ABRAXAS PETROLEUM CORP
Form 10-Q
November 09, 2012

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 SEPTEMBER 30, 2012

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 (State of Incorporation)	74-2584033 (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 x 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	x
Non-accelerated filer (Do not mark if a smaller reporting company)	o	Smaller reporting company	o

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 November 5, 2012 was 92,557,088 shares.

Forward-Looking Information

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

- our success in development, exploitation and exploration activities;
- our ability to procure services and equipment for our drilling and completion activities;
- the availability of capital;
- the prices we receive for our production and the effectiveness of our hedging activities;
- our ability to make planned capital expenditures;
- declines in our production of oil and gas;
- our restrictive debt covenants;
- political and economic conditions in oil producing countries, especially those in the Middle East;
- price and availability of alternative fuels;
- our acquisition and divestiture activities;
- weather conditions and events;
- the proximity, capacity, cost and availability of pipelines and other transportation facilities; and
- other factors discussed elsewhere in this report.

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 natural gas liquids.

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.

“MBbl” – thousand barrels.

“MBoe” – thousand barrels of oil equivalent.

“Mcf” – thousand cubic feet of gas.

“Mcfe” – thousand cubic feet of gas equivalent.

“MMBbl” – million barrels.

“MMBoe” – million barrels of oil equivalent.

“MMBtu” – million British Thermal Units of gas.

“MMcf” – million cubic feet of gas.

“MMcfe” – million cubic feet of gas equivalent.

“NGL” – natural gas liquids measured in barrels.

Terms used to describe our interests in wells and acreage:

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

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

“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 in another reservoir, or to extend a known reservoir.

“Gross acres” are the number of acres in which we own a working interest.

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

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

“Net well” is the sum of fractional ownership working interests in gross wells.

“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” are those quantities of oil and gas reserves, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be commercially recoverable - from a given date forward, from known reservoirs, and under defined economic conditions, operating methods, and government regulations.

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

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

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

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

“PV-10” means estimated future net revenue, discounted at a rate of 10% per annum, before income taxes and with no price or cost escalation or de-escalation, calculated in accordance with guidelines promulgated by the Securities and Exchange Commission (“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 or de-escalation, calculated in accordance with Accounting Standards Codifications (“ASC”) 932, “Disclosures About Oil and Gas Producing Activities.”

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ABRAXAS PETROLEUM CORPORATION

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PART I
FINANCIAL INFORMATION

Item 1. Financial Statements

Abraxas Petroleum Corporation
Condensed Consolidated Balance Sheets
(in thousands)

	September 30, 2012 (Unaudited)	December 31, 2011
Assets		
Current assets:		
Cash and cash equivalents	$2,615	$—
Accounts receivable, net		
Joint owners	3,119	3,354
Oil and gas production	9,888	8,897
Other	1,603	655
	14,610	12,906
Derivative asset – current	18	11,416
Assets held for sale.	22,377	—
Other current assets	543	391
Total current assets	40,163	24,713
Property and equipment:		
Oil and gas properties, full cost method of accounting:		
Proved	541,722	490,908
Unproved properties excluded from depletion	2,025	1,100
Other property and equipment	37,551	33,783
Total	581,298	525,791
Less accumulated depreciation, depletion, and amortization	(376,673)	(346,239)
Total property and equipment – net	204,625	179,552
Investment in joint venture	—	26,215
Deferred financing fees, net	3,523	3,490
Derivative asset – long-term	1,061	6,412
Other assets	756	768
Total assets	$250,128	$241,150

See accompanying notes to condensed consolidated financial statements (unaudited)

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

	September 30, 2012 (Unaudited)	December 31, 2011
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$25,111	$21,373
Oil and gas production payable	3,897	5,835
Accrued interest	188	209
Other accrued expenses	1,822	284
Derivative liability – current	4,728	11,640
Current maturities of long-term debt	189	181
Total current liabilities	35,935	39,522
Long-term debt, excluding current maturities	145,616	126,258
Derivative liability – long-term	1,423	4,307
Other liabilities	366	—
Future site restoration	8,883	8,412
Total liabilities	192,223	178,499
Stockholders' Equity		
Preferred stock, par value $0.01 per share, authorized 1,000,000 shares; -0- issued and outstanding	—	—
Common stock, par value $0.01 per share, authorized 200,000,000 shares; 92,389,131 and 92,261,057 issued and outstanding	924	923
Additional paid-in capital	250,162	248,480
Accumulated deficit	(193,391)	(186,465)
Accumulated other comprehensive income (loss)	210	(287)
Total stockholders' equity	57,905	62,651
Total liabilities and stockholders' equity	$250,128	$241,150

See accompanying notes to condensed consolidated financial statements (unaudited)

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

	Three Months Ended September 30, 2012	Three Months Ended September 30, 2011	Nine Months Ended September 30, 2012	Nine Months Ended September 30, 2011
Revenue:				
Oil and gas production revenues	$17,146	$17,665	$49,459	$48,165
Other	24	1	42	5
	17,170	17,666	49,501	48,170
Operating costs and expenses:				
Lease operating expenses	6,816	5,670	18,132	15,251
Production taxes	1,714	1,549	4,699	4,229
Depreciation, depletion, and amortization	5,971	4,161	16,189	11,371
Impairment	11,761	—	13,067	—
General and administrative (including stock-based compensation of $413, $430, $1,612 and $1,499)	2,267	2,061	6,572	7,153
	28,529	13,441	58,659	38,004
Operating (loss) income	(11,359)	4,225	(9,158)	10,166
Other (income) expense:				
Interest income	(1)	(2)	(3)	(6)
Interest expense	1,596	983	4,061	3,924
Amortization of deferred financing fee	311	245	607	1,515
Loss (gain) on derivative contracts (unrealized $5,267, $(16,450), $(4,153) and $(13,431))	5,351	(16,641)	(4,935)	(12,394)
Equity in income of joint venture	(282)	(546)	(2,316)	(2,064)
Other	—	101	42	188
	6,975	(15,860)	(2,544)	(8,837)
Net income (loss) before income tax	(18,334)	20,085	(6,614)	19,003
Income tax expense	310	—	310	—
Net income (loss)	$(18,644)	$20,085	$(6,924)	$19,003
Net income (loss) per common share – basic	$(0.20)	$0.22	$(0.08)	$0.21
Net income (loss) per common share – diluted	$(0.20)	$0.21	$(0.08)	$0.21

See accompanying notes to condensed consolidated financial statements (unaudited)

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Abraxas Petroleum Corporation
Condensed Consolidated Statements of
Other Comprehensive Income (Loss)
(Unaudited)
(in thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Consolidated net income (loss)	$(18,644)	$20,085	$(6,924)	$19,003
Change in unrealized value of investments	8	(42)	(29)	(46)
Foreign currency translation adjustment	742	(635)	526	(513)
Other comprehensive income (loss)	750	(677)	497	(559)
Comprehensive income (loss)	$(17,894)	$19,408	$(6,427)	$18,444

See accompanying notes to condensed consolidated financial statements (unaudited)

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

	Nine Months Ended September 30,	
	2012	2011
Operating Activities		
Net income (loss)	$(6,924)	$19,003
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Equity in (income) loss of joint venture	(2,316)	(2,064)
Change in derivative fair value	(5,411)	(14,021)
Monetization of derivative contracts	12,364	—
Depreciation, depletion, and amortization	16,189	11,371
Impairment	13,067	—
Amortization of deferred financing fees	607	1,515
Accretion of future site restoration	353	335
Stock-based compensation	1,612	1,499
Changes in operating assets and liabilities:		
Accounts receivable	(1,673)	3,709
Other	(171)	(150)
Accounts payable and accrued expenses	3,633	1,838
Net cash provided by operating activities	31,330	23,035
Investing Activities		
Capital expenditures, including purchases and development of properties	(53,499)	(53,155)
Proceeds from dissolution of equity method investment	6,025	—
Proceeds from sale of oil and gas properties	—	8,457
Net cash used in investing activities	(47,474)	(44,698)
Financing Activities		
Proceeds from long-term borrowings	25,500	24,069
Payments on long-term borrowings	(6,134)	(63,113)
Deferred financing fees	(640)	(1,741)
Proceeds from issuance of common stock, net of offering costs	—	62,428
Other	33	(65)
Net cash provided by financing activities	18,759	21,578
Effect of exchange rate changes on cash	—	—
Increase (decrease) increase in cash	2,615	(85)
Cash and equivalents, at beginning of period	—	99
Cash and equivalents, at end of period	$2,615	$14

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

	Nine Months Ended September 30	
	2012	2011
Non-cash investing activities:		
Non-cash transfer of investment in joint venture	$28,531	$—
Non-cash transfer to assets held for sale	$(22,377)	—
Supplemental disclosure of cash flow information:		
Interest paid	$3,878	$ 3,663

See accompanying notes to condensed consolidated financial statements (unaudited)

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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 for the year ended December 31, 2011 filed with the SEC on March 15, 2012. 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 SEC. The results of operations and the cash flows for the periods ended September 30, 2012 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, 2011.

