	$	14,909	$	12,368	$	31,035	$	23,218
Operating Income (loss)	$	1,527	$	64	$	4,785	$	(1,759)
Oil Production (MBbl)		129		147		252		290
Gas Production (MMcf)		1,444		1,584		2,882		3,205
Average Oil Sales Price ($/Bbl) (1)	$	70.20	$	52.05	$	71.15	$	43.69
Average Gas Sales Price ($/Mcf) (1)	$	3.86	$	2.83	$	4.36	$	3.13

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

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Comparison of Three Months Ended June 30, 2010 to Three Months Ended June 30, 2009

Operating Revenue. During the three months ended June 30, 2010, operating revenue from oil and gas sales increased to $14.6 million compared to $12.1 million in the three months ended June 30, 2009. The increase in revenue was due to higher realized prices, which was offset by a decrease in production volumes. Increased commodity prices contributed $4.3 million to revenue from oil and gas sales while decreased production volumes had a negative impact of approximately $1.8 million for the quarter ended June 30, 2010.

Oil sales volumes decreased from 147 MBbls during the quarter ended June 30, 2009 to 129 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 the first six months of 2010, natural field declines and the timing of new wells being brought on line. The divested properties produced 9.5 MBbls during the second quarter of 2009, compared to 2.7 MBbls during the same period of 2010. New wells brought onto production during the first six months of 2010 contributed 5.9 MBbls to production for the three months ended June 30, 2010. Gas sales volumes decreased from 1,584 MMcf for the three months ended June 30, 2009 to 1,444 MMcf for the same period of 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 first six months of 2010, natural field declines and the timing of new wells being brought on line. The divested properties produced 40.2 MMcf during the second quarter of 2009 compared to 23.5 MMcf for the same period of 2010. New wells brought onto production during the first six months of 2010 contributed 86.9 MMcf to production for the three months ended June 30, 2010.

Average sales prices, before the impact of derivative activities, for the quarter ended June 30, 2010 were:

- $ 70.20 per Bbl of oil, and
- $ 3.86 per Mcf of gas

Average sales prices, before the impact of derivative activities, for the quarter ended June 30, 2009 were:

- $ 52.05 per Bbl of oil, and
- $ 2.83 per Mcf of gas

Lease Operating Expenses ("LOE"). LOE for the three months ended June 30, 2010 increased to $6.6 million from $6.0 million for the same period in 2009. The increase in LOE was due to higher production taxes in the quarter ended June 30, 2010 as compared to the same period of 2009 as a result of higher commodity prices, as well as higher cost of services. LOE on a per BOE basis for the three months ended June 30, 2010 was $17.75 per BOE compared to $14.57 for the same period of 2009. The increase in per BOE was due to higher cost as well as lower sales volumes for the three months ended June 30, 2010 as compared to the same period of 2009.

General and Administrative Expenses ("G&A"). G&A expenses, excluding stock-based compensation increased to $1.7 million for the quarter ended June 30, 2010 from $1.3 million for the same period of 2009. The increase in G&A was primarily related to the opening of our Canadian office in September 2009. Our G&A on a per BOE basis was $4.47 for the quarter ended June 30, 2010 compared to $3.10 for the same period of 2009. The increase in G&A expense on a per BOE basis was primarily due to increased cost and lower production volumes in the second quarter of 2010 compared to the same period in 2009.

Equity-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 the Company's common stock have been granted. For the quarters ended June 30, 2010 and 2009, equity based compensation was approximately $537,000 and $329,000 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, as well as options granted to directors during the quarter ended June 30, 2010 which vest and are expensed upon grant.

Depreciation, Depletion and Amortization Expenses ("DD&A"). Depreciation, depletion and amortization expense decreased to $4.4 million for the three months ended June 30, 2010 from $4.5 million for same period of 2009. The decrease in DD&A was primarily the result of decreased production volumes for the second quarter of 2010 as compared to the same period of 2009 offset by an increase to the depletion base as determined by the December 31, 2009 reserve report. Our DD&A per BOE for the three months ended June 30, 2010 was $11.98 per BOE compared to $10.98 per BOE in 2009. The increase in DD&A per BOE was due to the higher depletion base for the period offset by lower production volumes.

