ABRAXAS PETROLEUM CORP
Form 10-Q
May 17, 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 MARCH 31, 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 May 13, 2010 was:

Class	Shares Outstanding
Common Stock, $.01 Par Value	76,246,967

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Forward-Looking Information

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 make planned capital expenditures;
- declines in our production of oil and gas;
- the prices we receive for our oil and gas;
- our ability to raise equity capital or incur additional indebtedness;
- political and economic conditions in oil producing countries, especially those in the Middle East;
- price and availability of alternative fuels;
- our restrictive debt covenants;
- our acquisition and divestiture activities;
- weather conditions and events;
- the proximity, capacity, cost and availability of pipelines and other transportation facilities;
- results of our hedging activities; and
- other factors discussed elsewhere in this document.

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 natural 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 natural 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 natural 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 recompletion. 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

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proven effective by actual tests in the area and in the same reservoir.

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

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

“PV-10” means estimated future net revenue, discounted at a rate of 10% per annum, before income taxes and with no price or cost escalation or de-escalation in accordance with guidelines promulgated by the SEC.

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

ABRAXAS PETROLEUM CORPORATION AND SUBSIDIARIES

FORM 10 – Q

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PART I
FINANCIAL INFORMATION

PART 1

FINANCIAL INFORMATION

Item 1. Financial Statements

Abraxas Petroleum Corporation

Condensed Consolidated Balance Sheets

(in thousands)

	March 31, 2010 (Unaudited)	December 31, 2009
Assets		
Current assets:		
Cash and cash equivalents	$976	$1,861
Accounts receivable, net:		
Joint owners	934	865
Oil and gas production	7,820	7,873
Other	21	31
	8,775	8,769
Derivative asset – current	5,599	325
Other current assets	386	514
Total current assets	15,736	11,469
Property and equipment:		
Oil and gas properties, full cost method of accounting:		
Proved	450,795	454,142
Unproved properties excluded from depletion	—	—
Other property and equipment	11,298	11,259
Total	462,093	465,401
Less accumulated depreciation, depletion, and amortization	(313,487)	(309,245)
Total property and equipment – net	148,606	156,156
Deferred financing fees, net	5,133	5,804
Derivative asset – long-term	7,723	2,253
Other assets	613	554
Total assets	$177,811	$176,236

See accompanying notes to condensed consolidated financial statements

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Abraxas Petroleum Corporation

Condensed Consolidated Balance Sheets (continued)

(in thousands except share and per share data)

	March 31, 2010 (Unaudited)	December 31, 2009
Liabilities and Stockholders' Deficit		
Current liabilities:		
Accounts payable	$ 7,959	$ 8,773
Oil and gas production payable	3,491	3,606
Accrued interest	478	563
Other accrued expenses	1,294	770
Derivative liability – current	7,746	7,047
Current maturities of long-term debt	137	8,141
Total current liabilities	21,105	28,900
Long-term debt, excluding current maturities	143,561	143,592
Derivative liability – long-term	9,747	11,781
Future site restoration	10,283	10,326
Total liabilities	184,696	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 76,236,967 and 76,231,751	762	762
Additional paid-in capital	182,962	182,647
Accumulated deficit	(190,791)	(201,974)
Accumulated other comprehensive income	182	202
Total stockholders' deficit	(6,885)	(18,363)
Total liabilities and stockholders' deficit	$ 177,811	$ 176,236

See accompanying notes to condensed consolidated financial statements

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Abraxas Petroleum Corporation

Condensed Consolidated Statements of Operations

(Unaudited)

(in thousands except per share data)

	Three Months Ended March 31, 2010	Three Months Ended March 31, 2009
Revenue:		
Oil and gas production revenues	$15,863	$10,596
Rig revenues	261	253
Other	2	1
	16,126	10,850
Operating costs and expenses:		
Lease operating and production taxes	6,289	5,869
Depreciation, depletion and amortization	4,241	4,487
Rig operations	197	188
General and administrative (including equity-based compensation of $310 and $267)	2,141	2,129
	12,868	12,673
Operating income (loss)	3,258	(1,823)
Other (income) expense		
Interest income	(2)	(5)
Interest expense	2,334	2,556
Financing costs	—	362
Amortization of deferred financing fees	809	212
Gain on derivative contracts (unrealized $(11,696) and $(6,430))	(10,977)	(12,865)
Other	(89)	21
	(7,925)	(9,719)
Consolidated net income	11,183	7,896
Net income attributable to non-controlling interest	—	(3,446)
Net income	$11,183	$4,450
Net earnings attributable to Abraxas Petroleum common stockholders - per common share – basic	$0.15	$0.09

Net earnings attributable to Abraxas Petroleum common stockholders - per common share – diluted	$0.15	$0.09

See accompanying notes to condensed consolidated financial statements

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Abraxas Petroleum Corporation

Condensed Consolidated Statements of Cash Flows

(Unaudited)

(in thousands)