Consolidation Principles

The terms “Abraxas,” “Abraxas Petroleum,” “we,” “us,” “our” or the “Company” refer to Abraxas Petroleum Corporation an of its subsidiaries, including Raven Drilling, LLC (“Raven Drilling”) and a wholly-owned foreign subsidiary, Canadian Abraxas Petroleum, ULC (“Canadian Abraxas”).

Canadian Abraxas’ assets and liabilities are translated to U.S. dollars at period-end exchange rates. Income and expense items are translated at average rates of exchange prevailing during the period. Translation adjustments are accumulated as a separate component of stockholders’ equity.

Rig Accounting

In accordance with SEC Regulation S-X, no income is to be recognized in connection with contractual drilling services performed in connection with properties in which the Company or its affiliates holds an ownership, or other economic interest. Any income not recognized as a result of this limitation is to be credited to the full cost pool and recognized through lower amortization as reserves are produced.

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.

Stock-based Compensation and Option Plans

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 and directors.

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The following table summarizes the Company’s stock-based compensation expense related to stock options for the periods presented:

Three Months Ended September 30,		Nine Months Ended September 30,	
2012	2011	2012	2011
$ 300	$ 303	$ 1,245	$ 1,169

The following table summarizes the Company’s stock option activity for the nine months ended September 30, 2012:

	Number of Shares	Weighted Average Option Exercise Price Per Share	Weighted Average Grant Date Fair Value Per Share	Aggregate Fair Value
Outstanding, December 31, 2011	4,756	$2.61	$1.85	$8,214
Granted	608	$3.01	$2.17	1,322
Exercised	(79)	$0.91	$0.47	(37)
Cancelled/Forfeited	(166)	$2.30	$1.67	(277)
Outstanding, September 30, 2012	5,119	$2.69	$1.80	$9,222

The following table shows the weighted average assumptions used in the Black-Scholes calculation of the fair value of stock option grants for the nine months ended September 30, 2012:

Expected dividend yield	0	%
Volatility	81.35	%
Risk free interest rate	1.19	%
Expected life	6.7	Years
Fair value of options granted (in thousands)	$1,322	
Weighted average grant date fair value per share of options granted	$2.17	

Additional information related to stock options at September 30, 2012 and December 31, 2011 is as follows:

	September 30, 2012	December 31, 2011
Options exercisable	3,118	2,515

As of September 30, 2012, there was approximately $2.9 million of unamortized compensation expense related to outstanding stock options that will be recognized from 2012 through 2017.

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 fair value of such stock was determined using the closing price on the grant date and compensation expense is recorded over the applicable vesting periods.

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The following table summarizes the Company's restricted stock activity for the nine months ended September 30, 2012:

	Number of Shares	Weighted Average Grant Date Fair Value Per Share
Unvested, December 31, 2011	630	$3.03
Granted	57	2.13
Vested/Released	(227)	2.58
Forfeited	(9)	2.42
Unvested, September 30, 2012	451	$3.16

The following table summarizes the Company's stock-based compensation expense related to restricted stock for the periods presented:

Three Months Ended September 30,		Nine Months Ended September 30,	
2012	2011	2012	2011
$ 113	$ 127	$ 367	$ 330

As of September 30, 2012, there was approximately $1.1 million of unamortized compensation expense relating to outstanding restricted shares that will be recognized in 2012 through 2017.

Assets Held for Sale

During the quarter ended September 30, 2012 we received an offer on our Nordheim assets, previously held in our Blue Eagle Energy, LLC joint venture ("Blue Eagle") , and we began negotiations with the buyer, which are ongoing. In addition, we received an offer on various undeveloped leasehold interest in August 2012. The Nordheim assets and leaseholds are presented separately as "Assets held for sale" in the condensed consolidated balance sheet at September 30, 2012. Assets held for sale were recorded at the amount of the anticipated sales proceeds with a corresponding reduction to the full cost pool as the sale is not expected to be significant under full cost accounting rules.

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 by country, to the lower of the unamortized capitalized cost or the cost ceiling. The ceiling cost is calculated as PV-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. We calculate the projected income tax effect using the "short-cut" method for the cost ceiling test calculation. Costs in excess of the cost ceiling are charged to proved property impairment expense. No gain or loss is recognized upon sale or disposition of oil and gas properties, except where the sale or disposition causes a significant change in the relationship between capitalized cost and the estimated quantity of proved reserves. We apply the full cost ceiling test on a quarterly basis on the date of the latest balance sheet presented. At September 30, 2012, our net capitalized costs of oil and gas properties in the United States did not exceed the cost ceiling of our estimated proved reserves, however, the net capitalized cost of oil and gas properties in Canada exceeded the cost ceiling. We recorded write downs during the third and second quarters of 2012 of $11.8 million and $1.3 million respectively, for a total of $13.1 million for the nine months ended September 30, 2012.

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Restoration, Removal and Environmental Liabilities

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

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

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

The following table summarizes the Company’s asset retirement obligation transactions for the nine months ended September 30, 2012 and the year ended December 31, 2011:

	September 30, 2012	December 31, 2011
Beginning asset retirement obligation	$ 8,412	$7,734
Settled	(232)	(83)
Revisions	127	(9)
New wells placed on production and other	223	318
Accretion expense	353	452
Ending asset retirement obligation	$ 8,883	$8,412

Working Capital (Deficit)

At September 30, 2012, our current assets of approximately $40.2 million exceeded our current liabilities of $35.9 million resulting in working capital of $4.3 million. This compares to a working capital deficit of $14.8 million at December 31, 2011. Current assets at September 30, 2012 primarily consist of cash of $2.6 million, accounts receivable of $14.6 million and assets held for sale of $22.4 million. Current liabilities at September 30, 2012 primarily consisted of the current portion of derivative liabilities of $4.7 million, trade payables of $25.1 million and revenues due third parties of $3.9 million.

Note 2. Subsequent Event

Amended Credit Facility

On October 31, 2012, we entered into an amendment to our 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. As of September 30, 2012, $134.0 million was outstanding under the credit facility.

The credit facility has a maximum commitment of $300.0 million and availability is subject to a borrowing base. The borrowing base as a result of the October 31, 2012 amendment to the credit facility was $150.0 million as of October 31, 2012, consisting of $140.0 million conforming and $10.0 million nonconforming. This amount will remain in effect until the next redetermination of the borrowing base. The borrowing base 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 securing the facility 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 borrowing base will be automatically reduced 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 as of September 30, 2012 was $140.0 million. Our borrowing base was increased to $150.0 million as a result of the October 31, 2012 amendment of the credit facility was determined based upon our reserve report dated June 30, 2012 and does not include the properties held for sale. Our borrowing base can never exceed the $300.0 million maximum commitment amount. Outstanding amounts under the credit facility bear interest at (a) the greater of (1) the reference rate announced from time to time by Société Générale, (2) the Federal Funds Rate plus 0.5%, and (3) a rate determined by Société Générale as the daily one-month LIBOR plus, in each case, (b) 1.25—2.25%, depending on the utilization of the borrowing base, or, if we elect LIBOR plus 2.25%—3.25%, depending on the utilization of the borrowing base. At September 30, 2012, the interest rate on the credit facility was 4.21% based on 1-month LIBOR borrowings and level of utilization.