Interest Expense. Interest expense decreased to $2.3 million for the quarter ended June 30, 2010 from $3.1 million for the same period of 2009. The decrease in interest expense for the quarter ended June 30, 2010 was primarily due to lower levels of debt as compared to the same period of 2009, as well as lower interest rates.

Gain (loss) from derivative contracts. 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. 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. The estimated unearned value of our derivative contracts is a net asset of approximately $2.2 million as of June 30, 2010. For the quarter ended June 30, 2010, we had an unrealized gain on our commodity derivative contracts of $6.6 million and an unrealized loss of $611,000 on our interest rate swap. We realized a gain on the commodity swaps of $1.2 million for the quarter ended June 30, 2010 and a realized loss on the interest rate swap of $569,000. The loss on the interest rate swap was the result of floating interest rates being lower than our fixed contract rates. The unrealized gain of $6.6 million on the commodity swaps was primarily due to the contract prices of our gas derivative contracts being higher than the market prices at the end of the quarter.

Non-controlling interest. Non-controlling interest represents the share of the net income (loss) of Abraxas Energy Partners for the period owned by the partners other than Abraxas Petroleum. For the quarter ended June 30, 2009, the non-controlling interest in the net income of the Partnership was approximately $10.1 million. The Partnership was merged into Abraxas Petroleum Corporation on October 5, 2009; accordingly, there was no non-controlling interest adjustment for the quarter ended June 30, 2010.

Comparison of Six Months Ended June 30, 2010 to Six Months Ended June 30, 2009

Operating Revenue. During the six months ended June 30, 2010, operating revenue from oil and gas sales increased to $30.5 million compared to $22.7 million for the same period of 2009. The increase in revenue was due to higher realized prices offset by a decrease in production volumes. Increased commodity prices contributed $11.9 million to revenue from oil and gas sales while decreased production volumes had a negative impact of approximately $4.1 million for the six months ended June 30, 2010

Oil sales volumes decreased from 290 MBbls during the six months ended June 30, 2009 to 252 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 the first six months of 2010, natural field declines and the timing of new wells being brought on line. New wells brought onto production during the first six months of 2010 contributed 7.6 MBbls to production for the six months ended June 30, 2010. The divested properties produced 24.7 MBbls during the first six months of 2009 compared to 8.5 MBbls for the same period of 2010. Gas sales decreased to 2,882 MMcf for the six months ended June 30, 2010 from 3,205 MMcf for the same period of 2009. The decrease in gas sales was due to sales of non-core properties during the latter part of the fourth quarter of 2009 and first six months of 2010, natural field declines and the timing of new wells being brought on line. New wells brought onto production during the first six months of 2010 contributed 125.4 MMcf to production for the six months ended June 30, 2010. The divested properties produced 95.3 MMcf during the first six months of 2009 compared to 75.7 for the same period of 2010.

Average sales prices, before the impact of derivative activities, for the six months ended June 30, 2010 were:

- $71.15 per Bbl of oil, and
- $4.36 per Mcf of gas

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Average sales prices, before the impact of derivative activities, for the six months ended June 30, 2009 were:

- $ 43.69 per Bbl of oil, and
- $ 3.13 per Mcf of gas

Lease Operating Expenses ("LOE"). LOE for the six months ended June 30, 2010 increased to $12.9 million from $11.9 million for the same period in 2009. The increase in LOE was due to higher production taxes in the six months ended June 30, 2010 as compared to the same period of 2009 as a result of higher commodity prices, as well as higher cost of services. LOE on a per BOE basis for the six months ended June 30, 2010 was $17.55 per BOE compared to $14.38 for the same period of 2009. The increase in LOE per BOE was due to higher cost as well as lower sales volumes for the six months ended June 30, 2010 as compared to the same period of 2009.