	Three Months Ended March 31, 2010	2009
Cash flows from Operating Activities		
Net income	$11,183	$7,896
Adjustments to reconcile net income to net cash provided by operating activities:		
Change in derivative fair value	(12,079)	(6,911)
Depreciation, depletion, and amortization	4,241	4,487
Accretion of future site restoration	137	141
Amortization of deferred financing fees	809	212
Stock-based compensation	310	267
Other non-cash items	24	18
Changes in operating assets and liabilities:		
Accounts receivable	(6)	2,228
Other	63	75
Accounts payable and accrued expenses	(665)	(5,463)
Net cash provided by (used in) operations	4,017	2,950
Cash flows from Investing Activities		
Capital expenditures, including purchases and development of properties	(5,171)	(4,271)
Proceeds from the sale of oil and gas properties	8,475	—
Net cash provided by (used in) investing activities	3,304	(4,271)
Cash flows from Financing Activities		
Proceeds from long-term borrowings	—	3,000
Payments on long-term borrowings	(8,035)	(34)
Deferred financing fees	(138)	(492)
	—	(2,257)

Partnership distributions to non-controlling interest		
Other	(33)	(207)
Net cash used in financing operations	(8,206)	10
Decrease in cash	(885)	(1,311)
Cash, at beginning of period	1,861	1,924
Cash, at end of period	$976	$613
Supplemental disclosures of cash flow information:		
Interest paid	$2,195	$2,415

See accompanying notes to condensed consolidated financial statements

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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 March 31, 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. Certain prior period balances have been restated to reflect the changes required by ASC 810.

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.

ASC 815, Determining Whether an Instrument (or Embedded Feature) is indexed to an Entity's Own Stock, is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. This standard provides a new two-step model to be applied in determining whether a financial instrument or an embedded feature is indexed to an issuer's own stock and thus able to qualify for the ASC 815-10-15 scope exception. The adoption of this standard has not had a significant impact on the Company's consolidated financial position, results of operations or cash flows.

In June 2008, the FASB ratified EITF Issue No. 07-5, Determining Whether an Instrument (or Embedded Feature) is indexed to an Entity's Own Stock ("EITF 07-5"). EITF 07-5 is effective for financial statements issued for fiscal years beginning after December 15, 2008, and interim periods within those fiscal years. Early application is not permitted. EITF 07-5 provides a new two-step model to be applied in determining whether a financial instrument or an embedded feature is indexed to an issuer's own stock and thus able to qualify for the SFAS No. 133 paragraph 11(a) scope exception. The Company intends to utilize liability treatment of warrants going forward. The adoption of this standard has not had a significant impact on the Company's consolidated financial position, results of operations or cash flows.

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 months ended March 31, 2010 and 2009, the Company recognized expense of $194,000 and $181,000, respectively, related to stock options.

The following table summarizes the stock option activities for the three months ended March 31, 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	$ 1.34	$ 5,480
Granted	859	$ 2.09	$ 1.53	1,315
Exercised	—	$ —	$ —	—
Expired or canceled	(7)	$ 3.46	$ 2.05	(14)
Outstanding, March 31, 2010	4,942	$ 2.17	$ 1.37	$ 6,781

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The following table shows the weighted average assumptions used in the Black-Scholes valuation of the fair value of option grants for the three months ended March 31, 2010.

Expected dividend yield		0%
Volatility		83.87%
Risk free interest rate		2.83%
Expected life		6.25Years
Fair value of options granted (in thousands)	$	1,315
Weighted average grant date fair value per share of options granted	$	1.53

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

	March 31, 2010	December 31, 2009
Options exercisable	2,053	1,808

As of March 31, 2010, there was approximately $3.2 million of unamortized compensation expense related to outstanding options that will be recognized in 2010 through 2014.

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 quarter ended March 31, 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	—		—
Vested/Released	(118)		1.80
Forfeited	(5)		.94
Unvested March 31, 2010	426	$	2.14

For the quarters ended March 31, 2010 and 2009, the Company incurred $116,000 and $39,000, respectively, in equity based compensation expense relating to restricted stock. As of March 31, 2010, there was approximately $738,000 of unamortized compensation expense related to outstanding restricted shares that will be recognized in 2010 through 2013.

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.

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For the quarter ended March 31, 2009, the Partnership incurred $22,000 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 Board of Directors of the general partner of the Partnership awarded phantom units with distribution equivalency rights under its long-term incentive plan to certain key employees of Abraxas Petroleum.

For the quarter ended March 31, 2009, the Partnership incurred $25,000 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 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 March 31, 2010, our net capitalized costs of oil and gas properties did not exceed the present value of our estimated proved reserves.

Working Capital (Deficit).

At March 31, 2010 our current liabilities of approximately $21.1 million exceeded our current assets of $15.7 million resulting in a working capital deficit of $5.4 million. This compares to a working capital deficit of approximately $17.4 million at December 31, 2009. Current liabilities at March 31, 2010 primarily consisted of the current portion of derivative liabilities of $7.7 million, trade payables of $8.0 million, revenues due third parties of $3.5 million, and other accrued liabilities of $1.3 million.