Subject to earlier termination rights and events of default, the stated maturity date of the credit facility is June 30, 2015. Interest is payable quarterly on reference rate advances and not less than quarterly on LIBOR advances. We are permitted to terminate the credit facility and are able, from time to time, to permanently reduce the lenders' aggregate commitment under the credit facility in compliance with certain notice and dollar increment requirements.

Each of our subsidiaries has guaranteed our obligations under the credit facility on a senior secured basis. Obligations under the credit facility are secured by a first priority perfected security interest, subject to certain permitted encumbrances, in all of our and our subsidiary guarantors' material property and assets, other than Raven Drilling.

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 of not less than 2.50 to 1.00. We are also required as of the last day of each quarter to maintain a total debt to EBITDAX ratio as of the last day of each quarter of not more than 4.00 to 1.00 and liquidity (defined as the sum of our borrowing base availability, liquid investments and unrestricted cash) of $7.5 million for each fiscal quarter ending on or after June 30, 2012 and on or before March 31, 2013. 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 a counter-party to a hedging arrangement and any assets representing a valuation account arising from the application of ASC 815 and ASC 410-20 and current liabilities exclude the current portion of long-term debt and any liabilities representing a valuation account arising from the application of ASC 815 and ASC 410-20. The interest coverage ratio is defined as the ratio of consolidated EBITDAX to consolidated interest expense for the four fiscal quarters ended on the calculation date. For the purposes of this calculation, EBITDAX is consolidated net income plus interest expense, oil and gas exploration expenses, income, franchise or margin taxes, depreciation, amortization, depletion and other non-cash charges including non-cash charges resulting from the application of ASC 718, ASC 815 and ASC 410-20 plus all realized net cash proceeds arising from the settlement or monetization of any hedge contracts 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. 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.

As of September 30, 2012, the interest coverage ratio was 7.96 to 1.00, the total debt to EBITDAX ratio was 3.31 to 1.00, our current ratio was 1.49 to 1.00 and we had liquidity of $8.6 million.

The credit facility contains a number of covenants that, among other things, restrict our ability to:

- incur or guarantee additional indebtedness;

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- 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.

The following table sets forth our derivative contract position as of September 30, 2012

	Oil	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)
2012 (October – December)	1,509	$79.22
2013	1,327	$86.70
2014 (January – August)	1,173	$95.60
2014 (September – December)	333	$82.72

At September 30, 2012, the aggregate fair market value of our commodity derivative contracts was a liability of approximately $5.1 million.

In connection with this amendment to our credit facility, we entered into additional hedges as follows:

	Oil	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)
2014	200	$86.00
2015	933	$85.00
2016	883	$84.00

Note 3. Joint Venture

On August 18, 2010, Abraxas Petroleum and its wholly-owned subsidiary, Abraxas Operating, LLC, contributed 8,333 net acres in the Eagle Ford Shale play to Blue Eagle Energy, LLC ("Blue Eagle") and received a $25.0 million equity interest in Blue Eagle pursuant to the terms of the Subscription and Contribution Agreement among Abraxas Petroleum, Abraxas Operating, Blue Eagle and Rock Oil Company, LLC ("Rock Oil") formerly known as Blue Stone Oil & Gas, LLC. Simultaneously, Rock Oil contributed $25.0 million in cash to Blue Eagle for a $25.0 million equity interest. Rock Oil committed to contribute an additional $50.0 million to Blue Eagle and upon full funding, Abraxas Petroleum would have owned a 25% equity interest and Rock Oil would have owned a 75% equity interest in Blue Eagle.

On September 4, 2012, Abraxas Petroleum Corporation entered into an Agreement to dissolve Blue Eagle with Rock Oil. The effective date of the dissolution was August 31, 2012.

Under the terms of the Agreement, Abraxas retained a 100 percent interest to the base of the Buda formation in Jourdanton, Atascosa County (4,401 net acres), a 100 percent interest in Yoakum, DeWitt County (1,868 net acres), a 25 percent interest in WyCross, McMullen County (695 net acres), and a 25 percent interest in Nordheim, DeWitt County (944 net acres). We also received $7.0 million in cash, adjusted for various working capital components, and will receive 25% of the cash and working capital in Blue Eagle upon its final liquidation.

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Through August 31, 2012 we accounted for the joint venture under the equity method of accounting in accordance with ASC 323. Under this method, Abraxas' share of net income (loss) from the joint venture is reflected as an increase (decrease) in its investment account in "Investment in joint venture" and was also recorded as equity investment income (loss) in "Equity in (income) loss of joint venture." For the three and nine months ended September 30, 2012 and 2011 we reported income of $282,000, $2.3 million, $546,000 and $2.1 million, respectively, related to Blue Eagle.

The following is condensed financial data from Blue Eagle's August 31, 2012 (date of dissolution) and December 31, 2011 financial statements:

Balance Sheets:	As of August 31, 2012	As of December 31, 2011
Assets:		
Current assets	$7,921	$11,910
Oil and gas properties	75,741	66,663
Other assets	30	36
Total assets	$83,692	$78,609
Liabilities and Members' Capital:		
Current liabilities	$1,474	$3,070
Other liabilities	48	41
Members' capital	82,170	75,498
Total liabilities and members' capital	$83,692	$78,609

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012 (1)	2011	2012 (1)	2011
Revenue	$2,319	$3,024	$12,087	$9,880
Operating expenses	1,868	1,695	6,895	4,843
Other (income) expense	(1)	(2)	(2)	(10)
Net income	$452	$1,331	$5,194	$5,047

(1) Through August 31, 2012

Note 4. 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 tax rates and laws expected to be in effect when the differences are expected to reverse.

The Company accounts for uncertain tax positions under provisions ASC 740-10. This ASC did not have any effect on the Company's financial position or results of operations for the nine months ended September 30, 2011. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of September 30, 2012, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years 2001 through 2011 remain open to examination by the tax jurisdictions to which the Company is subject. The Company and Abraxas Energy Partners, L.P., which was merged into a wholly owned subsidiary of Abraxas, have undergone audits of their 2009 Federal income tax returns. The audit of the Federal income tax return of Abraxas Energy Partners, L.P. was completed with no changes. The audit of Abraxas Petroleum Corporation resulted in a notice of a proposed adjustment of $619,000. The Company does not agree with the findings and intends to aggressively appeal the proposed adjustment; however, no assurances can be made that such appeals will be

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successful. For the three and nine months ended September 30, 2012, the Company recognized $310,000 in income tax expense related to the recent audit of its 2009 Federal tax return. This amount was determined by an analysis of what we are more likely than not have to pay. There were no deferred income tax expense or benefit due to losses and/or loss carryforwards and valuation allowances which have been recorded against such benefits.

At December 31, 2011, we had, subject to the limitation discussed below, $150.2 million of net operating loss carryforwards for U.S. tax purposes and $8.7 million of net operating loss carryforwards for Canadian tax purposes. The U.S. loss carryforward will expire in varying amounts through 2031 and the Canadian loss carryforward will expire in 2031, if not utilized.

Note 5. Long-Term Debt

The following table summarizes the Company's long-term debt:

	September 30, 2012	December 31, 2011
Credit facility	$134,000	$115,000
Rig loan agreement	7,000	6,500
Real estate lien note	4,805	4,939
	145,805	126,439
Less current maturities	(189)	(181)
	$145,616	$126,258

Credit Facility

On June 29, 2012, we entered into an amendment to our 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. As of September 30, 2012, $134.0 million was outstanding under the credit facility.

