ABRAXAS PETROLEUM CORP
Form 10-Q
November 06, 2015

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

FORM 10-Q
(Mark One)

ý	QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE QUARTERLY PERIOD ENDED September 30, 2015
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 ý 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 ýNo ¨

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 o (Do not mark if a smaller reporting company)	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 ý

The number of shares of the issuer’s common stock outstanding as of November 5, 2015 was 106,346,001.

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," "may," "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:

- the prices we receive for our production and the effectiveness of our hedging activities;
- the availability of capital;
- our success in development, exploitation and exploration activities;
- our ability to procure services and equipment for our drilling and completion activities;
- our ability to make planned capital expenditures;
- declines in our production of oil and gas;
- 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.

Table of Contents

“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:

“Developed oil and gas reserves*” Developed oil and gas reserves are reserves of any category that can be expected to be recovered:

(i) Through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) Through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

"Possible reserves*" Possible reserves are those additional reserves that are less certain to be recovered than probable reserves

3

Table of Contents

“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 developed reserves*” Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

“Proved reserves*” Reserves that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

“Proved undeveloped reserves” or “PUDs*” Reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells, in each case where a relatively major expenditure is required.

“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 Codification (“ASC”) 932, “Disclosures About Oil and Gas Producing Activities.”

“Undeveloped oil and gas reserves*"” Undeveloped oil and gas reserves are reserves of any category that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

* This definition is an abbreviated version of the complete definition set forth in Rule 4-10(a) of Regulation S-X. For the complete definition, see:
http://www.ecfr.gov/cgi-bin/retrieveECFR?gp=1&SID=7aa25d3cede06103c0ecec861362497d&ty=HTML&h=L&n=pt17.3.21

ABRAXAS PETROLEUM CORPORATION
FORM 10 – Q
INDEX

PART I

PART II
OTHER INFORMATION

Table of Contents

Part I
FINANCIAL STATEMENTS

Item 1. Financial Statements

ABRAXAS PETROLEUM CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS
(in thousands)

	September 30, 2015 (Unaudited)	December 31, 2014
Assets		
Current assets:		
Cash and cash equivalents	$—	$3,772
Accounts receivable:		
Joint owners	1,639	5,648
Oil and gas production sales	7,556	15,308
Other	2,816	647
	12,011	21,603
Derivative asset	12,881	12,214
Other current assets	696	843
Total current assets	25,588	38,432
Property and equipment:		
Oil and gas properties, full cost method of accounting:		
Proved	770,415	716,922
Other property and equipment	41,358	40,683
Total	811,773	757,605
Less accumulated depreciation, depletion, and amortization	(527,353)	(434,726)
Total property and equipment, net	284,420	322,879
Deferred financing fees, net	1,807	2,216
Derivative asset	10,353	10,981
Other assets	255	391
Total assets	$322,423	$374,899

See accompanying notes to condensed consolidated financial statements (unaudited).

Table of Contents

ABRAXAS PETROLEUM CORPORATION
CONDENSED CONSOLIDATED BALANCE SHEETS (CONTINUED)
(in thousands, except share data)

	September 30, 2015 (Unaudited)	December 31, 2014
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$25,619	$63,549
Joint interest oil and gas production payable	6,722	14,423
Accrued interest	99	72
Other accrued expenses	1,730	1,006
Derivative liability	—	13
Current maturities of long-term debt	2,300	2,235
Total current liabilities	36,470	81,298
Long-term debt – less current maturities	124,991	76,554
Other liabilities	57	57
Future site restoration	9,847	9,495
Total liabilities	171,365	167,404
Commitments and contingencies (Note 8)		
Stockholders' Equity:		
Preferred stock, par value $.01 per share – authorized 1,000,000 shares; -0- shares issued and outstanding	—	—
Common stock, par value $0.01 per share, authorized 200,000,000 shares; 106,346,001 and 106,186,678 issued and outstanding, respectively	1,064	1,062
Additional paid-in capital	313,025	309,773
Accumulated deficit	(163,031)	(103,340)
Total stockholders' equity	151,058	207,495
Total liabilities and stockholders' equity	$322,423	$374,899

See accompanying notes to condensed consolidated financial statements (unaudited).

ABRAXAS PETROLEUM CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS
(Unaudited)
(in thousands except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Revenues:				
Oil and gas production revenues	$16,075	$43,865	$53,658	$102,521
Other	2	9	24	63
	16,077	43,874	53,682	102,584
Operating costs and expenses:				
Lease operating	5,236	7,131	17,806	18,361
Production taxes	1,569	3,744	5,255	8,786
Depreciation, depletion, and amortization	10,165	13,836	31,044	30,441
Proved property impairment	59,891	—	59,891	—
General and administrative (including stock-based compensation of $835, $582, $3,085 and $2,050, respectively)	2,654	2,379	9,190	7,915
	79,515	27,090	123,186	65,503
Operating (loss) income	(63,438)	16,784	(69,504)	37,081
Other (income) expense:				
Interest income	—	—	(1)	(1)
Interest expense	992	548	2,784	1,927
Amortization of deferred financing fees	161	150	481	779
(Gain) loss on derivative contracts - Realized	(1,745)	534	(6,899)	2,624
(Gain) on derivative contracts - Unrealized	(10,474)	(9,979)	(6,198)	(1,899)
Other	—	(8)	—	(8)
	(11,066)	(8,755)	(9,833)	3,422
(Loss) income from continuing operations before income tax	(52,372)	25,539	(59,671)	33,659
Income tax (expense) benefit	—	—	—	—
Net (loss) income from continuing operations	(52,372)	25,539	(59,671)	33,659
Net (loss) from discontinued operations - net of tax	—	(140)	(20)	(522)
Net (loss) income	$(52,372)	$25,399	$(59,691)	$33,137
Net (loss) income per common share - basic				
Continuing operations	$(0.50)	$0.24	$(0.57)	$0.35
Discontinued operations	—	—	—	(0.01)
	$(0.50)	$0.24	$(0.57)	$0.34
Net (loss) income per common share - diluted				
Continuing operations	$(0.50)	$0.24	$(0.57)	$0.34
Discontinued operations	—	—	—	(0.01)
	$(0.50)	$0.24	$(0.57)	$0.33
Weighted average shares outstanding:				
Basic	104,614	104,408	104,561	96,742

Diluted	104,614	107,671	104,561	99,531

See accompanying notes to condensed consolidated financial statements (unaudited).

Table of Contents

ABRAXAS PETROLEUM CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF
OTHER COMPREHENSIVE INCOME (LOSS)
(Unaudited)
(in thousands)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Net (loss) income	$(52,372)	25,399	$(59,691)	$33,137
Other comprehensive income (loss):				
Foreign currency translation adjustment	—	(35)	—	(67)
Other comprehensive income (loss)	—	(35)	—	(67)
Comprehensive (loss) income	$(52,372)	$25,364	$(59,691)	$33,070

See accompanying notes to condensed consolidated financial statements (unaudited).