Recently Issued Accounting Pronouncements

Stock Compensation – Effect of Denominating the Exercise Price of a Share-Based Payment Award in the Currency of the Market in Which the Underlying Equity Security Trades. In April 2010, the Financial Accounting Standards Board's ("FASB") Emerging Issues Task Force ("EITF") issued an amendment to previously issued guidance regarding the classification of a share-based payment award as either equity or a liability. The amendments clarify that a share-based payment award with an exercise price denominated in the currency of a market in which a substantial portion of the entity's equity securities trades should not be considered to contain a condition that is not a market, performance or service condition. Therefore, such an award should not be classified as a liability if it otherwise qualifies as equity. This guidance is effective for fiscal years and interim periods within those fiscal years beginning on or after December 15, 2010. Earlier application is permitted. This guidance should be applied by recording a cumulative-effect adjustment to the opening balance of retained earnings and the cumulative-effect adjustment should be calculated for all awards outstanding as of the beginning of the fiscal year in which it is initially applied, as if the guidance had been applied consistently since the inception of the award. The cumulative-effect adjustment should be presented separately. The Company is currently evaluating the impact of this guidance on its operating results, financial position and cash flows.

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 8 – Fair Value Measurements."

Variable Interest Entities. In June 2009, the FASB issued authoritative guidance related to variable interest entities which changes how a reporting entity determines when an entity that is insufficiently capitalized or is not controlled through voting rights should be consolidated and modifies the approach for determining the primary beneficiary of a variable interest entity. This guidance requires a reporting entity to provide additional disclosures about its involvement with variable interest entities and any significant changes in risk exposure due to that involvement. The guidance related to variable interest entities was effective on January 1, 2010 and did not have an impact on the Company's operating results, financial position or cash flows.

Subsequent Events. In May 2009, the FASB issued authoritative guidance on subsequent events to incorporate accounting guidance that originated as auditing standards into the body of authoritative literature issued by the FASB. This guidance required the evaluation of subsequent events through the date the financial statements are issued or are available for issue and the disclosure of the date through which subsequent events were evaluated and the basis for that date. This guidance was effective for interim and annual financial periods ending after June 15, 2009. The Company adopted the requirements of this guidance for the period ended June 30, 2009 and the adoption did not have an impact on the Company's operating results, financial position or cash flows. On February 25, 2010, the FASB amended this guidance to remove the requirement to disclose the date through which an entity has evaluated subsequent events.

Modernization of Natural Gas and Oil Reporting. In January 2009, the SEC issued revisions to the natural gas and oil reporting disclosures, "Modernization of Oil and Gas Reporting, Final Rule" (the "Final Rule"). In addition to changing the definition and disclosure requirements for natural gas and oil reserves, the Final Rule changed the requirements for determining quantities of natural gas and oil reserves. The Final Rule also changed certain accounting requirements under the full cost method of accounting for natural gas and oil activities. The amendments are designed to modernize the requirements for the determination of natural gas and oil reserves, aligning them with current practices and updating them for changes in technology. The Final Rule was effective for annual reports on Form10-K for fiscal years

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ending on or after December 31, 2009. In addition, in January 2010, the FASB issued an accounting standards update relating to standards for extractive oil and gas activities. The accounting standards update amends existing standards to align the proved reserves calculation and disclosure requirements under US GAAP with the requirements in the SEC rules. The Company adopted the new standards effective December 31, 2009. The new standards were applied prospectively as a change in estimate. In April 2010, the FASB issued a further accounting standards update regarding extractive oil and gas industries to incorporate in accounting standards the revisions to Rule 4-10 of the SEC's Regulation S-X. The amendment primarily consists of the addition and deletion of definitions of terms related to fossil fuel exploration and production arising from technology changes over the past several decades. The accounting guidance in Rule 4-10 did not change.

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 quarters ended March 31, 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 provisions ASC 740-10. ASC 740-10 did not have any effect on the Company's financial position or results of operations for the quarters ended March 31, 2010 and 2009. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of March 31, 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. Debt

Long-Term Indebtedness

Long-term debt consisted of the following:

	March 31, 2010	December 31, 2009
Credit facility – Term portion	$ —	$ 8,000
Credit facility – Revolving portion	138,500	138,500
Real estate lien note	5,198	5,233
	143,698	151,733
Less current maturities	(137)	(8,141)
	$ 143,561	$ 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 March 31, 2010, $138.5 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 March 31, 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 (other than Canadian Abraxas Petroleum Corporation) 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 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

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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.

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.

We were in compliance with all covenants as of March 31, 2010. As of March 31, 2010, the current ratio was 1.26 to 1.00, the interest coverage ratio was 4.69 to 1.00 and the total debt to EBITDAX ratio was 2.26 to 1.00.

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 March 31, 2010, $5.2 million was outstanding on the note.

Note 4. Earnings (Loss) Per Share

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

	Three Months Ended March 31,	
	2010	2009
Numerator:		
Net income available to common stockholders	$ 11,183	$ 4,450
Denominator:		
	75,805	49,499

Denominator for basic earnings per share – weighted-average shares				
Effect of dilutive securities:				
Stock options and warrants		213		343
Denominator for diluted earnings per share - adjusted weighted-average shares and assumed conversions		76,018		49,842
Net income per common share – basic	$	0.15	$	0.09
Net income per common share – diluted	$	0.15	$	0.09

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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 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.