General and Administrative Expenses ("G&A"). G&A expenses, excluding stock-based compensation expense, increased from $3.1 million for the first six months of 2009 to $3.5 million for the same period of 2010. The increase in G&A was primarily related to the opening of our Canadian office in September 2009. G&A expense on a per BOE basis was $4.76 for the six months ended June 30, 2010 compared to $3.80 for the same period of 2009. The increase in G&A expense on a per BOE basis was due to increased cost and lower sales volumes in the first six months of 2010 compared to the same period in 2009.

Equity-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 the Company's common stock have been granted. For the six months ended June 30, 2010 and 2009, equity based compensation was approximately $847,000 and $596,000 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, as well as options granted to Directors during the quarter ended June 30, 2010 which vest and are expensed upon grant.

Depreciation, Depletion and Amortization Expenses ("DD&A"). DD&A expense decreased to $8.7 million for the six months ended June 30, 2010 from $9.0 million for same period of 2009. The decrease in DD&A was primarily the result of decreased sales volumes for the second quarter of 2010 as compared to the same period of 2009 offset by an increase to the depletion base as determined by the December 31, 2009 reserve report. Our DD&A on a per BOE basis for the six months ended June 30, 2010 was $11.84 per BOE compared to $10.91 per BOE in 2009. The increase in DD&A per BOE was due to the higher depletion base for the period offset by lower sales volumes.

Interest Expense. Interest expense decreased to $4.6 million for the six months ended June 30, 2010 from $5.6 million for the same period of 2009. The decrease in interest expense for the six months ended June 30, 2010 was due to lower levels of debt as compared to the same period of 2009, as well as lower interest rates.

Gain (loss) from derivative contracts. 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. 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. The estimated unearned value of our derivative contracts is a net asset of approximately $2.2 million as of June 30, 2010. For the six months ended June 30, 2010, we had an unrealized gain on our commodity derivative contracts of $19.0 million and an unrealized loss of $1.4 million on our interest rate swap. We realized a gain on the commodity swaps of $1.0 million for the six months ended June 30, 2010 and a realized loss on the interest rate swap of $1.1 million. The loss on the interest rate swap was the result of floating interest rates being lower than our fixed contract rates. The unrealized gain of $19.0 million on the commodity swaps was primarily due to the contract prices of our gas derivative contracts being higher than the market prices at the end of the period.

Non-controlling interest Non-controlling interest represents the share of the net income (loss) of Abraxas Energy Partners for the period owned by the partners other than Abraxas Petroleum. For the six months ended June 30, 2009, the non-controlling interest in the net income of the Partnership was approximately $6.6 million. The Partnership was merged into Abraxas Petroleum Corporation on October 5, 2009; accordingly, there was no non-controlling interest adjustment for the quarter ended June 30, 2010.

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Recently Issued Accounting Pronouncements

We discuss recently adopted and issued accounting standards in Item 1. Condensed Consolidated Financial Statements—Note 1, "Basis of Presentation."

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 costs:

- 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 continue to grow the business through the development of existing properties and the acquisition of new properties.

Our principal sources of capital going forward will be 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 June 30, 2010 our current liabilities of approximately $16.3 million exceeded our current assets of $15.8 million resulting in a working capital deficit of $500,000. This compares to a working capital deficit of approximately $17.4 million at December 31, 2009. Current liabilities at June 30, 2010 primarily consisted of the current portion of derivative liabilities of $4.8 million, trade payables of $6.2 million, revenues due third parties of $3.3 million, and other accrued liabilities of $1.5 million.

Capital expenditures. Capital expenditures during the first six months of 2010 were $8.6 million compared to $7.5 million during the same period of 2009. The table below sets forth the components of these capital expenditures on a historical basis for the six months ended June 30, 2010 and 2009.