Table of Contents

ABRAXAS PETROLEM CORPORATION
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS
(Unaudited)
(in thousands)

	Nine months ended September 30, 2015	2014
Operating Activities		
Net (loss) income	$(59,691)	$33,137
Loss from discontinued operations	(20)	(522)
(Loss) income from continuing operations	(59,671)	33,659
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Change in derivative fair value	(4,662)	(2,383)
Monetization of derivative contracts	4,610	—
Depreciation, depletion, and amortization	31,044	30,441
Proved property impairment	59,891	—
Amortization of deferred financing fees	481	779
Accretion of future site restoration	426	419
Stock-based compensation	3,085	2,050
Changes in operating assets and liabilities:		
Accounts receivable	9,592	3,843
Other assets	283	(151)
Accounts payable and accrued expenses	(44,954)	(10,646)
Net cash provided by continuing operations	125	58,011
Net cash (used in) provided by discontinued operations	(20)	2
Net cash provided by operating activities	105	58,013
Investing Activities		
Capital expenditures, including purchases and development of properties	(52,614)	(137,462)
Proceeds from the sale of oil and gas properties	138	5,999
Net cash used in continuing operations	(52,476)	(131,463)
Net cash provided by discontinued operations	—	335
Net cash used in investing activities	(52,476)	(131,128)
Financing Activities		
Proceeds from long-term borrowings	54,000	64,000
Payments on long-term borrowings	(5,498)	(46,437)
Proceeds from issuance of common stock	—	53,755
Deferred financing fees	(72)	(946)
Exercise of stock options	169	255
Other	—	192
Net cash provided by continuing operations	48,599	70,819
Net cash (used in) discontinued operations	—	(220)
Net cash provided by financing activities	48,599	70,599

10

Table of Contents

	Nine months ended September 30,	
	2015	2014
Effect of exchange rate changes on cash - discontinued operations	—	(3)
Decrease in cash and cash equivalents	(3,772)	(2,519)
Cash and cash equivalents at beginning of period	$3,772	$5,205
Cash and cash equivalents at end of period	$—	$2,686
Supplemental disclosures of cash flow information:		
Interest paid	$2,756	$1,899

See accompanying notes to condensed consolidated financial statements (unaudited).

Table of Contents

ABRAXAS PETROLEUM CORPORATION
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS
(Unaudited)
(tabular amounts in thousands, except per share data)

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, 2014 filed with the SEC on March 13, 2015. 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 condensed 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 condensed 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 period ended September 30, 2015 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, 2014.

Consolidation Principles

The terms “Abraxas,” “Abraxas Petroleum,” “we,” “us,” “our” or the “Company” refer to Abraxas Petroleum Corporation and of its subsidiaries, including Raven Drilling, LLC (“Raven Drilling”).

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 hold 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.

New Accounting Standards and Disclosures

Recent Accounting Developments

Income Statement - Extraordinary and Unusual Items

In January 2015, the Financial Accounting Standards Board (“FASB”) issued Accounting Standards Update (“ASU”) No. 2015-01, Income Statement - Extraordinary and Unusual Items. The ASU removes the concept of extraordinary items from GAAP. Under existing guidance, an entity is required to separately disclose extraordinary items, net of tax, in the income statement after income from continuing operations if an event or transaction is of an unusual nature and occurs infrequently. This separate, net-of-tax presentation will no longer be allowed, and the pronouncement is effective for interim and annual reporting periods beginning after December 15, 2015. This guidance is not expected to have a material impact on the Company’s consolidated financial position, results of operations or cash flows.

Table of Contents

Presentation of Debt Issuance Costs

In April 2015, the FASB issued Simplifying the Presentation of Debt Issuance Costs, Subtopic 835-30 (ASU No. 2015-03), which amends existing guidance to require the presentation of debt issuance costs on the balance sheet as a deduction from the carrying amount of the related debt, instead of an asset. This guidance will be effective for interim and annual reporting periods beginning after December 15, 2015, and early adoption is permitted. Other than the prescribed reclassification of assets to an offset of debt on the consolidated balance sheets, Abraxas does not expect the implementation of ASU 2015-03 to have a material impact on its consolidated financial statements.

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.

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,	
2015	2014	2015	2014
$463	$361	$1,917	$1,475

The following table summarizes the Company’s stock option activity for the nine months ended September 30, 2015 (shares in thousands):

	Number of Shares (thousands)	Weighted Average Option Exercise Price Per Share	Weighted Average Grant Date Fair Value Per Share
Outstanding, December 31, 2014	5,885	$2.88	$2.06
Granted	1,601	$3.22	$2.37
Exercised	(164)	$1.03	$0.71
Cancelled	(433)	$4.45	$3.67
Outstanding, September 30, 2015	6,889	$2.90	$2.06

Additional information related to stock options at September 30, 2015 and December 31, 2014 is as follows:

	September 30, 2015	December 31, 2014
Options exercisable	4,362	4,112

As of September 30, 2015, 470,325 of the vested shares are in the money based on a closing price of $1.28.

As of September 30, 2015, there was approximately $4.2 million of unamortized compensation expense related to outstanding stock options that will be recognized in 2015 through 2018.

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.

Table of Contents

The following table summarizes the Company’s restricted stock activity for the nine months ended September 30, 2015:

	Number of Shares (thousands)	Weighted Average Grant Date Fair Value Per Share
Unvested, December 31, 2014	1,776	$3.43
Granted	—	—
Vested/Released	(118)	3.37
Forfeited	(5)	2.56
Unvested, September 30, 2015	1,653	$3.44

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,	
2015	2014	2015	2014
$372	$221	$1,168	$575

As of September 30, 2015, there was approximately $3.6 million of unamortized compensation expense relating to outstanding restricted shares that will be recognized in 2015 through 2018.

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 the 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 cost ceiling 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, 2015, our net capitalized costs of oil and gas properties exceeded the cost ceiling of our estimated proved reserves by approximately $59.9 million, resulting in the recognition of a proved property impairment of $59.9 million for the quarter ended September 30, 2015. Based on the first-day-of-the-month prices over the eleven months ended November 1, 2015, we anticipate recording another write-down in the carrying value of our oil and gas properties in the fourth quarter of 2015. Further write-downs in subsequent quarters will occur if the trailing 12-month commodity prices continue to fall as compared to the commodity prices used in prior quarters.

Restoration, Removal and Environmental Liabilities

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

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

Table of Contents

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, 2015 and the year ended December 31, 2014:

	September 30, 2015	December 31, 2014
Beginning asset retirement obligation	$9,495	$9,888
New wells placed on production and other	214	444
Deletions related to property disposals and plugging costs	(332)	(1,318)
Accretion expense	426	559
Revisions and other	44	198
Discontinued operations	—	(276)
Ending asset retirement obligation	$9,847	$9,495

2. Income Taxes

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

For the nine months ended September 30, 2015, there was no current or deferred income tax expense or benefit due to loss carryforwards. Valuation allowances have been recorded against such benefits in prior periods.

The Company accounts for uncertain tax positions under the provisions of ASC 740-10. The Company recognizes interest and penalties related to uncertain tax positions in income tax expense. As of September 30, 2015, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years 2004 through 2014 remain open to examination by the tax jurisdictions to which the Company is subject.

At December 31, 2014, the Company had, subject to the limitation discussed below, $150.8 million of net operating loss carryforwards for U.S. tax purposes. The loss carryforward will expire in varying amounts through 2034, if not utilized.

Uncertainties exist as to the future utilization of the operating loss carryforwards under the criteria set forth under ASC 740-10 Income Taxes. Therefore, we have established a valuation allowance of $60.1 million for deferred tax assets at December 31, 2014.