The following table sets forth our derivative contract position at March 31, 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 March 31, 2010, the aggregate fair market value of our commodity derivative contracts was a liability of approximately $1.2 million, based on average NYMEX strip prices as of March 31, 2010 of $86.23 Per Bbl and $5.43 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% and 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. The fair value of this interest rate swap was a liability of $3.0 million at March 31, 2010.

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 Abraxas, 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 quarter ended March 31, 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.

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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 table present information about the Company's assets and liabilities measured at fair value as of March 31, 2010 and December 31, 2009, 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 March 31, 2010
Assets:				
Investment in common stock	$ 199	$ —	$ —	$ 199
NYMEX Fixed Price Derivative contracts	—	13,322	—	13,322
Total Assets	$ 199	$ 13,322	$ —	$ 13,521
Liabilities:				
NYMEX Fixed Price Derivative contracts	$ —	$ 14,497	$ —	$ 14,497
Interest Rate Swaps	—	—	2,996	2,996
Total Liabilities	$ —	$ 14,497	$ 2,996	$ 17,493

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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 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

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 March 31, 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 quarter ended March 31, 2010 is as follows:

	Derivative Assets and (Liabilities) - net
Balance December 31, 2009	$ (2,256)
Total realized and unrealized losses included in change in net liability	(1,335)
Settlements during the period	595
Balance March 31, 2010	$ (2,996)

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 March 31, 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;
- the level of total sales volumes of oil and gas;
- the availability of, and our ability to raise additional capital resources and provide liquidity to meet cash flow needs;
- the level of and interest rates on borrowings; and

- the level and success of exploration and development activity.

Commodity Prices and Hedging 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 control. Significant declines in prices for oil and gas could have a material adverse effect on our financial condition, results of operations, cash flows and quantities of reserves recoverable on an economic basis.

Recently, the prices of oil and gas have been volatile. During the first quarter of 2010, the price of oil increased significantly from the levels experienced during the first quarter of 2009. During the first quarter of 2010, the New York Mercantile (NYMEX) price for West Texas Intermediate (WTI) averaged $78.81 per barrel as compared to $43.19 per barrel during the first quarter of 2009. During the first quarter of 2010, the average price of gas increased slightly from the levels experienced during the first quarter of 2009, however gas prices have been declining since the early part of the quarter. NYMEX Henry Hub spot prices for gas averaged $5.09 per MMBtu for the first quarter of 2010 compared to $4.55 for the same period of 2009. Prices closed the quarter at $83.76 per Bbl of oil and $3.84 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 quarter of 2010, differentials averaged $6.66 per Bbl of oil and $0.22 per Mcf of gas as compared to $8.06 per Bbl of oil and $0.92 per Mcf of gas during the first quarter of 2009. In the first quarter of 2010 we experienced lower oil differential compared to the first quarter of 2009, due to an overall decline in basis differentials for oil across all of our operating areas. In the first quarter of 2010, we experienced lower gas differentials compared to the first quarter 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. 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 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.

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 quarter of 2010, we incurred a realized loss of $138,000 and an unrealized gain of $12.5 million. In 2009, we incurred a realized gain of $17.9 million and an unrealized loss of $28.4 million. We have not designated any of these derivative contracts as a hedge as prescribed by applicable accounting rules.

The following table sets forth our derivative position at March 31, 2010:

	Fixed Price Swap			
	Oil		Gas	
Contract Periods	Daily Volume	Swap Price	Daily Volume	Swap Price

	(Bbl)		(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 March 31, 2010, the aggregate fair market value of our oil and gas derivative contracts was a liability of approximately $1.2 million, based on average NYMEX strip prices as of March 31, 2010, of $86.23 per Bbl and $5.43 per MMbtu.

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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 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 $5.2 million during the first quarter 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.

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 March 31, 2010, we had $6.5 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.

Operational Update

Rocky Mountain:

- In the Bakken/Three Forks oil play in the Williston Basin, Abraxas is in the process of spacing and permitting its first two operated wells in the play. Both wells are located in eastern McKenzie County, North Dakota and will be drilled on 1,280 acre spacing units - one well will target the middle Bakken formation and the other well will target the underlying Three Forks formation. It is anticipated 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. The first well is currently scheduled to spud in July. Abraxas continues to acquire leases in western North Dakota and eastern Montana as it fills out its existing acreage blocks in anticipation of additional operated drilling in the last half of

2010.

- In Divide County, North Dakota, Abraxas participated in a successful Bakken horizontal well for its 10.3% working interest. The well was drilled to a total measured depth of 16,200 feet and completed with a 20-stage fracture stimulation. The well is currently cleaning up frac fluid and flowing meaningful amounts of oil and gas.
- In Divide County, North Dakota, Abraxas participated in a Three Forks horizontal well for its 1.9% working interest, during the first quarter of 2010. The well was drilled to a total measured depth of 18,500 feet, including an 8,500 foot lateral, and is currently waiting on an 18-stage fracture stimulation.
- In Williams County, North Dakota, Abraxas participated in a Bakken horizontal well for its 2.1% working interest, during the first quarter of 2010. The well was drilled to a total measured depth of 19,700 feet, including a 9,700 foot lateral, and has completed 9 stages of a planned 28-stage fracture stimulation.