The credit agreement was further amended on October 31, 2012. The October 31, 2012 amendment removed the limitation on capital expenditures as described in our Form 10-Q as of June 30, 2012 and increased our borrowing base to $150.0 million from $140.0 million. All other covenants remained the same. See Note 2. Subsequent Event.

Rig Loan Agreement

On September 19, 2011, Raven Drilling entered into a rig loan agreement with RBS Asset Finance, Inc. to finance the costs of purchasing and refurbishing an Oilwell 2000 hp diesel electric drilling rig (the "Collateral"). The rig loan agreement provided for interim borrowings payable to Raven Drilling until the final amount of the loan was determined.

On February 14, 2012, Raven Drilling finalized the note with respect to the rig loan agreement. The principal amount of the note is $7.0 million and bears interest at 4.26%, which equates to the four-year interest swap rate plus 3.50% on the date of closing. Interest only is due for the first 18-months of the note and thereafter, the note will amortize in full over the remaining life of the note. Interest and principal, when required, is payable monthly. Subject to earlier prepayment provisions and events of default, the stated maturity date of the note is February 14, 2017. As of September 30, 2012, $7.0 million was outstanding under the rig loan agreement.

The Company has guaranteed Raven Drilling's obligations under the rig loan agreement and associated note. Obligations under the rig loan agreement are secured by a first priority perfected security interest, subject to certain permitted encumbrances, in the Collateral.

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 5.25% and is payable in monthly installments of principal and interest of $36,652 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 September 30, 2012, $4.8 million was outstanding on the note.

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Note 6. Income (Loss) Per Share

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Numerator:				
Net income (loss)	$(18,644)	$20,085	$(6,924)	$19,003
Denominator:				
Denominator for basic income (loss) per share- Weighted-average shares	91,898	91,509	91,866	89,663
Effect of dilutive securities:				
Stock options and warrants	—	2,107	—	2,497
Denominator for diluted income (loss) per share - adjusted weighted-average shares and assumed conversions	91,898	93,616	91,866	92,160
Net income (loss) per common share – basic	$(0.20)	$0.22	$(0.08)	$0.21
Net income (loss) per common share – diluted	$(0.20)	$0.21	$(0.08)	$0.21

For the three and nine months ended September 30, 2012, none of the shares issuable in connection with stock options or warrants are included in diluted shares as inclusion of these shares would be antidilutive due to the loss incurred in the period. Had there not been a loss for the periods, dilutive shares would have been 729 and 1,031, respectively.

Note 7. 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. Our derivative contracts do not qualify for hedge accounting as prescribed by ASC 815; therefore, fluctuations in the market value of our derivative contracts are recognized in earnings during the current period.

The following table sets forth our derivative contract position as of September 30, 2012;

	Oil	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)
2012 (October – December)	1,509	$79.22
2013	1,327	$86.70
2014 (January – August)	1,173	$95.60
2014 (September – December)	333	$82.72

At September 30, 2012, the aggregate fair market value of our commodity derivative contracts was a liability of approximately $5.1 million.

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In connection with the recent amendment to our credit facility, we entered into additional hedges as follows:

	Oil	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)
2014	200	$86.00
2015	933	$85.00
2016	883	$84.00

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 interest rate swap arrangement for $100 million at a fixed rate of 3.367% originally was set to expire on August 12, 2010. The swap was amended in February 2009 lowering our fixed rate to 2.95% and further amended in November 2009 lowering our fixed rate to 2.55% and extending the term through August 12, 2012. This interest rate swap expired in August 2012.

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

Fair Value of Derivative Instruments as of September 30, 2012				
	Asset Derivatives		Liability Derivatives	
Derivatives not designated as hedging instruments	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity price derivatives	Derivatives – current	$18	Derivatives – current	$4,728
Commodity price derivatives	Derivatives - noncurrent	1,061	Derivatives - noncurrent	1,423
		$1,079		$6,151

Fair Value of Derivative Instruments as of December 31, 2011				
	Asset Derivatives		Liability Derivatives	
Derivatives not designated as hedging instruments	Balance Sheet Location	Fair Value	Balance Sheet Location	Fair Value
Commodity price derivatives	Derivatives – current	$11,416	Derivatives – current	$10,094
Interest rate derivatives	Derivatives – current	—	Derivatives – current	1,546
Commodity price derivatives	Derivatives - noncurrent	6,412	Derivatives - noncurrent	4,307
		$17,828		$15,947

Gains and losses from derivative activities are reflected as "Loss (gain) on derivative contracts" in the accompanying condensed consolidated statements of operations.

Note 8. Fair Value

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.

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The following tables set forth information about the Company's assets and liabilities measured at fair value as of September 30, 2012 and December 31, 2011, and indicates the fair value hierarchy of the valuation methodologies 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 September 30, 2012
Assets:				
Investment in common stock	$76	$—	$ —	$76
NYMEX Fixed Price Derivative contracts	—	1,079	—	1,079
Total Assets	$76	$1,079	$ —	$1,155
Liabilities:				
NYMEX Fixed Price Derivative contracts	$—	$6,151	$ —	$6,151
Total Liabilities	$—	$6,151	$ —	$6,151

	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, 2011
Assets:				
Investment in common stock	$104	$—	$ —	$104
NYMEX Fixed Price Derivative contracts	—	17,828	—	17,828
Total Assets	$104	$17,828	$ —	$17,932
Liabilities:				
NYMEX Fixed Price Derivative contracts	$—	$14,401	$ —	$14,401
Interest Rate Swaps	—	—	1,546	1,546
Total Liabilities	$—	$14,401	$ 1,546	$15,947

The Company has an investment in Insignia Energy Ltd, the surviving entity in the merger with 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 September 30, 2012 and December 31, 2011 in U.S. 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. 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.

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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 interest rate swap arrangement for $100 million at a fixed rate of 3.367% originally was set to expire on August 12, 2010. The swap was amended in February 2009 lowering our fixed rate to 2.95% and further amended in November 2009 lowering our fixed rate to 2.55% and extending the term through August 12, 2012. As there are no observable market parameters for this type of swap, these derivative contracts are classified as Level 3. This interest rate swap expired in August 2012.

Additional information for the Company's recurring fair value measurements using significant unobservable inputs (Level 3) for the three and nine months ended September 30, 2012 are as follows:

	Derivative Assets (Liabilities) - net	
	Three Months Ended September 30, 2012	Nine Months Ended September 30, 2012
Balance beginning of period	$(602)	$(1,546)
Total realized and unrealized losses included in change in net liability	(1)	1,760
Settlements during the period	603	(214)
Balance September 30, 2012	$—	$—

Note 9. Business Segments

The following table provides the Company's geographic operating segment data for the three and nine months ended September 30, 2012 and 2011:

	Three Months Ended September 30, 2012			
	U.S.	Canada	Corporate	Total
Revenues:				
Oil and gas production	$16,312	$834	$—	$17,146
Other	—	—	24	24
	16,312	834	24	17,170
Expenses (income):				
Lease operating	5,645	1,171	—	6,816
Production taxes	1,689	25	—	1,714
Depreciation, depletion and amortization	5,042	867	62	5,971
Impairment	—	11,761	—	11,761
General and administrative	413	203	1,651	2,267
Net interest	114	4	1,477	1,595
Amortization of deferred financing fees	—	—	311	311
Equity in income of joint venture	—	—	(282)	(282)
Loss on derivative contracts	—	—	5,351	5,351
	12,903	14,031	8,570	35,504
Net income (loss) before tax	$3,409	$ (13,197)	$(8,546)	$(18,334)

