ABRAXAS PETROLEUM CORP
Form 10-Q
August 08, 2014

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 JUNE 30, 2014
o	TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934 FOR THE TRANSITION PERIOD FROM ______ TO ______

COMMISSION FILE NUMBER: 001-16071

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

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

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to the filing requirements for the past 90 days.   Yes 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 August 6, 2014 was 105,384,703.

1

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 availability of capital;
- the prices we receive for our production and the effectiveness of our hedging activities;
- 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.

“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

“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/text-idx?c=ecfr&rgn=div5&view=text&node=17:2.0.1.1.8&idno=17.

ABRAXAS PETROLEUM CORPORATION
FORM 10 – Q
INDEX

PART I
FINANCIAL INFORMATION

PART II
OTHER INFORMATION

PART I
FINANCIAL INFORMATION

Item 1. Financial Statements

Abraxas Petroleum Corporation
Condensed Consolidated Balance Sheets
(in thousands)

	June 30, 2014 (Unaudited)	December 31, 2013
Assets		
Current assets:		
Cash and cash equivalents	$3,742	$5,205
Accounts receivable, net:		
Joint owners	5,299	15,493
Oil and gas production	22,572	16,625
Other	980	1,497
	28,851	33,615
Derivative asset – current	113	85
Other current assets	362	644
Total current assets	33,068	39,549
Property and equipment:		
Oil and gas properties, full cost method of accounting:		
Proved	652,158	564,755
Other property and equipment	39,213	38,959
Total	691,371	603,714
Less accumulated depreciation, depletion, and amortization	(440,322)	(423,069)
Total property and equipment – net	251,049	180,645
Deferred financing fees, net	2,366	2,140
Derivative asset – long-term	—	925
Other assets	391	391
Total assets	$286,874	$223,650

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

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

	June 30, 2014 (Unaudited)	December 31, 2013
Liabilities and Stockholders' Equity		
Current liabilities:		
Accounts payable	$49,003	$52,793
Oil and gas production payable	16,509	23,810
Accrued interest	79	31
Other accrued expenses	2,106	1,231
Derivative liability – current	6,318	2,728
Current maturities of long-term debt	2,181	2,142
Total current liabilities	76,196	82,735
Long-term debt, excluding current maturities	44,850	41,790
Other liabilities	57	57
Derivative liability – long-term	5,785	2,274
Future site restoration	9,747	9,888
Total liabilities	136,635	136,744
Commitments and contingencies (Note 9)		
Stockholders' Equity		
Preferred stock, par value $0.01 per share, authorized 1,000,000 shares; -0- issued and outstanding	—	—
Common stock, par value $0.01 per share, authorized 200,000,000 shares; 105,346,011 and 92,906,049 issued and outstanding, respectively	1,053	929
Additional paid-in capital	308,696	253,193
Accumulated deficit	(158,871)	(166,609)
Accumulated other comprehensive loss	(639)	(607)
Total stockholders' equity	150,239	86,906
Total liabilities and stockholders' equity	$286,874	$223,650

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 June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Revenue:				
Oil and gas production revenues	$33,548	$21,478	$59,398	$42,641
Other	11	16	54	49
	33,559	21,494	59,452	42,690
Operating costs and expenses:				
Lease operating expenses	5,772	6,166	11,664	12,628
Production taxes	2,838	1,911	5,042	3,838
Depreciation, depletion, and amortization	9,242	5,776	16,877	12,285
Impairment	—	1,977	—	1,977
General and administrative (including stock-based compensation of $1,029, $669, $1,468 and $1,142, respectively)	3,117	2,797	5,940	5,327
	20,969	18,627	39,523	36,055
Operating income	12,590	2,867	19,929	6,635
Other (income) expense:				
Interest income	(1)	—	(1)	(1)
Interest expense	783	1,259	1,391	2,467
Amortization of deferred financing fees	280	343	629	676
Loss on derivative contracts - Realized	1,356	783	2,090	1,708
Loss (gain) on derivative contracts - Unrealized	7,136	(7,485)	8,080	(6,864)
Other	2	14	2	101
	9,556	(5,086)	12,191	(1,913)
Net income before income tax	3,034	7,953	7,738	8,548
Income tax expense	—	87	—	87
Net income	$3,034	$7,866	$7,738	$8,461
Net income per common share – basic	$0.03	$0.09	$0.08	$0.09
Net income per common share – diluted	$0.03	$0.08	$0.08	$0.09
Weighted average shares outstanding:				
Basic	93,448	92,351	93,009	92,323
Diluted	97,322	93,361	95,844	93,311

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

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Consolidated net income	$3,034	$7,866	$7,738	$8,461
Other comprehensive income (loss):				
Change in unrealized value of investments	—	56	—	49
Foreign currency translation adjustment	30	(266)	(32)	(397)
Other comprehensive income (loss)	30	(210)	(32)	(348)
Comprehensive income	$3,064	$7,656	$7,706	$8,113