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Mid-Continent:

- In Hemphill County, Texas, Abraxas participated for its 8.3% working interest in a successful Granite Wash horizontal well, the Huff 16-5H operated by Cimarex Energy Co., during the first quarter of 2010. The well was drilled to a total measured depth of 15,800 feet, including a 5,000 foot lateral, and completed with a 12-stage fracture stimulation. The well produced an average of 17.9 MMcfepd during the first 60 days of production and cumulatively produced over 1.0 Bcfe of liquids-rich gas during that period. The well is currently producing approximately 12.5 MMcfepd. Net to Abraxas' interest, this current production rate equates to approximately 1.0 MMcfepd, or 167 Boepd, plus natural gas liquids. Abraxas owns approximately 1,700 net acres in this play, all of which are held-by-production.

Permian Basin:

- In Nolan County, Texas, Abraxas plans to drill two oil wells during the third quarter of 2010. One vertical well will test the Strawn, Caddo and Ellenburger formations and a second horizontal well will evaluate the Strawn formation. Abraxas owns a 100% working interest in each of these wells.
- In Ward County, Texas, Abraxas plans to drill four shallow oil wells during the fourth quarter of 2010. Each of these vertical wells will test the Yates formation at an approximate depth of 2,800 feet. Abraxas owns a 100% working interest in each of these wells.

Gulf Coast:

- In the Eagle Ford shale play of South Texas, Abraxas has leased approximately 7,500 net acres (3,000 of which is held-by-production) and continues to acquire acreage in geologically specific areas in anticipation of drilling its first Eagle Ford horizontal well later this year. Abraxas owns between 75% and 100% working interest in this play.
- In Bee County, Texas, Abraxas drilled the Bradford #1 to a total depth of 10,300 feet, during the first quarter of 2010. Several deeper Wilcox zones have been tested with marginal results and shallower zones will be tested in the near future. Abraxas owns a 40% working interest in this well.
- In San Patricio County, Texas, Abraxas drilled two oil development wells during the first quarter of 2010. The Welder #86 and #87 were each drilled to the base of the Frio formation at a depth of approximately 8,700 feet. Both wells have been completed and are currently producing approximately 95 barrels of oil equivalent per day. Abraxas owns a 100% working interest in each of these wells.

Canada:

Since 1996, Abraxas has been an active operator in Canada, principally in the Alberta Basin, and has recently formed a wholly-owned subsidiary, Canadian Abraxas Petroleum Corporation ("Canaxas"), with a core group of employees which were very successful in growing two former Abraxas subsidiaries. During the first quarter of 2010, Canaxas entered into a farmout agreement with a major Canadian independent to earn acreage by drilling two horizontal oil wells to the Pekisko formation at an approximate depth of 5,400 feet. Each successful well will earn Canaxas approximately five sections, or 3,200 net acres, in the Twining area of Alberta. Canaxas will own a 100% working interest in each of these wells and expects to spud the first well in the third quarter of 2010.

Non-Core Divestitures. We have initiated a divestiture program, principally aimed at non-operated, non-core assets, to generate cash for debt repayment and to accelerate our drilling program. During the fourth quarter of 2009 and the first quarter of 2010, we sold certain non-core assets for total net proceeds of approximately $11.0 million ($2.4 million in 2009 and $8.6 million in 2010). In total, these properties produced approximately 142 Boepd, and had approximately 606 MBoe of proved reserves , which equates to $77,465 per producing Boepd and $18.15 per proved Boe. The first $10 million of net proceeds was used to repay the term loan portion of our credit facility. Approximately 50% of any future net proceed from such sales will be allocated to further debt reduction and 50% to accelerate our capital program. We have identified an additional $20 to $30 million of similar non-core assets that we will attempt to divest on similar terms over the next several months.

Borrowings and Interest. At March 31, 2010, we had a total of $138.5 million outstanding under our credit facility and availability of $6.5 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

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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 March 31, 2010	2009
	(in thousands)	
Operating revenue: (1)		
Oil sales	$8,863	$5,030
Gas sales	7,000	5,566
Rig operations	261	253
Other	2	1
	$16,126	$10,850
Operating income (loss)	$3,258	$(1,823)
Oil production (MBbl)	122.8	143.2
Gas production (MMcf)	1,438	1,621
Average oil sales price ($/Bbl) (1)	$72.15	$35.13
Average gas sales price ($/Mcf) (1)	$4.87	$3.43

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

Comparison of Three Months Ended March 31, 2010 to Three Months Ended March 31, 2009

Operating Revenue. During the three months ended March 31, 2010, operating revenue from oil and gas sales increased to $15.9 million from $10.6 million for the first quarter of 2009. The increase in revenue was primarily due to higher commodity prices during the first quarter of 2010. Higher prices contributed $7.6 million to oil and gas revenue while decreased production volumes had a negative impact of $2.4 million to oil and gas revenue for the quarter ended March 31, 2010.