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	Three Months Ended September 30, 2011			
	U.S.	Canada	Corporate	Total
Revenues:				
Oil and gas production	$17,269	$396	$—	$17,665
Other	—	—	1	1
	17,269	396	1	17,666
Expenses (income):				
Lease operating	5,534	136	—	5,670
Production taxes	1,549	—	—	1,549
Depreciation, depletion and amortization	3,892	207	62	4,161
General and administrative	374	133	1,554	2,061
Net interest	113	1	867	981
Amortization of deferred financing fees	—	—	245	245
Equity in income of joint venture	—	—	(546)	(546)
Gain on derivative contracts	—	—	(16,641)	(16,641)
Other	—	—	101	101
	11,462	477	(14,358)	(2,419)
Net income (loss) before tax	$5,807	$(81)	$14,359	$20,085

	Nine Months Ended September 30, 2012			
	U.S.	Canada	Corporate	Total
Revenues:				
Oil and gas production	$47,299	$2,160	$—	$49,459
Other	—	—	42	42
	47,299	2,160	42	49,501
Expenses (income):				
Lease operating	16,395	1,737	—	18,132
Production taxes	4,674	25	—	4,699
Depreciation, depletion and amortization	14,496	1,506	187	16,189
Impairment	—	13,067	—	13,067
General and administrative	1,116	498	4,958	6,572
Net interest	341	12	3,705	4,058
Amortization of deferred financing fees	—	—	607	607
Equity in income of joint venture	—	—	(2,316)	(2,316)
Gain on derivative contracts	—	—	(4,935)	(4,935)
Other	—	—	42	42
	37,022	16,845	2,248	56,115
Net income (loss) before tax	$10,277	$(14,685)	$(2,206)	$(6,614)

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	Nine Months Ended September 30, 2011			
	U.S.	Canada	Corporate	Total
Revenues:				
Oil and gas production	$47,063	$1,102	$—	$48,165
Other	—	—	5	5
	47,063	1,102	5	48,170
Expenses (income):				
Lease operating	14,789	462	—	15,251
Production taxes	4,229	—	—	4,229
Depreciation, depletion and amortization	10,653	531	187	11,371
General and administrative	1,285	511	5,357	7,153
Net interest	333	2	3,583	3,918
Amortization of deferred financing fees	—	—	1,515	1,515
Equity in income of joint venture	—	—	(2,064)	(2,064)
Gain on derivative contracts	—	—	(12,394)	(12,394)
Other	—	—	188	188
	31,289	1,506	(3,628)	29,167
Net income (loss) before tax	$15,774	$(404)	$3,633	$19,003

The following table provides the Company’s geographic asset data as of September 30, 2012 and December 31, 2011:

Segment Assets:	September 30, 2012	December 31, 2011
United States	$203,107	$167,739
Canada	13,718	19,379
Corporate	33,303	54,032
	$250,128	$241,150

Note 10. 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 September 30, 2012, 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.

The tax years 2001 through 2011 remain open to examination by the tax jurisdictions to which the Company is subject. The Company and Abraxas Energy Partners, L.P., which was merged into a wholly owned subsidiary of Abraxas, have undergone audits of their 2009 Federal income tax returns. The audit of the Federal income tax return of Abraxas Energy Partners, L.P. was completed with no changes. The audit of Abraxas Petroleum Corporation resulted in a notice of proposed adjustment of $619,000. The Company does not agree with the findings and intends to aggressively appeal the proposed adjustment; however, no assurances can be made that such appeals will be successful.

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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 for the year ended December 31, 2011 filed with the SEC on March 15, 2012.

The results of operations set forth below do not include our interest in the operations of Blue Eagle prior to August 31, 2012.

Except as otherwise noted, all tabular amounts are in thousands except per unit values.

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, 2011.

General

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

Factors Affecting Our Financial Results

While we have attained positive net income in three of the last five years, we cannot assure you that we can achieve positive 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 production. The prices we receive are dependent upon spot market prices, differentials and the effectiveness of our derivative contracts, which we sometimes refer to as hedging arrangements. Substantially all of our sales 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 production are dependent upon numerous factors beyond our control. Significant declines in commodity prices could have a material adverse effect on our financial condition, results of operations, cash flows and quantities of reserves recoverable on an economic basis.

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During the nine months ended September 30, 2012, the New York Mercantile (NYMEX) price for West Texas Intermediate crude oil (WTI) averaged $96.16 per barrel as compared to $95.41 per barrel during the nine months ended September 30, 2011. NYMEX Henry Hub spot prices for gas averaged $2.53 per MMBtu for the nine months ended September 30, 2012 compared to $4.40 for the same period of 2011. Prices closed on September 28, 2012 at $92.19 per Bbl of oil and $3.05 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;
- quality of the hydrocarbons; and
- gathering, processing and transportation costs.

The following table sets forth our average differentials for the three months ended September 30, 2012 and 2011:

	Oil - WTI		Gas – Henry Hub	
	2012	2011	2012	2011
Average realized price (Bbl and Mcf)	$83.13	$85.99	$2.47	$3.74
Average NYMEX price (Bbl and MMbtu)	$92.26	$89.49	$2.88	$4.67
Differential	$(9.13)	$(3.50)	$(0.41)	$(0.93)

Increases in the differential between the NYMEX price and the realized price we receive have in the past and could in the future significantly reduce our revenues and cash flow from operations.

We have entered into hedging arrangements for specified volumes of the estimated production from our net proved developed producing reserves through December 31, 2016. By removing a significant portion of price volatility on our future 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 recognize realized and unrealized gains on our commodity derivative contracts. In the first nine months of 2012, we recognized a realized gain of $996,000 and an unrealized gain of $4.2 million on our commodity swaps. In the first nine months of 2011, we recognized a realized gain of $726,000 and an unrealized gain of $12.2 million on our commodity swaps. 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 as of September 30, 2012:

	Oil	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)
2012 (October – December)	1,509	$79.22
2013	1,327	$86.70
2014 (January – August)	1,173	$95.60

2014 (September – December)	333	$82.72

At September 30, 2012, the aggregate fair market value of our commodity derivative contracts was a liability of approximately $5.1 million.

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In connection with the recent amendment to our credit facility, we entered into additional hedges as follows:

	Oil	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)
2014	200	$86.00
2015	933	$85.00
2016	883	$84.00

Production Volumes

Our proved reserves will decline as oil and gas are produced, unless we find, acquire or develop additional properties containing Proved reserves or conduct successful exploration and development activities in a timely manner. Based on the reserve information set forth in our reserve estimates as of December 31, 2011 (which did not include any Blue Eagle reserves), the average annual estimated decline rate for our net proved developed producing reserves is 14% 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 will be dependent, in part, upon the amount of available funds for acquisition, exploration and development projects.

We had capital expenditures of $53.5 million during the nine months ended September 30, 2012. We have a capital expenditure budget for 2012 of approximately $70.0 million. Approximately 75% of the 2012 budget will be spent on unconventional horizontal oil wells in the Bakken/Three Forks and Niobrara/Turner plays in the Rocky Mountain region of the United States, and the Eagle Ford Shale play in south Texas and the other 25% will target conventional oil plays in the Permian Basin and in the province of Alberta, Canada. The 2012 capital expenditure budget is subject to change depending upon a number of factors, including the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the availability of sufficient capital resources, and our ability to obtain permits for drilling locations.

Availability of Capital

As described more fully under “Liquidity and Capital Resources” below, our sources of capital are cash flow from operating activities, borrowings under our credit facility, cash on hand, proceeds from the sale of properties, and if an appropriate opportunity presents itself, the sale of debt or equity securities, although we may not be able to complete any financing on terms acceptable to us, if at all. As of September 30, 2012, we had $6.0 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 large inventory of drilling projects position us for future growth. At December 31, 2011, we operated properties accounting for approximately 94% 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 on our existing leaseholds, the successful development of which we believe could significantly increase our production and Proved reserves.

Our future 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 properties and our Proved reserves will decline as our reserves are produced unless we acquire or develop additional properties containing Proved 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 may also decline. In addition, approximately 43% of our estimated Proved reserves at December 31, 2011 were undeveloped. By their nature, estimates of Proved 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.