Table of Contents

3. Long-Term Debt

The following is a description of the Company’s debt as of September 30, 2015 and December 31, 2014, respectively:

	September 30, 2015	December 31, 2014
	(In thousands)	
Senior secured credit facility	$120,000	$70,000
Rig loan agreement	3,128	4,456
Real estate lien note	4,163	4,333
	127,291	78,789
Less current maturities	(2,300)	(2,235)
	$124,991	$76,554

Credit Facility

We have a 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, 2015, $120.0 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. At September 30, 2015, we had a borrowing base of $165.0 million. 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 was reaffirmed in August 2015, the next redetermination will be in April 2016. 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 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)0.75%—1.75%, depending on the utilization of the borrowing base, or, if we elect LIBOR plus 1.75%—2.75%, depending on the utilization of the borrowing base. At September 30, 2015, the interest rate on the credit facility was 2.45% 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, 2018. 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 of not more than 4.00 to 1.00. The current ratio is defined as the ratio of consolidated current assets to consolidated current liabilities. For the purposes of this calculation, current assets include the portion of the borrowing base which is undrawn but excludes any cash deposited with 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

Table of Contents

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 defined as the sum of 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 plus expenses incurred in connection with the negotiation, execution, delivery and performance of the Credit Facility plus expenses incurred in connection with any acquisition permitted under the Credit Facility plus expenses incurred in connection with any offering of senior unsecured notes, subordinated debt or equity plus up to $1.0 million of extraordinary expenses in any 12-month period plus extraordinary losses 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, Raven Drilling's rig loan and obligations with respect to surety bonds and derivative contracts.

At September 30, 2015 we were in compliance with all of our debt covenants. As of September 30, 2015, the interest coverage ratio was 19.46 to 1.00, the total debt to EBITDAX ratio was 2.16 to 1.00, and our current ratio was 1.69 to 1.00.

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

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

The credit facility also contains customary events of default, including nonpayment of principal or interest, violations of covenants, cross default and cross acceleration to certain other indebtedness, bankruptcy and material judgments and liabilities.

Rig Loan Agreement

On September 19, 2011, Raven Drilling entered into a rig loan agreement, secured by our Oilwell 2,000 HP diesel electric drilling rig (the "Collateral"). The original principal amount of the note was $7.0 million and bears interest at 4.26%. The note is payable in monthly interest and principal payments in the amount of $179,695. Subject to earlier prepayment provisions and events of default, the stated maturity date of the note is February 14, 2017. As of September 30, 2015 and December 31, 2014, $3.1 million and $4.5 million, respectively, 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

We have a real estate lien note secured by a first lien deed of trust on the property and improvements which serves as our corporate headquarters. The note bears interest at a fixed rate of 4.25% and is payable in monthly installments of

$34,354. Beginning August 20, 2018, the interest rate will adjust to the bank's then current prime rate plus 1.00% with a maximum rate of 7.25%. The maturity date of the note is July 20, 2023. As of September 30, 2015 and December 31, 2014, $4.2 million and $4.3 million, respectively, was outstanding on the note.

Table of Contents

4. Earnings per Share

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
	(In thousands, except per share data)			
Numerator:				
Net (loss) income from continuing operations	$(52,372)	$25,539	$(59,671)	$33,659
Net loss from discontinued operations	—	(140)	(20)	(522)
	(52,372)	25,399	(59,691)	33,137
Denominator:				
Denominator for basic earnings per share – weighted-average common shares outstanding	104,614	104,408	104,561	96,742
Effect of dilutive securities: Stock options and restricted shares	—	3,263	—	2,789
Denominator for diluted earnings per share – adjusted weighted-average shares and assumed exercise of options and restricted shares	104,614	107,671	104,561	99,531
Net income (loss) per common share - basic				
Continuing operations	$(0.50)	$0.24	$(0.57)	$0.35
Discontinued operations	—	—	—	(0.01)
	$(0.50)	$0.24	$(0.57)	$0.34
Net income (loss) per common share - diluted				
Continuing operations	$(0.50)	$0.24	$(0.57)	$0.34
Discontinued operations	—	—	—	(0.01)
	$(0.50)	$0.24	$(0.57)	$0.33

Basic earnings per share, excluding any dilutive effects of stock options and unvested restricted stock, is computed by dividing net income (loss) available to common stockholders by the weighted average number of common shares outstanding for the period. Diluted income (loss) per share is computed similar to basic; however diluted income (loss) per share reflects the assumed conversion of all potentially dilutive securities. For the three and nine months ended September 30, 2015, 1,971 and 2,505 potential shares related to stock options and unvested restricted shares, respectively were excluded from the calculation of diluted income (loss) per share since their inclusion would have been anti-dilutive due to losses incurred in the periods.

5. Hedging Program and Derivatives

The derivative instruments we utilize are based on index prices that may and often do differ from the actual oil and gas prices realized in our operations. 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. There are no netting agreements relating to these derivative contracts and there is no policy to offset.

The following table sets forth the summary position of our derivative contracts as of September 30, 2015:

Fixed price swaps:

	Oil - WTI	Gas

Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (Mcf)	Swap Price (per Mcf)
2015 (October - December)	—	$—	1,450	$4.04
2016	948	$84.10	—	$—
2017	608	$78.55	—	$—

Table of Contents

Collar contracts combined with short puts (three-way collar)

Contract Periods	Oil - WTI Daily Volume (Bbl)	Floor (Long Put)	Ceiling (Short Call)	Short Put
2015 (October - December)	2,000	$55.00	$70.00	$—
2016	1,000	$60.00	$71.00	$45.00

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

Fair Value of Derivative Instruments as of September 30, 2015

	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	$12,881	Derivatives – current	$—
Commodity price derivatives	Derivatives – long-term	10,353	Derivatives – long-term	—
		$23,234		$—

Fair Value of Derivative Instruments as of December 31, 2014

	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	$12,214	Derivatives – current	$13
Commodity price derivatives	Derivatives – long-term	10,981	Derivatives – long-term	—
		$23,195		$13

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

6. Financial Instruments

The Company applies ASC 820-10 which defines fair value, establishes a framework for measuring fair value, establishes a fair value hierarchy based on the quality of inputs used to measure fair value and enhances disclosure requirements for fair value measurements.

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

- Level 1 – inputs to the valuation methodology are quoted prices (unadjusted) for identical assets or liabilities in active markets.
- Level 2 - inputs to the valuation methodology include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the

financial instrument.

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

A financial instrument's categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. The Company is further required to assess the creditworthiness of the counter-party to the derivative contract. The results of the assessment of non-performance risk, based on the counter-party's credit risk, could result in an adjustment of the carrying value of the derivative instrument. The following tables sets forth information about the Company's assets and liabilities measured at fair value on a recurring basis as of September 30, 2015 and December 31, 2014, and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value (in thousands):

Table of Contents

	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, 2015
Assets:				
NYMEX Fixed Price Derivative contracts	$—	$17,889	$—	$17,889
NYMEX Collars	—	5,345	—	5,345
Total Assets	$—	$23,234	$—	$23,234
Liabilities:				
NYMEX Fixed Price Derivative contracts	$—	$—	$—	$—
Total Liabilities	$—	$—	$—	$—

	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, 2014
Assets:				
NYMEX Fixed Price Derivative contracts	$—	$23,195	$—	$23,195
Total Assets	$—	$23,195	$—	$23,195
Liabilities:				
NYMEX Fixed Price Derivative contracts	$—	$13	$—	$13
Total Liabilities	$—	$13	$—	$13

The Company’s derivative contracts consist of NYMEX-based fixed price swaps and three-way collar contracts. Under fixed price swaps, we receive a fixed price for our production and pay a variable market price to the contract counter-party. Three-way collar contracts combine a long put, a short put and a short call. Under a collar, we pay the counterparty if the market price is above the ceiling price (short call) and the counterparty pays us if the market price is below the floor price (long put). The use of the long put combined with a short put allows us to sell a call at a higher price, thus establishing a higher ceiling and limits our exposure to future settlement payments while also restricting our downward risk to the difference between the long put and the short put if the price drops below the price of the short put. This allows us to settle our contracts for the market price plus the spread between the short put and the long put in a case where the market price has fallen below the short put fixed price. The NYMEX-based fixed price derivative contracts and three-way collars are indexed to NYMEX futures contracts, which are actively traded, for the underlying commodity and are commonly used in the energy industry. A number of financial institutions and large energy companies act as counter-parties to these type of derivative contracts. As the fair value of these derivative contracts is based on a number of inputs, including contractual volumes and prices stated in each derivative contract, current and future NYMEX commodity prices, and quantitative models that are based upon readily observable market parameters that are actively quoted and can be validated through external sources, we have characterized these derivative contracts as Level 2. In order to verify the third party valuation, we enter the various inputs into a model and compare our results to the third party for reasonableness.