Average sales prices before the impact of derivative activities for the quarter ended March 31, 2010 were:

§ $72.15 per Bbl of oil,

§ $ 4.87 per Mcf of gas

Average sales prices before the impact of derivative activities for the quarter ended March 31, 2009 were:

§ $35.13 per Bbl of oil,

§ $ 3.43 per Mcf of gas

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Oil sales volumes decreased from 143.2 MBbls during the quarter ended March 31, 2009 to 122.8 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, natural field declines and the timing of new wells being brought on line. The divested properties produced 5.9 MBbls during the first quarter of 2009. Gas production volumes decreased from 1,621 MMcf for the three months ended March 31, 2009 to 1,438 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, natural field declines and the timing of new wells being brought on line. The divested properties produced 3.2 MMcf during the first quarter of 2009.

Lease Operating Expenses. Lease operating expenses ("LOE") for the three months ended March 31, 2010 increased to $6.3 million from $5.9 million in 2009. The increase in LOE was due to higher production taxes in the quarter ended March 31, 2010 as compared to the same period of 2009 as a result of higher commodity prices, as well as higher cost of services. LOE per BOE for the three months ended March 31, 2010 was $17.35 per BOE compared to $14.20 for the same period of 2009.

General and Administrative ("G&A") Expenses. G&A expenses, excluding equity-based compensation, decreased to $1.8 million for the quarter ended March 31, 2010 from $1.9 million during for the quarter ended March 31, 2009. The decrease in G&A was primarily due to a decrease in consulting and professional fees in 2010 as compared to 2009. G&A expense per BOE was $5.05 for the first quarter of 2010 compared to $4.50 for the same period of 2009. The increase in G&A expense per BOE was primarily due to decreased production volumes in the first 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 March 31, 2010 and 2009, equity based compensation was approximately $310,000 and $267,000 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.

Depreciation, Depletion and Amortization Expenses. Depreciation, depletion and amortization ("DD&A") expense decreased to $4.2 million for the three months ended March 31, 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 first 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 March 31, 2010 was $11.70 per BOE compared to $10.85 per BOE in 2008. 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 first three months of 2010 from $2.6 million for the same period of 2009. The decrease in interest expense for the first quarter of 2010 was primarily due to lower levels of debt as compared to the same period of 2009.

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 liability of approximately $4.2 million as of March 31, 2010. For the quarter ended March 31, 2010, we had an unrealized gain on our commodity derivative contracts of $12.5 million. We realized a loss on the commodity swaps of $138,000 for the quarter ended March 31, 2010 and a realized loss on the interest rate swap of $580,000. 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 $12.5 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.

Ceiling Limitation Write-down. We record the carrying value of our oil and gas properties using the full cost method of accounting for oil and gas properties. Under this method, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under the full cost accounting rules, the net capitalized cost of oil and gas properties less related deferred taxes, are limited by country, to the lower of

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the unamortized cost or the cost ceiling, defined as the sum of the present value of estimated unescalated future net revenues from proved reserves, discounted at 10%, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. If the net capitalized cost of oil and gas properties exceeds the ceiling limit, we are subject to a ceiling limitation write-down to the extent of such excess. A ceiling limitation write-down is a charge to earnings which does not impact cash flow from operating activities. However, such write-downs do impact the amount of our stockholders' equity. The cost ceiling represents the present value (discounted at 10%) of net cash flows from sales of future production, using commodity prices on the last day of the quarter, or alternatively, if prices subsequent to that date have increased, a price near the periodic filing date of the our financial statements. As of March 31, 2009, our net capitalized costs of oil and gas properties exceeded the present value of our estimated proved reserves by $37.1 million. These amounts were calculated considering March 31, 2009 quarter end prices as prescribed by SEC rules in place at the time. We did not adjust the capitalized costs of our properties because subsequent to March 31, 2009, crude oil and natural gas prices increased such that capitalized costs did not exceed the present value of the estimated proved oil and gas reserves on a consolidated basis as determined using increased NYMEX prices on May 7, 2009 of $58.32 per Bbl for oil and $4.00 per Mcf for gas. As of March 31, 2010, the net capitalized costs of our oil and gas properties did not exceed the present value of our estimated proved reserves

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

Non-controlling interest. Non-controlling interest represents the share of the net income (loss) of Abraxas Energy Partners for the period owned by the partners other than Abraxas Petroleum. For the quarter ended March 31, 2009, the non-controlling interest in the net income of the Partnership was approximately $3.4 million. The Partnership was merged into Abraxas Petroleum Corporation on October 5, 2009; accordingly, there was no non-controlling interest deduction for the quarter ended March 31, 2010.