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Rig Operations

Through our wholly owned subsidiary Raven Drilling, LLC, we own and operate a drilling rig in the Bakken area of North Dakota. In accordance with SEC Regulations, we are not permitted to recognize income from drilling services in connection with properties in which we or an affiliate holds an ownership or other economic interest. Any income not recognized as a result of this is credited to the full cost pool. For the period ended September 30, 2012, there was approximately $1.6 million in unrecognized income related to our rig operations that was credited to the full cost pool.

Operational Update

At the WyCross prospect in the Eagleford shale, the company recently set a company record seven drilling days on the first of its ten well program with the Cobra B1H. The well is currently scheduled to be completed in mid-November. Drilling has commenced on the Company's second well the Mustang 1H and pad construction is underway on the Company's third well the Corvette C 1H.

In the Williston Basin, completion operations remain ongoing on the Raven 2H, 3H and the Jore 3H. In accordance with the Abraxas' historical practice, the Company will furnish 30 day IP rates for each well when available. The Company's wholly owned rig has moved to the Lillibridge block where drilling has commenced on the four well pad.

In the Permian Basin the Spires 89 1H continues to perform as expected posting cumulative production of 7,307 boe (6,457 Bbls oil and 5.1 MMcf gas).

For the quarter ended September 30, 2012, companywide production averaged approximately 4,177 boepd inclusive of two months of Blue Eagle JV production. In the Eagle Ford shale, processing downtime at Regency's Tilden plant during the month of September shut in production from the Cobra 1H for the month. Volumes from the company's Ward county acquisition and volumes post the dissolution of the Blue Eagle JV were recognized upon the effective dates of August and September, respectively.

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Results of Operations

The following table sets forth certain operating, excluding our interest in the operations of Blue Eagle, data for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2012	2011	2012	2011
Operating revenue:				
Oil sales (1)	$13,576	$13,157	$39,866	$35,320
Gas sales (1)	2,628	4,070	6,632	11,943
NGL sales	942	438	2,961	902
Other	24	1	42	5
	$17,170	$17,666	$49,501	$48,170
Operating income (loss)	$(11,359)	$4,225	$(9,158)	$10,166
Oil sales (MBbl)	163	153	468	396
Gas sales (MMcf)	1,064	1,088	3,047	3,187
NGL sales (MBbl)	30	8	80	18
BOE sales (MBbl)	370	343	1,056	945
Average oil sales price ($/Bbl) (1)	$83.13	$85.99	$85.23	$89.19
Average gas sales price ($/Mcf) (1)	$2.47	$3.74	$2.18	$3.75
Average NGL sales price ($/Bbl)	$31.69	$50.20	$37.04	$50.24
Average BOE sales price ($/BOE) (1)	$46.28	$51.49	$46.85	$50.96

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(1) Before the impact of derivative activities.

Comparison of Three Months Ended September 30, 2012 to Three Months Ended September 30, 2011

Operating Revenue. During the three months ended September 30, 2012, operating revenue decreased to $17.2 million from $17.7 million for the same period of 2011. The decrease in revenue was primarily due to lower realized commodity prices and a decrease in gas sales volumes which were partially offset by an increase in oil and NGL sales volumes. Decreased commodity prices negatively impacted operating revenue by $2.0 million. Increased oil and NGL sales volumes contributed $1.5 million to operating revenue. Decreased gas sales volumes had a negative impact of $58,000 for the quarter ended September 30, 2012.

Oil sales volumes increased to 163 MBbl during the three months ended September 30, 2012 from 153 MBbl for the same period of 2011. The increase in oil sales was due to new wells brought on line offset by natural field declines. New wells brought on production contributed 39.7 MBbl for the three months ended September 30, 2012. Gas sales volumes decreased to 1,064 MMcf for the three months ended September 30, 2012 from 1,088 MMcf for the same period of 2011. The decrease in gas sales was due to natural field declines, offset by new wells brought on production. New wells brought on production contributed 139.6 MMcf for the three months ended September 30, 2012. NGL sales volumes increased to 30 MBbl for the three months ended September 30, 2012 from 8 MBbl for the same period of 2011. The increase in NGL sales was primarily due to increased gas production in West Texas and North Dakota that has a higher NGL content than our historical gas production.

Lease Operating Expenses ("LOE"). LOE for the three months ended September 30, 2012 increased to $6.8 million from $5.7 million for the same period in 2011. The increase in LOE was due to an overall increase in the costs of services and non-recurring costs. LOE per Boe for the three months ended September 30, 2012 was $18.40 compared to $16.53 for the same period of 2011. The increase per Boe was due to higher costs offset by higher sales volumes for the three months ended September 30, 2012 as compared to the same period of 2011.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the three months ended September 30, 2012 increased to $1.7 million from $1.5 million for the same period of 2011, primarily as the result of higher oil and NGL sales volumes.

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General and Administrative ("G&A") Expenses. G&A expenses, excluding stock-based compensation, for the three months ended September 30, 2012 increased to $1.9 million from $1.6 million for the same period of 2011. The increase in G&A was primarily due to higher professional fees relating to our Internal Revenue examination and the preparation of our 2011 income tax returns, as well as higher directors expense. G&A per Boe, excluding stock-based compensation, was $5.00 for the quarter ended September 30, 2012 compared to $4.75 for the same period of 2011. The increase per Boe was due to higher costs offset by higher production volumes in the third quarter of 2012 compared to the same period in 2011.

Stock-based Compensation. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options vesting period. In addition to options, restricted shares of the Company's common stock have been granted and are valued at the date of grant and expense is recognized over their vesting period. For the quarters ended September 30, 2012 and 2011, stock-based compensation was $413,000 and $430,000, respectively. The decrease in 2012 was due to cancellations of options in the third quarter of 2012.

Depreciation, Depletion and Amortization ("DD&A") Expenses. DD&A expense for the three months ended September 30, 2012 increased to $6.0 million from $4.2 million for the same period of 2011. The increase was primarily the result of an increase to the depletion base from an increase in future development costs as determined by the June 30, 2012 reserve report, and increased production volumes for the quarter ended September 30, 2012 as compared to the same period of 2011. DD&A per Boe for the three months ended September 30, 2012 was $16.12 compared to $12.13 in 2011.

Ceiling Limitation Write-Down. We record the carrying value of our oil and gas properties using the full cost method of accounting for oil and gas properties. Under this method, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under the full cost accounting rules, the net capitalized cost of oil and gas properties less related deferred taxes, are limited by country, to the lower of the unamortized cost or the cost ceiling, defined as the sum of the present value of estimated unescalated future net revenues from proved reserves, discounted at 10%, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. If the net capitalized cost of oil and gas properties exceeds the ceiling limit, we are subject to a ceiling limitation write-down to the extent of such excess. A ceiling limitation write-down is a charge to earnings which does not impact cash flow from operating activities. However, such write-downs do impact the amount of our stockholders' equity and reported earnings. As of September 30, 2011, our net capitalized costs of oil and gas properties in the United States and Canada did not exceed the present value of our estimated proved reserves. As of September 30, 2012, the net capitalized cost of our oil and gas properties in Canada exceeded the present value of our estimated proved reserves by $13.1 million, resulting in a write down of $11.8 million for the three months ended September 30, 2012.

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

Interest Expense. Interest expense for the three months ended September 30, 2012 increased to $1.6 million from $983,000 for the same period of 2011. The increase was primarily due to higher debt levels in 2012 as compared to the same period of 2011.

(Gain) loss on derivative contracts. We account for derivative contract gains and losses based on realized and unrealized amounts. The realized derivative gains or losses are determined by actual derivative settlements during the period. Unrealized gains and losses are based on the periodic mark to market valuation of derivative contracts in place.