Other Financial Instruments

The carrying amounts of our cash, cash equivalents, restricted cash, accounts receivable, accounts payable, and accrued liabilities approximate fair value because of the short-term maturities and/or liquid nature of these assets and liabilities. The carrying value of our debt approximates fair value as the interest rates are market rates and this debt is considered Level 2.

Table of Contents

7. Discontinued Operations

On October 31, 2014, the Company closed on the sale of its Canadian subsidiary, Canadian Abraxas Petroleum, ULC ("Canadian Abraxas"). The sale was based on management's decision to discontinue Canadian operations due to continuing losses.

Canadian Abraxas revenue, reported in discontinued operations for the three and nine months ended September 30, 2014 was $0.3 million and $1.1 million, respectively. Canadian Abraxas net loss, reported in discontinued operations for the three and nine months ended September 30, 2014 was $0.1 million and $0.5 million, respectively.

8. Commitments and Contingencies

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, 2015, the Company was not involved in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on its financial position or results of operations.

Table of Contents

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, 2014 filed with the SEC on March 13, 2015. Excluded from this discussion are the results of Canadian Abraxas which was sold on October 31, 2014. The results of these foreign operations are included as discontinued operations in the accompanying Condensed Consolidated Financial Statements and Notes thereto.

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, 2014.

General

We are an independent energy company primarily engaged in the acquisition, exploration, exploitation, development and production of oil and gas in the United States. We focus on assets with a high working interest and low geologic risk as well as operational and infrastructure control. We seek strong full cycle rate of return and low risk exploitable upside using the Company's operating experience. We believe that we have a number of development opportunities on our properties and 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 four of the last five years, there can be no assurance that operating income and net earnings will be achieved in future periods. Our financial results depend upon many factors which significantly affect our results of operations including the following:

- commodity prices and the effectiveness of our hedging arrangements;
- the level of total sales volumes of oil, gas and NGL;
- the availability of and our ability to raise additional capital resources and provide liquidity to meet cash flow needs;
- the level of and interest rates on borrowings; and
- the level and success of exploration and development activity

Commodity Prices and Hedging Arrangements. The results of our operations are highly dependent upon the prices received for our oil and gas production. The prices we receive for our production are dependent upon spot market prices, differentials and the effectiveness of our derivative contracts, which we sometimes refer to as hedging arrangements. Substantially all of our sales of oil and gas are made in the spot market, or pursuant to contracts based on spot market prices, and not pursuant to long-term, fixed-price contracts. Accordingly, the prices received for our oil and gas production are dependent upon numerous factors beyond our control. Significant declines in prices for oil and gas could have a material adverse effect on our financial condition, results of operations, cash flows and quantities of reserves recoverable on an economic basis.

Oil and gas prices have been volatile, and this volatility is expected to continue. As a result of the many uncertainties associated with the world political environment, worldwide demand for, and supplies of oil, NGL and gas, the availability of other worldwide energy supplies and the relative competitive relationships of the various energy sources in the view of consumers, we are unable to predict what changes may occur in oil, NGL, and gas prices in the future. The market price of oil and condensate, NGL and gas in 2015 have impacted the amount of cash generated from operating activities, and have in turn impacted our financial position.

During the nine months ended September 30, 2015, the NYMEX future price for oil averaged $50.98 per barrel as compared to $99.62 per barrel in 2014. During the nine months ended September 30, 2015, the NYMEX future spot price for gas averaged $2.76 per MMBtu compared to $4.41 per MMBtu in 2014. Prices closed on September 30, 2015 at $45.09 per Bbl of oil and $2.52 per MMBtu of gas, compared to closing on September 30, 2014 at $91.16 per Bbl of oil and $4.12 per MMBtu of gas. If

Table of Contents

commodity prices remain at these levels or continue to decline, our revenue and cash flow from operations will also likely decline. In addition, lower commodity prices could also reduce the amount of oil and gas that we can produce economically. If oil and gas prices remain depressed or continue to decline, our revenues, profitability and cash flow from operations will also likely decrease which could cause us to alter our business plans, including reducing our drilling activities. Such declines have required, and in future periods could also require us to write down the carrying value of our oil and gas assets which would also cause a reduction in net income.

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 nine months ended September 30, 2015 and 2014:

	Oil - NYMEX		Gas - NYMEX	
	2015	2014	2015	2014
Average realized price (1)	$42.94	$90.60	$2.16	$4.37
Average NYMEX price	50.98	99.62	2.76	4.41
Differential	$(8.04)	$(9.02)	$(0.60)	$(0.04)

(1) Excludes the impact of derivative activities.

At September 30, 2015, our derivative contracts consisted of fixed price swaps and three-way collar contracts. Under fixed price swaps, we receive a fixed price for our production and pay a variable market price to the contract counter-party. Three-way collar contracts combine a long put, a short put and a short call. Under a collar, we pay the counterparty if the market price is above the ceiling price (short call) and the counterparty pays us if the market price is below the floor price (long put). The use of the long put combined with a short put allows us to sell a call at a higher price, thus establishing a higher ceiling and limits our exposure to future settlement payments while also restricting our downward risk to the difference between the long put and the short put if the price drops below the price of the short put. This allows us to settle our contracts for the market price plus the spread between the short put and the long put in a case where the market price has fallen below the short put fixed price.

Our hedging arrangements equate to approximately 51% of the estimated oil production from our net proved developed producing reserves (based on our reserve estimates as of June 30, 2015) through December 31, 2015, 74% in 2016, and 24% in 2017. By removing a portion of price volatility on our future oil and gas production, we believe we will mitigate, but not eliminate, the potential effects of changing commodity prices on our cash flow from operations for those periods. However, when prevailing market prices are higher than our contract prices, we will not realize increased cash flow on the portion of the production that has been hedged. We have in the past and will in the future sustain realized and unrealized losses on our derivative contracts if market prices are higher than our contract prices. Conversely, when prevailing market prices are lower than our contract prices, we will sustain realized and unrealized gains on our commodity derivative contracts. For the nine months ended September 30, 2015, we incurred a realized gain of $6.9 million, and an unrealized gain of $6.2 million. For the nine months ended September 30, 2014, we incurred a realized loss of $2.6 million and an unrealized gain of $1.9 million. We have not designated any of these derivative contracts as a hedge as prescribed by applicable accounting rules.

Table of Contents

The following table sets forth our derivative contracts at September 30, 2015:

Fixed Price Swaps:

Contract Periods	Oil - WTI Daily Volume (Bbl)	Swap Price (per Bbl)	Gas Daily Volume (Mcf)	Swap Price (per Mcf)
2015 (October - December)	—	$—	1,450	$4.04
2016	948	$84.10	—	$—
2017	608	$78.55	—	$—

Collar contracts combined with short puts (three-way collar)

Contract Periods	Oil - WTI Daily Volume (Bbl)	Floor (Long Put)	Ceiling (Short Call)	Short Put
2015 (October - December)	2,000	$55.00	$70.00	$—
2016	1,000	$60.00	$71.00	$45.00

At September 30, 2015, the aggregate fair market value of our commodity derivative contracts was an asset of approximately $23.2 million. We have in the past, and may in the future, monetize our derivative contracts in order to provide us with liquidity. In May 2015, we monetized our July - December 2015 fixed price oil swaps for net proceeds of approximately $4.6 million. The proceeds were used to repay indebtedness under the credit facility.