Recently Issued Accounting Pronouncements

Stock Compensation – Effect of Denominating the Exercise Price of a Share-Based Payment Award in the Currency of the Market in Which the Underlying Equity Security Trades. In April 2010, the Financial Accounting Standards Board (“FASB”)’s Emerging Issues Task Force (“EITF”) issued an amendment to previously issued guidance regarding the classification of a share based payment award as either equity or a liability. The amendments clarify that a share-based payment award with an exercise price denominated in the currency of a market in which a substantial portion of the entity’s equity securities trades should not be considered to contain a condition that is not a market, performance or service condition. Therefore, such an award should not be classified as a liability if it otherwise qualifies as equity. This guidance is effective for fiscal years and interim periods within those fiscal years beginning on or after December 15, 2010. Earlier application is permitted. This guidance should be applied by recording a cumulative-effect adjustment to the opening balance of retained earnings and the cumulative-effect adjustment should be calculated for all awards outstanding as of the beginning of the fiscal year in which it is initially applied, as if the guidance had been applied consistently since the inception of the award. The cumulative-effect adjustment should be presented separately. The Company is currently evaluating the impact of this guidance on its operating results, financial position and cash flows.

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.

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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 Measurements."

Variable Interest Entities. In June 2009, the FASB issued authoritative guidance related to variable interest entities which changes how a reporting entity determines when an entity that is insufficiently capitalized or is not controlled through voting rights should be consolidated and modifies the approach for determining the primary beneficiary of a variable interest entity. This guidance requires a reporting entity to provide additional disclosures about its involvement with variable interest entities and any significant changes in risk exposure due to that involvement. The guidance related to variable interest entities was effective on January 1, 2010 and did not have an impact on the Company's operating results, financial position or cash flows.

Subsequent Events. In May 2009, the FASB issued authoritative guidance on subsequent events to incorporate accounting guidance that originated as auditing standards into the body of authoritative literature issued by the FASB. This guidance required the evaluation of subsequent events through the date the financial statements are issued or are available for issue and the disclosure of the date through which subsequent events were evaluated and the basis for that date. This guidance was effective for interim and annual financial periods ending after June 15, 2009. The Company adopted the requirements of this guidance for the period ended June 30, 2009 and the adoption did not have an impact on the Company's operating results, financial position or cash flows. On February 25, 2010, the FASB amended this guidance to remove the requirement to disclose the date through which an entity has evaluated subsequent events.

Modernization of Natural Gas and Oil Reporting. In January 2009, the SEC issued revisions to the natural gas and oil reporting disclosures, "Modernization of Oil and Gas Reporting, Final Rule" (the "Final Rule"). In addition to changing the definition and disclosure requirements for natural gas and oil reserves, the Final Rule changed the requirements for determining quantities of natural gas and oil reserves. The Final Rule also changed certain accounting requirements under the full cost method of accounting for natural gas and oil activities. The amendments are designed to modernize the requirements for the determination of natural gas and oil reserves, aligning them with current practices and updating them for changes in technology. The Final Rule was effective for annual reports on Form10-K for fiscal years ending on or after December 31, 2009. In addition, in January 2010, the FASB issued an accounting standards update relating to standards for extractive oil and gas activities. The accounting standards update amends existing standards to align the proved reserves calculation and disclosure requirements under US GAAP with the requirements in the SEC rules. The Company adopted the new standards effective December 31, 2009. The new standards were applied prospectively as a change in estimate. In April 2010, the FASB issued a further accounting standards update regarding extractive oil and gas industries to incorporate in accounting standards the revisions to Rule 4-10 of the SEC's Regulation S-X. The amendment primarily consists of the addition and deletion of definitions of terms related to fossil fuel exploration and production arising from technology changes over the past several decades. The accounting guidance in Rule 4-10 did not change.

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;

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- 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 March 31, 2010 our current liabilities of approximately $21.1 million exceeded our current assets of $15.7 million resulting in a working capital deficit of $5.4 million. This compares to a working capital deficit of approximately $17.4 million at December 31, 2009. Current liabilities at March 31, 2010 primarily consisted of the current portion of derivative liabilities of $7.7 million, trade payables of $8.0 million, revenues due third parties of $3.5 million, and other accrued liabilities of $1.3 million.

Capital expenditures. Capital expenditures during the first three months of 2010 were $5.2 million compared to $4.3 million during the same period of 2009. The table below sets forth the components of these capital expenditures on a historical basis for the three months ended March 31, 2010 and 2009.

	Three Months Ended March 31,	
	2010	2009
	(in thousands)	
Expenditure category:		
Development	$5,133	$4,238
Facilities and other	38	33
Total	$5,171	$4,271

During the three months ended March 31, 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. 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 half of 2009 and first quarter of 2010, gas prices remain 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.

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

	Three Months Ended March 31,	
	2010	2009
	(in thousands)	
Net cash provided by operating activities	$4,017	$2,950
Net cash (used in) provided by investing activities	3,304	(4,271)
Net cash (used in) provided by financing activities	(8,206)	10
Total	$(885)	$(1,311)

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Operating activities during the three months ended March 31, 2010 provided us $4.0 million of cash compared to providing $2.9 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. Financing activities used $8.2 million for the first three months of 2010 compared to providing $10,000 for the same period of 2009. Funds used in 2010 were primarily payments on debt. Funds provided in 2009 were borrowings under our credit facility of $3.0 million less distributions by the Partnership to non-controlling interest of approximately $2.3 million. Investing activities provided $3.3 million during the three months ended March 31, 2010 compared to using $4.3 million for the quarter ended March 31, 2009. Property sales of $8.5 million during the first quarter of 2010 were offset by $5.2 million in capital expenditures for the development of our existing properties during the quarter. For the first quarter of 2009, capital expenditures were primarily for the development of existing properties.