Our derivative contracts do not qualify for hedge accounting as prescribed by ASC 815; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Our derivative contracts consist of commodity swaps and interest rate swaps. The estimated value of our commodity derivative contracts was a liability of approximately $5.1 million as of September 30, 2012. When our derivative contract prices are higher than prevailing market prices, we incur realized and unrealized gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur realized and unrealized losses. For the three months ended September 30, 2012, we realized a loss on our commodity derivative contracts of $1.0 million and we incurred an unrealized loss of $4.3 million on our commodity derivative contracts. For the three months ended September 30, 2011, we realized a gain on our derivative contracts of $191,000, which included a realized gain of $791,000

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on our commodity swaps and a realized loss of $600,000 on our interest rate swap and we incurred an unrealized gain of $16.5 million on our derivative contracts, which included an unrealized gain of $15.9 million on our commodity swaps and an unrealized gain of $542,000 on our interest rate swap. Our interest rate swap expired in August 2012.

Equity in (income) loss of joint venture. Through August 31, 2012 we accounted for the joint venture under the equity method of accounting as prescribed by ASC 323. Under this method, Abraxas' share of net income (loss) from the joint venture was reflected as an increase (decrease) in its investment account in "Investment in joint venture" and was also recorded as equity investment income (loss) in "Equity in loss (income) of joint venture." The joint venture was dissolved on September 4, 2012 effective August 31, 2012, with the assets being distributed to the joint venture partners. The dissolution of the joint venture was accounted for as a business combination. For the three months ended September 30, 2012, through August 31, 2012, we reported income of $282,000 related to Blue Eagle. See Note 2 of the Notes to Condensed Consolidated Financial Statements.

The following table represents our equity interest in Blue Eagle's production for the three months ended September 30, 2012 and 2011:

	Three Months Ended September 30,	
	2012 (1)	2011
Oil sales (MBbl)	7	5
Gas sales (MMcf)	26	98
NGL sales (MBbl)	2	9
Average oil sales price ($/Bbl)	$92.23	$80.15
Average gas sales price ($/Mcf)	$3.00	$4.29
Average NGL sales price ($/Bbl)	$27.28	$47.21

(1) Through August 31, 2012.

Comparison of Nine Months Ended September 30, 2012 to Nine Months Ended September 30, 2011

Operating Revenue. Operating revenue increased to $49.5 million for the nine months ended September 30, 2012 from $48.2 million for the same period of 2011. The increase in revenue was primarily due to higher oil and NGL sales volumes, offset by a decrease in gas and NGL prices. Decreased commodity prices negatively impacted operating revenue by $6.8 million. Increased oil and NGL sales volumes contributed $8.4 million to operating revenue. Decreased gas sales volumes had a negative impact of $300,000 on operating revenue.

Oil sales volumes increased to 468 MBbl during the nine months ended September 30, 2012 from 396 MBbl for the same period of 2011. The increase in oil sales was due to new wells being brought on line, partially offset by natural field declines. New wells brought onto production contributed 84.3 MBbl for the nine months ended September 30, 2012. Gas sales volumes decreased to 3,047 MMcf for the nine months ended September 30, 2012 from 3,187 MMcf for the same period of 2011. The decrease in gas sales was due to natural field declines offset by new wells brought on line. New wells brought onto production contributed 262 MMcf for the nine months ended September 30, 2012. NGL sales volumes increased to 80 MBbl for the nine months ended September 30, 2012 from 18 MBbl for the same period of 2011. The increase in NGL sales was primarily due to increased gas production in West Texas and North Dakota that has a higher NGL content than our historical gas production.

Lease Operating Expenses ("LOE"). LOE for the nine months ended September 30, 2012 increased to $18.1 million compared to $15.3 million for the same period of 2011. The increase in 2012 was due to an overall increase in the costs of services and increased production activity. LOE per Boe for the nine months ended September 30, 2012 was $17.18 compared to $16.14 for the same period of 2011. The increase per Boe was due to higher overall costs offset by higher sales volumes for the nine months ended September 30, 2012 as compared to the same period of 2011.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the nine months ended September 30, 2012 increased to $4.7 million from $4.2 million for the same period of 2011. The increase was primarily the result of higher oil and NGL sales volumes for the nine months ended September 30, 2012 as compared to the same period of 2011.

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General and Administrative ("G&A") Expenses. G&A expenses, excluding stock-based compensation, for the nine months ended September 30, 2012 decreased to $5.0 million from $5.7 million for the same period of 2011. The decrease in G&A was primarily related to bonuses paid in 2011, as there were no bonuses paid in the nine months ended September 30, 2012. G&A, excluding stock based compensation, per Boe was $4.70 for the nine months ended September 30, 2012 compared to $5.98 for the same period of 2011. The decrease per Boe was primarily due to lower costs and higher production volumes in the first nine months of 2012 compared to the same period in 2011.

Stock-based Compensation. Options granted to employees and directors are valued at the date of grant and expense is recognized over the options vesting period. In addition to options, restricted shares of the Company's common stock have been granted and are valued at the date of grant and expense is recognized over their vesting period. For the nine months ended September 30, 2012 and 2011, stock-based compensation was approximately $1.6 million and $1.5 million, respectively. The increase in 2012 was due to stock option grants in the second and third quarters of 2012.

Depreciation, Depletion and Amortization ("DD&A") Expenses. DD&A expense for the nine months ended September 30, 2012 increased to $16.2 million from $11.4 million for same period of 2011. The increase was primarily the result of increased production volumes as well as increased future development cost in our June 30, 2012 reserve report. DD&A per Boe for the nine months ended September 30, 2012 was $15.34 compared to $12.03 in 2011.

Ceiling Limitation Write-Down. We record the carrying value of our oil and gas properties using the full cost method of accounting for oil and gas properties. Under this method, we capitalize the cost to acquire, explore for and develop oil and gas properties. Under the full cost accounting rules, the net capitalized cost of oil and gas properties less related deferred taxes, are limited by country, to the lower of the unamortized cost or the cost ceiling, defined as the sum of the present value of estimated unescalated future net revenues from proved reserves, discounted at 10%, plus the cost of properties not being amortized, if any, plus the lower of cost or estimated fair value of unproved properties included in the costs being amortized, if any, less related income taxes. If the net capitalized cost of oil and gas properties exceeds the ceiling limit, we are subject to a ceiling limitation write-down to the extent of such excess. A ceiling limitation write-down is a charge to earnings which does not impact cash flow from operating activities. However, such write-downs do impact the amount of our stockholders' equity and reported earnings. As of September 30, 2011, our net capitalized costs of oil and gas properties in the United States and Canada did not exceed the present value of our estimated proved reserves. As of September 30, 2012, the net capitalized cost of our oil and gas properties in Canada exceeded the present value of our estimated proved reserves by $13.1 million, resulting in a write down for the nine months ended September 30, 2012.

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

Interest Expense. Interest expense for the nine months ended September 30, 2012 increased to $4.1 million from $3.9 million for the same period of 2011. The increase was primarily due to higher debt levels in 2012 as compared to the same period of 2011.

(Gain) loss on derivative contracts. We account for derivative contract gains and losses based on realized and unrealized amounts. The realized derivative gains or losses are determined by actual derivative settlements during the period. Unrealized gains and losses are based on the periodic mark to market valuation of derivative contracts in place. Our derivative contract transactions do not qualify for hedge accounting as prescribed by ASC 815; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Our derivative contracts consist of commodity swaps and interest rate swaps. The estimated value of our commodity derivative contracts was a liability of approximately $5.1 million as of September 30, 2012. When our derivative contract prices are higher than prevailing market prices, we incur realized and unrealized gains and conversely, when our derivative contract prices are lower than prevailing market prices, we incur realized and unrealized losses. For the nine months ended September 30, 2012, we realized a gain on our derivative contracts of $782,000, which included a realized gain of $996,000 on our commodity swaps and a realized loss of $214,000 on our interest rate swap. The interest rate swap expired in August 2012. For the nine months ended September 30, 2012 we incurred an unrealized gain

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of $4.2 million on our commodity derivative contracts. For the nine months ended September 30, 2011, we realized a loss on our derivative contracts of $1.0 million, which included a realized gain of $726,000 on our commodity swaps and a realized loss of $1.7 million on our interest rate swap and we incurred an unrealized gain of $13.4 million on our derivative contracts, which included an unrealized gain of $12.2 million on our commodity swaps and an unrealized gain of $1.2 million on our interest rate swap.