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

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

	Six Months Ended June 30, 2014	2013
Operating Activities		
Net income	$7,738	$8,461
Adjustments to reconcile net income to net cash provided by (used in) operating activities:		
Change in derivative fair value	7,998	(6,840)
Depreciation, depletion, and amortization	16,877	12,285
Impairment	—	1,977
Amortization of deferred financing fees	629	676
Accretion of future site restoration	290	335
Stock-based compensation	1,468	1,142
Changes in operating assets and liabilities:		
Accounts receivable	4,766	(6,474)
Other	281	4,941
Accounts payable and accrued expenses	(10,594)	6,268
Net cash provided by operating activities	29,453	22,771
Investing Activities		
Capital expenditures, including purchases and development of properties	(92,770)	(33,466)
Proceeds from sale of oil and gas properties	5,471	3,192
Net cash used in investing activities	(87,299)	(30,274)
Financing Activities		
Proceeds from long-term borrowings	48,000	21,000
Payments on long-term borrowings	(44,901)	(13,101)
Proceeds from issuance of common stock	53,958	—
Deferred financing fees	(855)	(96)
Exercise of stock options	201	44
Other	(26)	(29)
Net cash provided by financing activities	56,377	7,818
Effect of exchange rate changes on cash	6	56
(Decrease) increase in cash	(1,463)	371
Cash and equivalents, at beginning of period	$5,205	2,061
Cash and equivalents, at end of period	$3,742	$2,432
Supplemental disclosure of cash flow information:		
Interest paid	$1,052	$2,256

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

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

Note 1. Basis of Presentation

The accounting policies followed by Abraxas Petroleum Corporation and its subsidiaries (the “Company”) are set forth in the notes to the Company’s audited consolidated financial statements in the Annual Report on Form 10-K for the year ended December 31, 2013 filed with the SEC on March 17, 2014. 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 June 30, 2014 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, 2013.

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”) and a wholly-owned foreign subsidiary, Canadian Abraxas Petroleum, ULC (“Canadian Abraxas”).

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

Rig Accounting

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

Use of Estimates

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

New Accounting Standards and Disclosures

Revenue Recognition

The Financial Accounting Standards Board ("FASB") issued an Accounting Standards Update ("ASU") in May 2014 which provides accounting guidance for all revenue arising from contracts to provide goods or services to customers. The requirements from the new ASU are effective for interim and annual periods beginning after December 15, 2016, and early adoption is not permitted. The standard allows for either full retrospective adoption or modified retrospective adoption. At this time, we are evaluating the guidance to determine the method of adoption and the impact of this ASU on our financial statements and related disclosures, if any.

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 June 30,		Six Months Ended June 30,	
2014	2013	2014	2013
$807	$558	$1,114	$920

The following table summarizes the Company's stock option activity for the six months ended June 30, 2014:

	Number of Shares	Weighted Average Option Exercise Price Per Share	Weighted Average Grant Date Fair Value Per Share
Outstanding, December 31, 2013	5,400	$2.77	$1.98
Granted	1,020	$3.36	$2.43
Exercised	(351)	$2.69	$1.86
Canceled	(67)	$2.97	$2.11
Outstanding, June 30, 2014	6,002	$2.87	$2.06

Additional information related to stock options at June 30, 2014 and December 31, 2013 is as follows:

	June 30, 2014	December 31, 2013
Options exercisable	4,069	3,828

As of June 30, 2014, there was approximately $3.3 million of unamortized compensation expense related to outstanding stock options that will be recognized in 2014 through 2017.

Restricted Stock Awards

Restricted stock awards are awards of common stock that are subject to restrictions on transfer and to a risk of forfeiture if the awardee terminates employment with the Company prior to the lapse of the restrictions. The fair value of such stock was determined using the closing price on the grant date and compensation expense is recorded over the applicable vesting periods.

The following table summarizes the Company's restricted stock activity for the six months ended June 30, 2014:

	Number of Shares	Weighted Average Grant Date Fair Value Per Share
Unvested, December 31, 2013	355	$3.24
Granted	762	3.15
Vested/Released	(5)	2.94
Forfeited	(20)	3.47
Unvested, June 30, 2014	1,092	$3.18

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

Three Months Ended June 30,		Six Months Ended June 30,	
2014	2013	2014	2013
$222	$111	$354	$222

As of June 30, 2014, there was approximately $2.5 million of unamortized compensation expense relating to outstanding restricted shares that will be recognized in 2014 through 2017.

Common Stock Offering

On June 24, 2014, we completed a public offering of 11.5 million common shares at $5.00 per share. The offering was made pursuant to an effective shelf registration statement on Form S-3 previously filed by the Company with the SEC. We received proceeds of approximately $54.0 million after deducting discounts and offering costs. The proceeds from this offering were used to repay indebtedness under our credit facility.

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 June 30, 2013, our net capitalized costs of oil and gas properties in the United States did not exceed the cost ceiling of our estimated proved reserves; however, the net capitalized cost of oil and gas properties in Canada exceeded the cost ceiling by $2.0 million resulting in a write down for the six months ended June 30, 2013. At June 30, 2014, our net capitalized costs of oil and gas properties in the United States and Canada did not exceed the cost ceiling of our estimated proved reserves.