Production Volumes. Our proved reserves will decline as oil and gas is produced, unless we find, acquire or develop additional properties containing proved reserves or conduct successful exploration and development activities. Based on the reserve information set forth in our reserve estimates as of December 31, 2014, we anticipate our Proved Developed Producing reserves to decline 20.1%, 13.1% and 10.1% in 2016, 2017 and 2018, respectively. There after our reserves are expected to decline an estimated 7.4% annually. These rates of decline are estimates and actual production declines could be materially higher. While we have had some success in finding, acquiring and developing additional reserves, we have not always been able to fully replace the production volumes lost from natural field declines and property sales. Our ability to acquire or find additional reserves in the future will be dependent, in part, upon the amount of available funds for acquisition, exploration and development projects.

We had capital expenditures during the nine months ended September 30, 2015 of $52.6 million related to our exploration and development activities. We have a capital expenditure budget for 2015 of $70.0 million. Substantially all of our 2015 budget will be spent on unconventional horizontal oil wells in the Bakken/Three Forks and Eagle Ford. The 2015 capital expenditure budget is subject to change depending upon a number of factors, including prevailing and anticipated prices for oil and gas, the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, the availability of sufficient capital resources, the results of our exploitation efforts, and our ability to obtain permits for drilling locations.

Table of Contents

The following table presents historical net production volumes for the three and nine months ended September 30, 2015 and 2014:

	Three months ended September 30,		Nine months ended September 30,	
	2015	2014	2015	2014
Total production (MBoe)	552	645	1,643	1,463
Average daily production (Boepd)	6,004	7,010	6,020	5,361
% Oil/ NGL	77 %	78 %	77 %	76 %

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 appropriate opportunities presents itself, the sale of debt or equity securities, selling assets or monetizing our derivative instruments, although we may not be able to complete any financing on terms acceptable to us, if at all. As of September 30, 2015 we had approximately $45.0 million of availability under our credit facility.

Borrowings and Interest. At September 30, 2015, we had a total of $120.0 million outstanding under our credit facility and total indebtedness of $127.3 million (including the current portion). If interest expense increases as a result of higher interest rates or increased borrowings, more cash flow from operations would be used to meet debt service requirements. As a result, we would need to increase our cash flow from operations in order to fund the development of our drilling opportunities which, in turn, will be dependent upon the level of our production volumes and commodity prices.

Exploration and Development Activity. We believe that our high quality asset base, high degree of operational control and inventory of drilling projects position us for future growth. At December 31, 2014, we operated properties accounting for approximately 92% 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. Over the five years ended December 31, 2014, we drilled or participated in 146 gross (54.2 net) wells of which 97% were productive.

Our future oil and gas production, and therefore our success, is highly dependent upon our ability to find, acquire and develop additional reserves that are profitable to produce. The rate of production from our oil and gas properties and our proved reserves will decline as our reserves are produced unless we acquire additional properties containing proved reserves, conduct successful development and exploration activities or, through engineering studies, identify additional behind-pipe zones or secondary recovery reserves. We cannot assure you that our exploration and development activities will result in increases in our proved reserves. If our proved reserves decline in the future, our production may also decline and, consequently, our cash flow from operations and the amount that we are able to borrow under our credit facility may also decline. In addition, approximately 58% of our estimated proved reserves at December 31, 2014 were undeveloped. By their nature, estimates of undeveloped reserves are less certain. Recovery of such reserves will require significant capital expenditures and successful drilling operations. We may be unable to acquire or develop additional reserves, in which case our results of operations and financial condition could be adversely affected.

Operational Update

Williston Basin

On the Ravin Northwest pad at our North Fork prospect, in McKenzie County, North Dakota, the Ravin 8H, Sten-Rav 1H and Stenehjem 5H were successfully fracture stimulated and are currently being drilled-out. We also successfully drilled and cased the Stenehjem 14H-15H and are currently drilling the lateral section of the Stenehjem 13H. This will be followed by the lateral sections of the Stenehjem 10H-12H. We own a working interest of approximately 74% and 78% in the Ravin Northwest wells and Stenehjem 10H-15H, respectively.

Gulf Coast

At our Portilla Field, in San Patricio County, Texas, the Company is commencing a pilot program to test Glori Energy's (NASDAQ: GLRI) microbial enhanced oil recovery (EOR) technology known as AERO. Glori Energy estimates that the deployment of the technology can potentially recover an additional 9-12% of the original oil in place or up to 20% of the remaining oil in analogous fields. The Portilla Field was discovered by the Superior Oil Company in 1950 and has cumulative production

Table of Contents

of approximately 80 million barrels of oil from various sandstone reservoirs from about 3,500 to 9,600 feet. We acquired a 100% working interest in the field from Mobil Oil Corporation in 1992. The three main reservoirs at depths of 7300 - 8100 feet are the objectives of the AERO technology, and we estimate those reservoirs originally contained about 125 million barrels of oil. To date the reservoirs have produced about 70 million barrels of oil and continues to steadily produce over 200 BOPD. These main reservoirs produce with a natural water drive mechanism, which permits relatively inexpensive deployment of the AERO technology. None of the field has been subjected to other enhanced oil recovery methods, such as CO_2. If the pilot is successful, full field deployment will commence in 2016.

Table of Contents

Results of Operations

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2015	2014	2015	2014
Operating revenue (1):				
Oil sales	$14,414	$38,410	$47,240	$88,289
Gas sales	1,345	3,233	4,844	9,118
NGL sales	316	2,222	1,574	5,114
Other	2	9	24	63
Total operating revenues	$16,077	$43,874	$53,682	$102,584
Operating (loss) income	(63,438)	16,784	(69,504)	37,081
Oil sales (MBbls)	365	436	1,100	975
Gas sales (MMcf)	750	836	2,246	2,087
NGL sales (MBbls)	62	69	169	141
Oil equivalents (MBoe)	552	645	1,643	1,463
Average oil sales price (per Bbl)(1)	$39.50	$88.02	$42.94	$90.60
Average gas sales price (per Mcf)(1)	$1.79	$3.87	$2.16	$4.37
Average NGL sales price (per Bbl)	$5.07	$32.11	$9.32	$36.25
Average oil equivalent sales price (Boe)	$29.10	$68.02	$32.65	$70.05

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

Comparison of Three Months Ended September 30, 2015 to Three Months Ended September 30, 2014

Operating Revenue. During the three months ended September 30, 2015, operating revenue decreased to $16.1 million from $43.9 million for the same period of 2014. The decrease in revenue was primarily due to significantly lower prices for all products as well as lower sales volumes. Lower oil, gas and NGL sales volumes negatively impacted revenue by $3.0 million for the three months ended September 30, 2015. Significant decreases in prices for all products had a negative impact of $24.8 million on operating revenue for the three months ended September 30, 2015.