Equity in (income) loss of joint venture. Through August 31, 2012 we accounted for the joint venture under the equity method of accounting. Under this method, Abraxas' share of net income (loss) from the joint venture was reflected as an increase (decrease) in its investment account in "Investment in joint venture" and was also recorded as equity investment income (loss) in "Equity in loss (income) of joint venture." The joint venture was dissolved effective September 1, 2012, with the assets being distributed to the joint venture partners. The dissolution was accounted for as a business combination. For the nine months ended September 30, 2012, we reported income of $2.3 million related to Blue Eagle. See Note 2 of the Notes to Condensed Consolidated Financial Statements.

The following table represents our equity interest in Blue Eagle's production for the nine months ended September 30, 2012 and 2011:

	Nine Months Ended September 30,	
	2012 (1)	2011
Oil sales (MBbl)	35	20
Gas sales (MMcf)	116	331
NGL sales (MBbl)	10	33
Average oil sales price ($/Bbl)	$101.69	$87.12
Average gas sales price ($/Mcf)	$2.51	$4.24
Average NGL sales price ($/Bbl)	$35.20	$45.52

(1) Through August 31, 2012.

Liquidity and Capital Resources

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

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

The amount of capital expenditures we are able to make has a direct impact on our ability to increase cash flow from operations and, thereby, will directly affect our ability to service our debt obligations and to 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 and the rig loan agreement, 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.

Working Capital (Deficit)

At September 30, 2012, our current assets of approximately $40.2 million exceeded our current liabilities of $35.9 million resulting in working capital of $4.3 million. This compares to a working capital deficit of $14.8 million at

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December 31, 2011. Current assets at September 30, 2012 primarily consist of cash of $2.6 million, accounts receivable of $14.6 million and assets held for sale of $22.4 million. Current liabilities at September 30, 2012 primarily consisted of the current portion of derivative liabilities of $4.7 million, trade payables of $25.1 million and revenues due third parties of $3.9 million.

Capital expenditures. Capital expenditures during the nine months ended September 30, 2012 were $53.5 million compared to $53.2 million during the same period of 2011. The table below sets forth the components of these capital expenditures:

	Nine Months Ended September 30,	
	2012	2011
Expenditure category:		
Development	$49,738	$41,253
Facilities and other	3,761	11,902
Total	$53,499	$53,155

During the nine months ended September 30, 2012, expenditures were primarily for development of our existing properties, the acquisition of producing properties in West Texas and the completion of the refurbishment or our drilling rig. During the nine months ended September 30, 2011, expenditures were primarily for development of our existing properties, and expenditures related to the purchase and refurbishment of the drilling rig purchased in July 2011. Our capital budget for 2012 is $70.0 million, however, under the terms of our June 29, 2012 amended credit facility, our capital expenditures for the quarter ended September 30, 2012 for drilling/completion expenditures were limited to $10.0 million, subject to certain pull-back and carry-over provisions. Capital expenditures in the ordinary course of business were not subject to the $10.0 million limit if we maintain a borrowing base availability percentage (defined as the amount available under the credit facility divided by the amount borrowed under the credit facility) of not less than 15% at June 30, 2012 and 10% at September 30, 2012 and December 31, 2012. At June 30, 2012 our borrowing base availability percentage was 12% and, as a result we were subject to this limitation during the quarter ending September 30, 2012, excluding the $7.2 million producing property acquisition which closed on July 31, 2012. This limitation was removed with the amended credit facility that closed on October 31, 2012. The 2012 capital expenditure budget is subject to change depending upon a number of factors, including the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the availability of sufficient capital resources, and our ability to obtain permits for drilling locations. Our capital expenditures could also include expenditures for the acquisition of producing properties, if such opportunities arise. Additionally, the level of capital expenditures will vary during future periods depending on economic and industry conditions and commodity prices. Should the prices of oil and gas decline and if our costs of operations increase or if our production volumes decrease, our cash flows will decrease which may result in a reduction of the capital expenditure budget. If we decrease our capital expenditure budget, we may not be able to offset oil and gas production decreases caused by natural field declines.

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

	Nine Months Ended September 30,	
	2012	2011
Net cash provided by operating activities	$31,330	$23,035
Net cash used in investing activities	(47,474)	(44,698)
Net cash provided by financing activities	18,759	21,578
Total	$2,615	$(85)

Operating activities during the nine months ended September 30, 2012 provided $31.3 million compared to providing $23.0 million in the same period of 2011. Net income (loss) plus non-cash expense items during 2012 and 2011 and net changes in operating assets and liabilities accounted for most of these funds, in addition to the monetization of our gas hedges on March 12, 2012 which provided $12.4 million. Investing activities used $47.5 million during the nine months ended September 30, 2012 compared to using $44.7 million in the same period of 2011. For the first nine months of 2012, funds used for capital expenditures were primarily for the development of existing properties, the

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acquisition of producing properties in West Texas and the completion of the refurbishment of our drilling rig. Funds used for capital expenditures for the first nine months of 2011 were primarily for the development of our existing properties. Financing activities provided $18.8 million for the first nine months of 2012 compared to providing $21.6 million for the first nine months of 2011. Funds provided during the nine months ended September 30, 2012 were primarily proceeds from borrowings on our long term debt. Funds provided during the nine months ended September 30, 2011 were primarily the proceeds from our equity offering in February 2011 of $62.2 million offset by payments on our long term debt of $58.1 million.

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

Cash from operating activities is dependent upon commodity prices and production volumes. Oil and gas prices are volatile. Oil prices have increased significantly from their low in 2009 but gas prices have remained weak. A decrease in commodity prices from current levels could reduce our cash flows from operations. This could cause us to alter our business plans, including reducing our exploration and development plans. Unless we otherwise expand and develop reserves, our production volumes may decline as reserves are produced. In the future we may sell producing properties, which could further reduce our production volumes. To offset the loss in production volumes resulting from natural field declines and sales of producing properties, we must conduct successful exploration and development activities, acquire additional producing properties or identify and develop additional behind-pipe zones or secondary recovery reserves. We believe our numerous drilling opportunities will allow us to increase our production volumes; however, our drilling activities are subject to numerous risks, including the risk that no commercially productive oil and gas reservoirs will be found. As a result, there may be a delay in procuring services for the multi-stage frac jobs that we have planned for our operated wells, which would delay the completion of successfully drilled wells. If our proved reserves decline in the future, our production will also decline and, consequently, our cash flow from operations and the amount that we are able to borrow under our credit facility will also decline. The risk of not finding commercially productive reservoirs will be compounded by the fact that 43% of our total estimated Proved reserves at December 31, 2011 were classified as Proved undeveloped reserves.

We have in the past and may in the future sell producing and non-producing properties. We have also sold debt and equity securities in the past when the opportunity has presented itself. On February 1, 2011, we closed a public offering of 23.6 million shares of common stock (of which 8.5 million shares were sold by certain selling stockholders) at a public offering price of $4.40 per share for total net proceeds to us of approximately $62.2 million. We used the net proceeds from the offering to repay outstanding indebtedness under our credit facility, to increase our 2011 capital expenditure budget and for general corporate purposes. We did not receive any proceeds from the sale of shares by the selling stockholders.

Contractual Obligations

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

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

Below is a schedule of the future payments that we are obligated to make based on agreements in place as of September 30, 2012:

Payments due in twelve month periods ending:

Contractual Obligations	Total	September 30, 2013	September 30, 2014-2015	September 30, 2016-2017	Thereafter
Long-term debt (1)	$145,805	$189	$142,488	$3,128	$—
Interest on long-term debt (2)	13,989	5,107	8,775	107	