	Six Months Ended June 30,	
	2010	2009
	(in thousands)	
Expenditure category:		
Development	$8,423	$7,380
Facilities and other	169	130
Total	$8,592	$7,510

During the six months ended June 30, 2010 and 2009, capital expenditures were primarily for development of our existing properties. We anticipate making capital expenditures for 2010 of $30.0 million. These anticipated expenditures are subject to adequate cash flow from operations and availability under our credit facility. If these sources of funding do not prove to be sufficient, we may also issue additional shares of equity securities or sell debt securities, although we may not be able to complete any financings on terms acceptable to us, if at all. Our ability to make all of our budgeted capital expenditures will also be subject to availability of drilling rigs and other field equipment and services. With the increased number of drilling rigs running in the Williston Basin 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. 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 market conditions and other related economic factors. There has been a significant decline in commodity prices since the second quarter of 2008; while oil prices improved during the second six months of 2009 and first six months of 2010, gas prices have remained fairly weak. Should the prices of oil and gas decline or 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 expenditures budget. If we decrease our capital expenditures budget, we may not be able to offset oil and gas production decreases caused by natural field declines and sales of producing properties.

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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:

	Six Months Ended June 30, 2010	Six Months Ended June 30, 2009
	(in thousands)	
Net cash provided by operating activities	$5,748	$9,546
Net cash provided by (used in) investing activities	2,416	(7,510)
Net cash used in financing activities	(7,431)	(2,080)
Total	$733	$(134)

Operating activities during the six months ended June 30, 2010 provided us $5.7 million of cash compared to providing $9.5 million in the same period in 2009. Net income plus non-cash expense items during 2010 and 2009 and net changes in operating assets and liabilities accounted for most of these funds. Investing activities provided $2.4 million during the six months ended June 30, 2010 compared to using $7.5 million for the six months ended June 30, 2009. Funds provided for the first six months of 2010 were proceeds from the sale of non-core properties offset by expenditures for the development of our existing properties. For the first six months of 2009, capital expenditures were primarily for the development of existing properties. Financing activities used $7.4 million for the first six months of 2010 compared to using $2.1 million for the same period of 2009.

Future Capital Resources. 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 financing on terms acceptable to us, if at all.

We have initiated a divestiture program, principally aimed at non-operated, non-core assets, to generate cash for debt repayment and to accelerate our drilling program. During the fourth quarter of 2009 and the first six months of 2010, we sold certain non-core assets for total net proceeds of approximately $13.4 million ($2.4 million in 2009 and $11.0 million in 2010). In total, these properties produced approximately 202 Boepd, and had approximately 728 MBoe of proved reserves, which equates to $66,446 per producing Boepd and $18.48 per proved Boe in sales proceeds. The first $10 million of net proceeds was used to repay the term loan portion of our credit facility. We have identified an additional $20 to $25 million of similar non-core assets that we will attempt to divest on similar terms over the next several months. We anticipate that approximately 50% of any future net proceeds from such sales will be allocated to further debt reduction and 50% to accelerate our capital program.

Cash from operating activities is dependent upon commodity prices and production volumes. Oil and gas prices are volatile and declined significantly during the first part of 2009. Oil prices strengthened during the second six months of 2009 and the first six months of 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.

Our cash flow from operations will also depend upon the volume of oil and gas that we produce. Unless we otherwise expand and develop reserves, our production volumes may decline as reserves are produced. In the future we may continue to sell non-core 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 in the Williston Basin 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

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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 44% of our total estimated proved reserves at December 31, 2009 were classified as undeveloped.

We could also seek capital through the sale of debt and equity securities. The current state of the equity and debt markets will have a significant impact on our ability to sell debt or equity securities on terms as favorable as those which existed prior to the current economic crisis.

Contractual Obligations

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

- Long-term debt
- Interest on long-term debt
- 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 June 30, 2010:

		Payments due in twelve month periods ending:			
Contractual Obligations (in thousands)	Total	June 30, 2011	June 30, 2012-2013	June 30, 2014-2015	Thereafter
Long-Term Debt (1)	$144,463	$147	$139,625	$4,691	$—
Interest on long-term debt (2)	19,720	8,339	10,797	584	—
Lease obligations (3)	168	50	92	26	—
Total	$164,351	$8,536	$150,514	$5,301	$—

(1) These amounts represent the balances outstanding under our credit facility and the real estate lien note. These repayments 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 30, 2014.