Oil sales volumes decreased to 365 MBbl during the three months ended September 30, 2015 from 436 MBbl for the same period of 2014. The decrease in oil sales was primarily due to natural field declines, in addition, some of our wells were shut in while performing completion operations on the same multi well pad during the quarter. Production decreases were partially offset by new wells brought on line since the third quarter of 2014 which contributed 177 MBbl for the three months ended September 30, 2015. Gas sales volumes decreased to 750 MMcf for the three months ended September 30, 2015 from 836 MMcf for the same period of 2014. The decrease in gas production was due to natural declines as well as pipeline constraints. The decrease was partially offset by new wells brought on line since September 30, 2014 which contributed 135 MMcf for the three months ended September 30, 2015. NGL sales volumes decreased to 62 MBbl for the three months ended September 30, 2015 from 69 MBbl for the same period of 2014. The decrease in NGL sales was primarily due to lower gas production. NGL sales were also negatively impacted by plant and pipeline issues in North Dakota and West Texas.

Lease Operating Expenses (“LOE”). LOE for the three months ended September 30, 2015 decreased to $5.2 million from $7.1 million for the same period in 2014. Due to the decline in commodity prices, there has been a decrease in the cost of services. Additionally we have focused on lowering LOE and shutting in marginal wells. We have also significantly reduced our non-recurring projects. LOE per Boe for the three months ended September 30, 2015 was $9.48 compared to $11.06 for the same period of 2014. The decrease per Boe was due to lower costs incurred for the three months ended September 30, 2015 as compared to the same period of 2014 partially offset by lower sales volumes.

Table of Contents

Production and Ad Valorem Taxes. Production and ad valorem taxes for the three months ended September 30, 2015 decreased to $1.6 million from $3.7 million for the same period of 2014. The decrease was due to lower commodity prices and lower sales volumes.
General and Administrative ("G&A") Expenses. G&A expenses, excluding stock-based compensation, for the three months ended September 30, 2015 and September 30, 2014 was constant at $1.8 million. G&A expense per Boe, excluding stock-based compensation, was $3.29 for the quarter ended September 30, 2015 compared to $2.79 for the same period of 2014. The increase per Boe was primarily due to lower sales volumes.
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 three months ended September 30, 2015 stock-based compensation expense was $0.8 million compared to $0.6 million in 2014. The increase was primarily due to options granted in March 2015 and director options granted in May 2015.
Depreciation, Depletion and Amortization ("DD&A") Expenses. DD&A expense for the three months ended September 30, 2015 decreased to $10.2 million from $13.8 million for the same period of 2014. The decrease was primarily the result of a further decrease in future development costs in our September 30, 2015 reserve report. DD&A expense per Boe for the three months ended September 30, 2015 was $18.40 compared to $21.45 in 2014.
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, 2015, our net capitalized costs of oil and gas properties exceeded the present value of our estimated proved reserves by approximately $59.9 million, resulting in the recognition of a proved property impairment of the same amount. Based on the first-day-of-the-month prices over the eleven months ended November 1, 2015, we anticipate recording another write-down in the carrying value of our oil and gas properties in the fourth quarter of 2015. Further write-downs in subsequent quarters will occur if the trailing 12-month commodity prices continue to fall as compared to the commodity prices used in prior quarters.

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, 2015 increased to $1.0 million from $0.5 million for the same period of 2014. The increase was primarily due to higher debt levels in 2015 as compared to the same period of 2014.

(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 three way collar contracts. The estimated value of our commodity derivative contracts was an asset of approximately $23.2 million as of September 30, 2015. 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, 2015, we realized a gain on our commodity derivative contracts of $1.7 million and an unrealized gain of $10.5 million on our commodity derivative contracts. For the three months ended September 30, 2014, we realized a loss on our commodity derivative contracts of $0.5 million and we incurred an unrealized gain of $10.0 million on our commodity derivative contracts.
Income Tax Expense. For the three months ended September 30, 2015 and 2014 there was no income tax expense recognized as a result of NOL carryforwards and a net loss in the period ended September 30, 2015.

Table of Contents

Comparison of Nine Months Ended September 30, 2015 to Nine Months Ended September 30, 2014

Operating Revenue. During the nine months ended September 30, 2015, operating revenue decreased to $53.7 million from $102.6 million for the same period of 2014. The decrease in revenue was primarily due to lower prices for all products partially offset by increased sales volumes. Lower realized commodity prices had a negative impact on revenue of $54.9 million, of which $46.4 million was attributable to oil. Higher sales volumes contributed $6.0 million to operating revenue. Oil sales volumes increased to 1,100 MBbl during the nine months ended September 30, 2015 from 975 MBbl for the same period of 2014. The increase in oil sales was due to new wells being brought on line offset by natural field declines. New wells contributed 434 MBbl for the nine months ended September 30, 2015. Gas sales volumes increased to 2,246 MMcf for the nine months ended September 30, 2015 from 2,087 MMcf for the same period of 2014. The increase in gas sales was due to new wells brought on line offset by natural field declines. New wells brought onto production contributed 298 MMcf for the nine months ended September 30, 2015. NGL sales volumes increased to 169 MBbl for the nine months ended September 30, 2015 from 141 MBbl for the same period of 2014. The increase in NGL sales was primarily due to a higher percentage of our gas production from West Texas, North Dakota and the Eagle Ford that has a higher NGL content.

LOE. LOE for the nine months ended September 30, 2015 decreased to $17.8 million from $18.4 million for the same period of 2014. The decrease in 2015 was due to lower non-recurring LOE in 2015 as compared to 2014, as well as reduced cost of services. LOE per Boe for the nine months ended September 30, 2015 was $10.83 compared to $12.55 for the same period of 2014. The decrease per Boe was due to lower service costs offset by higher sales volumes for the nine months ended September 30, 2015 as compared to the same period of 2014.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the nine months ended September 30, 2015 decreased to $5.3 million from $8.8 million for the same period of 2014. The decrease was primarily the result of lower commodity prices for the nine months ended September 30, 2015 as compared to the same period of 2014.

G&A Expenses. G&A expenses, excluding stock-based compensation, increased to $6.1 million for the first nine months of 2015 from $5.9 million for the same period of 2014. The increase in G&A expense was primarily related to an increase in legal and professional fees and insurance. G&A expense per Boe was $3.71 for the nine months ended September 30, 2015 compared to $4.01 for the same period of 2014. The decrease per Boe was primarily due to higher cost and increased volumes in the first nine months of 2015 compared to the same period in 2014.

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, 2015 stock based compensation was $3.1 million as compared to $2.1 million for the same period of 2014. The increase was primarily due to option grants in March 2015 and May 2015.

DD&A Expenses. DD&A expense for the nine months ended September 30, 2015 increased to $31.0 million from $30.4 million for same period of 2014. The increase was primarily the result of increased production volumes, offset by a decrease in the depletion base in 2015 as compared to 2014. The decrease in the depletion base was due to lower future development cost in our September 30, 2015 reserve report. Our DD&A expense per Boe for the nine months ended September 30, 2015 was $18.89 compared to $20.80 in 2014.

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, 2015, our net capitalized costs of oil and gas properties exceeded the present value of our estimated proved reserves by approximately $59.9 million, resulting in the recognition of a proved property impairment of the same amount. Based on the first-day-of-the-month prices over the eleven months ended November 1, 2015, we anticipate recording another write-down in the carrying value of our oil and gas properties in the fourth quarter of 2015. Further write-downs in subsequent quarters will occur if the trailing 12-month commodity prices continue to fall as compared to the commodity prices used in prior quarters.

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

Table of Contents

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, 2015 was $2.8 million as compared to $1.9 million for the same period of 2014. The increase in 2015 was due to higher levels of debt as compared to the same period of 2014.