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 quarter of 2010, we sold certain non-core assets for total net proceeds of approximately $11.0 million ($2.4 million in 2009 and $8.6 million in 2010). In total, these properties produced approximately 142 Boepd, and had approximately 606 MBoe of proved reserves, which equates to $77,465 per producing Boepd and $18.15 per proved Boe. The first $10 million of net proceeds was used to repay the term loan portion of our credit facility. Approximately 50% of any future net proceeds from such sales will be allocated to further debt reduction and 50% to accelerate our capital program. We have identified an additional $20 to $30 million of non-core assets that we will attempt to divest on similar terms over the next several months.

Cash from operating activities is dependent upon commodity prices and production volumes. Oil and gas prices are volatile and declined significantly during the second half of 2008 and continued to decline during the first part of 2009. Oil prices strengthened during the second half of 2009 and the first quarter 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 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 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. 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:

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- 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 March 31, 2010:

Contractual Obligations (in thousands)	Total	Payments due in twelve month periods ending: March 31, 2011	March 31, 2012-2013	March 31, 2014-2015	Thereafter
Long-Term Debt (1)	$143,698	$137	$138,819	$363	$4,379
Interest on long-term debt (2)	21,726	8,307	12,759	590	70
Lease obligations (3)	28	28	—	—	—
Total	$165,452	$8,472	$151,578	$953	$4,449

(1) These amounts represent the balances outstanding under our credit facility and our 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 August 31, 2010.

We maintain a reserve for cost associated with the retirement of tangible long-lived assets. At March 31, 2010, our reserve for these obligations totaled $10.3 million for which no contractual commitment exists.

Off-Balance Sheet Arrangements. At March 31, 2010, we had no existing off-balance sheet arrangements, as defined under SEC regulations, that have or are reasonably likely to have a current or future 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 March 31, 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 credit facilities and other sources. Given our high degree of operating control, the timing and incurrence of operating and capital expenditures is largely within our discretion.

Long-Term Indebtedness

Long-term debt consisted of the following:

	March 31, 2010	December 31, 2009
Credit facility – Term portion	$ —	$ 8,000
Credit facility – Revolving portion	138,500	138,500
Real estate lien note	5,198	5,233
	143,698	151,733
Less current maturities	(137)	(8,141)
	$ 143,561	$ 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 March 31, 2010, $138.5 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 under the revolving portion of the credit facility is subject to a borrowing base. The borrowing base of the credit facility 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 March 31, 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 (other than Canadian Abraxas Petroleum Corporation) 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

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and hedging activities and was previously referred to as SFAS 133) and ASC 410-20 (which relates to asset retirement obligations 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.

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.

We were in compliance with all covenants as of March 31, 2010. As of March 31, 2010, the current ratio was 1.26 to 1.00, the interest coverage ratio was 4.69 to 1.00 and the total debt to EBITDAX ratio was 2.26 to 1.00.

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 March 31, 2010, $5.2 million was outstanding on the note.

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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 December March 31, 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 quarter March 31, 2010, we incurred a realized loss of approximately $138,000 and an unrealized gain of approximately $12.5 million on our commodity derivative contracts as compared to a realized gain of approximately $7.0 million and an unrealized gain of approximately $6.3 million on our commodity derivative contracts during the first quarter 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.

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 as of January 1, 2007, for the year ended December 31, 2009 or for the quarter ended March 31, 2010. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of December 31, 2009, 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.

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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 quarter ended March 31, 2010, a 10% decline in oil and gas prices would have reduced our operating revenue, cash flow and net income by approximately $1.6 million for the quarter; 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 Contract 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 in current derivative gain (loss).

The following table sets forth our derivative contract position as of March 31, 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 March 31, 2010, the aggregate fair market value of our commodity derivative contracts was a liability of approximately $1.2 million and the aggregate fair market value of our interest rate swap was a liability of approximately $3.0 million.

For the quarter ended March 31, 2010, we recognized a realized loss of $138,000 and an unrealized gain of $12.5 million on our commodity derivative contracts and we recognized a realized loss of $580,000 and an unrealized loss of $756,000 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 March 31, 2010, we had $138.5 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 March 31, 2010, the interest rate on the revolving portion of the credit facility was 5.75%. For every percentage point that the LIBOR rate rises, our interest expense would increase by approximately $1.4 million on an annual basis. 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 4T. 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 March 31, 2010 covered by this report that could materially affect, or are reasonably likely to materially affect, our financial reporting.

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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.

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

None

Item 3. Defaults Upon Senior Securities.

None

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

None

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: May 17, 2010	By: /s/Robert L.G. Watson ROBERT L.G. WATSON, President and Chief Executive Officer
Date: May 17, 2010	By: /s/Chris E, Williford CHRIS E. WILLIFORD, Executive Vice President and Principal Accounting Officer

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