We maintain a reserve for cost associated with the retirement of tangible long-lived assets. At June 30, 2010, our reserve for these obligations totaled $9.6 million for which no contractual commitment exists.

Off-Balance Sheet Arrangements. At June 30, 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 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 June 30, 2010, we were not engaged in any legal proceedings that were expected, individually or in the aggregate, to have a material adverse effect on the Company.

Other obligations. We make and will continue to make substantial capital expenditures for the acquisition, development, exploration 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 and borrowings under our bank credit facilities and other sources. Given our high degree of operating control, the timing and incurrence of operating and capital expenditures is largely within our discretion.

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Long-Term Indebtedness

Long-term debt consisted of the following:

	June 30, 2010	December 31, 2009
Credit facility – Term portion	$—	$8,000
Credit facility – Revolving portion	139,300	138,500
Real estate lien note	5,163	5,233
	144,463	151,733
Less current maturities	(146)	(8,141)
	$144,317	$143,592

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. In connection with the Merger, we borrowed $145.0 million under the credit facility, of which $135.0 million was borrowed under the revolving portion and $10.0 million was borrowed under the term loan portion. As of June 30, 2010, $139.3 million was outstanding under the revolving portion of the credit facility. The term portion of the credit facility was paid in full on March 30, 2010.

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 $145.0 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 $145.0 million was determined based upon our reserve report dated December 31, 2009. 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 June 30, 2010, the interest rate on the revolving portion of the credit facility was 5.75%.

We also borrowed $10.0 million under the term loan portion of the credit facility at the closing of the Merger. Outstanding amounts under the term loan 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) 4.75%, or, if we elect, at the greater of (1) 2.0% and (2) LIBOR plus, in each case, 5.75%. The term portion of the credit facility was paid in full on March 30, 2010.

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

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day of each quarter of not more than 4.50 to 1.00 for the quarter ending September 30, 2009 through the quarter ending September 30, 2010, and not more than 4.00 to 1.00 thereafter. 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 (which relates to derivative instruments and hedging activities and was previously referred to as SFAS 133) and ASC 410-20 (which relates to asset retirement obligations and was previously referred to as SFAS 143) 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 (which relates to stock-based compensation and was previously referred to as SFAS 123R), 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 June 30, 2010. As of June 30, 2010, the current ratio was 1.52 to 1.00, the interest coverage ratio was 4.88 to 1.00 and the total debt to EBITDAX ratio was 2.34 to 1.00.

The credit facility also required that we enter into hedging arrangements for specified volumes, which equated to approximately 85% of the estimated oil and gas production from our net proved developed producing reserves through December 31, 2012 and 70% 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, the Company 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 its 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

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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 June 30, 2010, $5.2 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 85% of our estimated oil and gas production from our net proved developed producing reserves through December 31, 2012 and on 70% for the calendar year 2013.

The following table sets forth our derivative contract position as of June 30, 2010:

	Fixed-Price Swaps			
	Oil		Gas	
Contract Period	Daily Volume (Bbl)	Swap Price	Daily Volume (MMBtu)	Swap Price
2010	1,158	$73.28	11,258	$5.73
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 six months ended June 30, 2010, we incurred a realized gain of approximately $1.0 million and an unrealized gain of approximately $19.0 million on our commodity derivative contracts as compared to a realized gain of approximately $14.0 million and an unrealized loss of approximately $14.8 million on our commodity derivative contracts during the first six months of 2009. 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, the 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 numerous 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, 2009, we had, subject to the limitation discussed below, $121.7 million of net operating loss carryforwards for U.S. tax purposes. These loss carryforwards will expire through 2028 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 $91.5 million for deferred tax assets at December 31, 2009.

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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, 2009 or for the six months ended June 30, 2010. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of June 30, 2010, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years from 1999 through 2009 remain open to examination by the tax jurisdictions to which the Company is subject.