Loss (Gain) on Derivative Contracts. We account for derivative contract gains and losses based on realized and unrealized amounts. The realized derivative gains or losses are determined by actual derivative settlements during the period. Unrealized gains and losses are based on the periodic mark to market valuation of derivative contracts in place. Our derivative contract transactions do not qualify for hedge accounting as prescribed by ASC 815; therefore, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period. Our derivative contracts consist of commodity swaps and three way collar contracts. The net estimated value of our commodity derivative contracts was an asset of approximately $23.2 million as of September 30, 2015. 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, 2015, we realized a gain on our commodity derivative contracts of $6.9 million and an unrealized gain of $6.2 million. For the nine months ended September 30, 2014, we realized a loss on our commodity derivative contracts of $2.6 million and incurred an unrealized gain of $1.9 million.

Income Tax Expense. For the nine months ended September 30, 2015 and 2014 there was no income tax expense recognized as a result of NOL carryforwards and a net loss in the period ended September 30, 2015.

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

The amount of capital expenditures we are able to make has a direct impact on our ability to increase cash flow from operations and, thereby, will directly affect our ability to service our debt obligations and to grow the business through the development of existing properties and the acquisition of new properties.

Our principal sources of capital are cash flow from operations, borrowings under our credit facility, cash on hand, proceeds from the sale of properties, and if appropriate opportunities are available, selling of debt or equity securities, selling assets or monetizing derivative contracts, although we may not be able to complete any of such transactions on terms acceptable to us, if at all.

Capital Expenditures. Capital expenditures for the nine months ended September 30, 2015 and 2014 were $52.6 million and $137.5 million, respectively.

The table below sets forth the components of these capital expenditures:

	Nine months ended September 30,	
	2015	2014
	(In thousands)	
Expenditure category:		
Exploration/Development	$51,939	$136,545
Facilities and other	675	917
Total	$52,614	$137,462

During the nine months ended September 30, 2015 and 2014 our expenditures were primarily for development of our existing properties. We anticipate making capital expenditures in 2015 of $70.0 million. The 2015 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

Table of Contents

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 continue to remain at depressed levels or decline further, our costs of operations increase or if our production volumes decrease, our cash flows will decrease which may result in a reduction of the capital expenditure budget. If we decrease our capital expenditure budget, we may not be able to offset oil and gas production decreases caused by natural field declines.

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

	Nine months ended September 30, 2015	2014
	(In thousands)	
Net cash provided by operating activities	$125	$58,011
Net cash used in investing activities	(52,476)	(131,463)
Net cash provided by financing activities	48,599	70,819
Total	$(3,752)	$(2,633)

Operating activities for the nine months ended September 30, 2015 provided $0.1 million in cash compared to providing $58.0 million in the same period of 2014. Non-cash expense items and, net changes in operating assets and liabilities accounted for most of these funds. Investing activities used $52.5 million during the nine months ended September 30, 2015 compared to using $131.5 million for the same period of 2014. Funds used during the nine months ended September 30, 2015 and 2014 were primarily for the development of our existing properties. Financing activities provided $48.6 million for the nine months ended September 30, 2015 compared to providing $70.8 million for the same period of 2014. Funds provided during the nine months ended September 30, 2015 were primarily proceeds from borrowings under our credit facility. Funds provided during the nine months ended September 30, 2014 were primarily proceeds from a public offering of common stock offset by payments on our credit facility.

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 appropriate opportunities are available, selling of debt or equity securities, and selling assets or monetizing derivative instruments, although we may not be able to complete any such transactions on terms acceptable to us, if at all.

Cash from operating activities is dependent upon commodity prices and production volumes. Depressed commodity prices have reduced, and further decreases in commodity prices from current levels could reduce our cash flows from operations. This could cause us to alter our business plans, including reducing our exploration and development plans. Unless we otherwise expand and develop reserves, our production volumes may decline as reserves are produced. In the future we may continue to sell producing properties, which could further reduce our production volumes. To offset the loss in production volumes resulting from natural field declines and sales of producing properties, we must conduct successful exploration and development activities, acquire additional producing properties or identify and develop additional behind-pipe zones or secondary recovery reserves. We believe our numerous drilling opportunities will allow us to increase our production volumes; however, our drilling activities are subject to numerous risks, including the risk that no commercially productive oil and gas reservoirs will be found. 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 58% of our total estimated proved reserves at December 31, 2014 were classified as undeveloped.

We have in the past, and may in the future, sell producing properties. We have also sold debt and equity securities in the past, and may sell additional debt and equity securities in the future when the opportunity presents itself.

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, 2015:

Table of Contents

	Payments due in twelve month periods ending:				
Contractual Obligations (In thousands)	Total	September 30, 2016	September 30, 2017-2018	September 30, 2019-2020	Thereafter
Long-term debt (1)	$127,291	$2,300	$121,572	$552	$2,867
Interest on long-term debt (2)	9,251	3,208	5,475	272	296
Lease obligations (3)	55	48	7	—	—
Total	$136,597	$5,556	$127,054	$824	$3,163

(1) These amounts represent the balances outstanding under our credit facility, the rig loan agreement and the real estate lien note. These payments assume that we will not borrow additional funds.
(2) Interest expense assumes the balances of long-term debt at the end of the period and current effective interest rates.
(3) Lease on office space in Dickinson, North Dakota, which expires on October 31, 2016, office space in Lusk, Wyoming, which will expire on December 31, 2016 and office space in Denver, Colorado which will expire on December 31, 2016.

We maintain a reserve for costs associated with the retirement of tangible long-lived assets. At September 30, 2015, our reserve for these obligations totaled $9.8 million for which no contractual commitments exist. For additional information relating to this obligation, see Note 1 of the Notes to Consolidated Financial Statements.

Off-Balance Sheet Arrangements. At September 30, 2015 we had no existing off-balance sheet arrangements, as defined under SEC regulations, that have, or are reasonably likely to have a current or future material effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that are material to investors.

Contingencies. From time to time, we are involved in litigation relating to claims arising out of our operations in the normal course of business. At September 30, 2015, we were not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on us.

Other obligations. We make and will continue to make substantial capital expenditures for the acquisition, exploration, development and production of oil and gas. In the past, we have funded our operations and capital expenditures primarily through cash flow from operations, borrowings under our credit facility, cash on hand, proceeds from the sale of properties, sales of debt and equity securities and other sources. Given our high degree of operating control, the timing and incurrence of operating and capital expenditures is largely within our discretion.

Long-Term Indebtedness.

Long-term debt consisted of the following:

	September 30, 2015	December 31, 2014
	(In thousands)	
Credit facility	$120,000	$70,000
Rig loan agreement	3,128	4,456
Real estate lien note	4,163	4,333
	127,291	78,789
Less current maturities	(2,300)	(2,235)
	$124,991	$76,554

Credit Facility

We have a 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, 2015, $120.0 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. At September 30, 2015 we had a borrowing base of $165.0 million. 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 was reaffirmed in August 2015, the next redetermination will be in April 2016.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 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) 0.75%—1.75%, depending on the utilization of the borrowing base, or, if we elect LIBOR plus 1.75%—2.75%, depending on the utilization of the borrowing base. At September 30, 2015, the interest rate on the credit facility was 2.45% 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, 2018. 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 of not more than 4.00 to 1.00. The current ratio is defined as the ratio of consolidated current assets to consolidated current liabilities. For the purposes of this calculation, current assets include the portion of the borrowing base which is undrawn but excludes any cash deposited with 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 defined as the sum of 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 plus expenses incurred in connection with the negotiation, execution, delivery and performance of the Credit Facility plus expenses incurred in connection with any acquisition permitted under the Credit Facility plus expenses incurred in connection with any offering of senior unsecured notes, subordinated debt or equity plus up to $1.0 million of extraordinary expenses in any 12-month period plus extraordinary losses 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, Raven Drilling's rig loan and obligations with respect to surety bonds and derivative contracts.

At September 30, 2015, we were in compliance with all of our debt covenants. As of September 30, 2015, the interest coverage ratio was 19.46 to 1.00, the total debt to EBITDAX ratio was 2.16 to 1.00, and our current ratio was 1.69 to

1.00.

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

- incur or guarantee additional indebtedness;
- transfer or sell assets;
- create liens on assets;
- engage in transactions with affiliates other than on an “arm’s length” basis;
- make any change in the principal nature of our business; and
- permit a change of control.

The credit facility also contains customary events of default, including nonpayment of principal or interest, violations of covenants, cross default and cross acceleration to certain other indebtedness, bankruptcy and material judgments and liabilities.

Rig Loan Agreement

On September 19, 2011 Raven Drilling entered into a rig loan agreement, secured by our Oilwell 2,000 HP diesel electric drilling rig (the "Collateral"). The principal amount of the note was $7.0 million and bears interest at 4.26%. The note is payable in monthly interest and principal payments in the amount of $179,695. Subject to earlier prepayment provisions and events of default, the stated maturity date of the note is February 14, 2017. As of September 30, 2015 and December 31, 2014, $3.1 million and $4.5 million, respectively, 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

We have a real estate lien note secured by a first lien deed of trust on the property and improvements which serves as our corporate headquarters. The note bears interest at a fixed rate of 4.25% and is payable in monthly installments of $34,354. Beginning August 20, 2018, the interest rate will adjust to the bank's then current prime rate plus 1.00% with a maximum rate of 7.25%. The maturity date of the note is July 20, 2023. As of September 30, 2015 and December 31, 2014, $4.2 million and $4.3 million, respectively, was outstanding on the note.

Hedging Activities

Our results of operations are significantly affected by fluctuations in commodity prices and we seek to reduce our exposure to price volatility by hedging our production through swaps, options and other commodity derivative instruments. We have entered into commodity swaps on approximately 51% of our estimated oil production from our net proved developed producing reserves (based on reserve estimates as of June 30, 2015) through December 31, 2015, 74% for 2016, and 24% for 2017.

By removing a portion of price volatility on our future oil and gas production, we believe that we will mitigate, but not eliminate, the potential effects of changing commodity prices on our cash flow from operations. However, when prevailing market prices are higher than our contract prices, we will not realize increased cash flow on the portion of the production that has been hedged. We have sustained, and in the future will sustain, realized and unrealized losses on our derivative contracts when market prices are higher than our contract prices. Conversely, when prevailing market prices are lower than our contract prices, we will sustain realized and unrealized gains on our commodity derivative contracts.

If the disparity between our contract prices and market prices continues, we will sustain realized and unrealized gains or losses on our derivative contracts. While unrealized gains and losses do not impact our cash flow from operations, realized gains and losses do impact our cash flow from operations. In addition, as our derivative contracts expire over time, we expect to enter into new derivative contracts at then-current market prices. If the prices at which we hedge future production are significantly lower than our existing derivative contracts, our future cash flow from operations would likely be materially lower. In addition, borrowings under our credit facility bear interest at floating rates. If interest expense increases as a result of higher interest rates or increased borrowings, more cash flow from operations would be used to meet debt service requirements. As a result, we would need to increase our cash flow from operations in order to fund the development of our drilling opportunities which, in turn, will be dependent upon the level of our production volumes and commodity prices.

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

Net Operating Loss Carryforwards

At December 31, 2014, we had $150.8 million of net operating loss carryforwards for tax purposes. The loss carryforward will expire through 2034, if not utilized.

Uncertainties exist as to the future utilization of the operating loss carryforwards under the criteria set forth under ASC 740-10 Income Taxes. Therefore, we have established a valuation allowance of $60.1 million for deferred tax assets at December 31, 2014.

Table of Contents

Item 3. Quantitative and Qualitative Disclosures about Market Risk.

Commodity Price Risk

As an independent oil and gas producer, our revenue, cash flow from operations, other income and profitability, reserve values, access to capital and future rate of growth are substantially dependent upon the prevailing prices of oil and gas. Declines in commodity prices will adversely affect our financial condition, liquidity, ability to obtain financing and operating results. Lower commodity prices may reduce the amount of oil and gas that we can produce economically. Prevailing prices for such commodities are subject to wide fluctuation in response to relatively minor changes in supply and demand and a variety of additional factors beyond our control, such as global, political and economic conditions. Historically, prices received for our oil and gas production have been volatile and unpredictable, and such volatility is expected to continue. Most of our production is sold at market prices. Generally, if the commodity indexes fall, the price that we receive for our production will also decline. Therefore, the amount of revenue that we realize is partially determined by factors beyond our control. Assuming the production levels we attained during the nine months ended September 30, 2015, a 10% decline in oil and gas prices would have reduced our operating revenue, cash flow and net income by approximately $5.4 million. If commodity prices remain at their current levels the impact on operating revenues and cash flow, could be much more significant. However, we do have derivative contracts in place that will mitigate the impact of low commodity prices.

Derivative Instrument Sensitivity

We account for our derivative contracts in accordance with ASC 815. The derivative instruments we utilize are based on index prices that may and often do differ from the actual oil and gas prices realized in our operations. Management has elected not to apply 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.

For the nine months ended September 30, 2015, we recognized a realized gain of $6.9 million and an unrealized gain of $6.2 million on our commodity derivative contracts.

Interest Rate Risk

We are subject to interest rate risk associated with borrowings under our credit facility. As of September 30, 2015, we had $120.0 million of outstanding indebtedness under our credit facility. 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) 0.75%—1.75%%, depending on the utilization of the borrowing base, or, if we elect, LIBOR plus 1.75%—2.75%, depending on the utilization of the borrowing base. At September 30, 2015, the interest rate on the credit facility was 2.45%. For every percentage point that the LIBOR rate rises, our interest expense would increase by approximately $1.2 million on an annual basis, based on our outstanding indebtedness as of September 30, 2015.

Item 4. Controls and Procedures.

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

There were no changes in our internal controls over financial reporting during the nine months ended September 30, 2015 covered by this report that could materially affect, or are reasonably likely to materially affect, our financial reporting.

Table of Contents

PART II

Item 1. Legal Proceedings.

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, 2015, the Company was not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse impact on its financial position or results of operations.

Item 1A. Risk Factors.

In addition to the other information set forth in this report, you should carefully consider 4he factors discussed in Part I, "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2014, which could materially affect our business, financial condition or future results. The risks described in our Annual Report on Form 10-K are not the only risks facing Abraxas. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition and/or operating results.

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

None

Item 3. Defaults Upon Senior Securities.

None

Item 4. Mine Safety Disclosure.

Not applicable

Item 5. Other Information.

None

Item 6. Exhibits.

(a) Exhibits

Exhibit 31.1	Certification - Robert L.G. Watson, CEO
Exhibit 31.2	Certification - Geoffrey R. King, CFO
Exhibit 32.1	Certification pursuant to 18 U.S.C. Section 1350 - Robert L.G. Watson, CEO
Exhibit 32.2	Certification pursuant to 18 U.S.C. Section 1350 - Geoffrey R. King, CFO

Table of Contents

ABRAXAS PETROLEUM CORPORATION

SIGNATURES

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

Date	November 6, 2015	By: /s/Robert L.G. Watson ROBERT L.G. WATSON, President and Principal Executive Officer
Date	November 6, 2015	By: /s/Geoffrey R. King GEOFFREY R. KING, Vice President and Principal Financial Officer
Date	November 6, 2015	By: /s/G. William Krog, Jr. G. WILLIAM KROG, JR., Principal Accounting Officer