Item 3. 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 materially 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 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 six months ended June 30, 2010, a 10% decline in oil and gas prices would have reduced our operating revenue, cash flow and net income by approximately $3.0 million for the six months ended June 30, 2010, 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. In 2003, we elected not to designate our derivative contracts as hedges. Accordingly the derivative contracts are recorded on the balance sheet at fair value with changes in the market value of the derivatives contracts being recorded as a gain or loss on derivative contracts in the current period.

The following table sets forth our derivative contract position as of June 30, 2010:

	Fixed-Price Swaps			
	Oil		Gas	
Contract Period	Daily Volume (Bbl)	Swap Price	Daily Volume (MMBtu)	Swap Price
2010	1,158	$73.28	11,258	$5.73
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 arrangement 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, 1012.

At June 30, 2010, the aggregate fair market value of our commodity derivative contracts was an asset of approximately $5.8 million and the aggregate fair market value of our interest rate swap was a liability of approximately $3.6 million.

For the six months ended June 30, 2010, we recognized a realized gain of $1.0 million and an unrealized gain of $19.0 million on our commodity derivative contracts and we recognized a realized loss of $1.1 million and an unrealized loss of $1.4 million on our interest rate swap.

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Interest rate risk

We are subject to interest rate risk associated with borrowings under our credit facility. As of June 30, 2010, we had $139.3 million of outstanding indebtedness under our credit facility. 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 June 30, 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. 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 arrangement 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 4. Controls and Procedures.

As of the end of the period covered by this report, our Chief Executive Officer and Chief Financial Officer carried out an evaluation of the effectiveness of Abraxas' "disclosure controls and procedures" (as defined in the Securities Exchange Act of 1934 Rules 13a-15(e)and 15d-15(e)) and concluded that the disclosure controls and procedures were effective.

There were no changes in our internal controls over financial reporting during the three month period ended June 30, 2010 covered by this report that could materially affect, or are reasonably likely to materially affect, our financial reporting.

ABRAXAS PETROLEUM CORPORATION

PART II
OTHER INFORMATION

Item 1. Legal Proceedings.

There have been no changes in legal proceedings from that described in the Company's Annual Report on Form 10-K for the year ended December 31, 2009, and in Note 7 in the Notes to Condensed Consolidated Financial Statements contained in Part I of this report on Form 10-Q.

Item 1A. Risk Factors.

In addition to the other information set forth in this report, you should carefully consider the factors discussed in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2009, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing Abraxas. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

Derivatives regulation included in current financial reform legislation could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices.

The July 2010 Dodd-Frank Wall Street Reform and Consumer Protection Act provides for new statutory and regulatory requirements for derivative transactions, including oil and gas hedging transactions. Certain transactions will be required to be cleared on exchanges and cash collateral will have to be posted. The Act provides for a potential exemption from these clearing and cash collateral requirements for commercial end-users and it includes a number of defined terms that will be used in determining how this exemption applies to particular derivative transactions and the parties to those transactions. Since the Dodd-Frank Act mandates the Commodities Futures and Trading Commission to promulgate rules to define these terms, we do not know the definitions the CFTC will actually adopt or how these definitions will apply to us.

Item 2. Unregistered Sales of Equity Securities and Use of Proceeds.

None

Item 3. Defaults Upon Senior Securities.

None

Item 4. (Removed and Reserved).

Item 5. Other Information.

None

Item 6. Exhibits

(a)	Exhibits
Exhibit 31.1	Certification - Robert L.G. Watson, CEO
Exhibit 31.2	Certification – Chris E. Williford, CFO
Exhibit 32.1	Certification pursuant to 18 U.S.C. Section 1350 – Robert L.G. Watson, CEO
Exhibit 32.2	Certification pursuant to 18 U.S.C. Section 1350 – Chris E. Williford, CFO

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ABRAXAS PETROLEUM CORPORATION

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, as amended the Registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Date: August 16, 2010	By: /s/Robert L.G. Watson
	ROBERT L.G. WATSON, President and Chief Executive Officer
Date: August 16, 2010	By: /s/Chris E, Williford
	CHRIS E. WILLIFORD, Executive Vice President and Principal Accounting Officer

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