Restoration, Removal and Environmental Liabilities

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

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

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

The following table summarizes the Company’s asset retirement obligation transactions for the six months ended June 30, 2014 and the year ended December 31, 2013:

	June 30, 2014	December 31, 2013
Beginning asset retirement obligation	$9,888	$11,381
New wells placed on production and other	151	222
Deletions related to property disposals and plugging costs	(437)	(2,491)
Accretion expense	290	638
Revisions and other	(145)	138
Ending asset retirement obligation	$9,747	$9,888

Note 2. Income Taxes

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

For the three and six months ended June 30, 2014, 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 June 30, 2014, the Company did not have any accrued interest or penalties related to uncertain tax positions. The tax years 2003 through 2013 remain open to examination by the tax jurisdictions to which the Company is subject.

At December 31, 2013, the Company had, subject to the limitation discussed below, $141.9 million of net operating loss carryforwards for U.S. tax purposes and $21.8 million of net operating loss carryforwards for Canadian tax purposes. The U.S. loss carryforward will expire in varying amounts through 2032 and the Canadian loss carryforward will expire in 2033, 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 $75.6 million for deferred tax assets at December 31, 2013.

Note 3. Long-Term Debt

14

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

	June 30, 2014	December 31, 2013
Credit facility	$37,000	$33,000
Rig loan agreement	5,586	6,378
Real estate lien note	4,445	4,554
	47,031	43,932
Less current maturities	(2,181)	(2,142)
	$44,850	$41,790

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 June 30, 2014, $37.0 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. As of June 30, 2014 we had a borrowing base of $162.5 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 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 of $162.5 million was determined based upon our reserve report dated December 31, 2013. 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 June 30, 2014 the interest rate on the credit facility was 1.9% based on 1-month LIBOR borrowings and the 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 debt to EBITDAX ratio as of the last day of each quarter of not more than 4.00 to 1.00. The current ratio is defined as the ratio of consolidated current assets to consolidated current liabilities. For the purposes of this calculation, current assets include the portion of the borrowing base which is undrawn but excludes any cash deposited with 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 June 30, 2014, we were in compliance with all of our debt covenants. As of June 30, 2014, the interest coverage ratio was 20.66 to 1.00, the total debt to EBITDAX ratio was 0.62 to 1.00 and our current ratio was 2.34 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 with RBS Asset Finance, Inc. to finance the costs of purchasing and refurbishing an Oilwell 2,000 hp diesel electric drilling rig (the "Collateral"). The rig loan agreement provided for interim borrowings payable to Raven Drilling until the final amount of the loan was determined.

On February 14, 2012, Raven Drilling finalized the note with respect to the rig loan agreement. The principal amount of the note is $7.0 million and bears interest at 4.26%. Interest only is due for the first 18-months of the note and thereafter, the note will amortize in full over the remaining life of the note. Interest and principal, when required, is payable monthly. Subject to earlier prepayment provisions and events of default, the stated maturity date of the note is February 14, 2017. As of June 30, 2014, $5.6 million was outstanding under the rig loan agreement.

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

Real Estate Lien Note

On May 9, 2008, the Company entered into an advancing line of credit in the amount of $5.4 million for the purchase and finish out of a building to serve as its corporate headquarters. This note was refinanced in November 2008. The note was modified on April 4, 2013, reducing the interest to a fixed rate of 4.25%, and was further modified on July 20, 2013 to extend the maturity date to July 20, 2023. The note is payable in monthly installments of principal and interest of $34,354 based on a twenty year amortization. Beginning August 20, 2018, the interest rate will adjust to the bank's current prime rate plus 1.00% with a maximum annual rate of 7.25% The note is secured by a first lien deed of trust on the property and improvements. As of June 30, 2014, $4.4 million was outstanding on the note.

Note 4. Income Per Share

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Numerator:				
Net income	$3,034	$7,866	$7,738	$8,461
Denominator:				
Denominator for basic income per share - Weighted-average shares	93,448	92,351	93,009	92,323
Effect of dilutive securities:				
Stock options and restricted stock	3,874	1,010	2,835	988
Denominator for diluted income per share - Weighted-average shares and assumed conversions	97,322	93,361	95,844	93,311
Net income per common share – basic	$0.03	$0.09	$0.08	$0.09
Net income per common share – diluted	$0.03	$0.08	$0.08	$0.09

Note 5. Hedging Program and Derivatives

The derivative instruments we utilize are based on index prices that may and often do differ from the actual oil and gas prices realized in our operations. Management has elected not to apply hedge accounting as prescribed by ASC 815. Accordingly, fluctuations in the market value of the derivative contracts are recognized in earnings during the current period.

The following table sets forth our derivative contracts at June 30, 2014:

Contract Periods	Fixed Price Swap Oil – WTI Daily Volume (Bbl)	Swap Price (per Bbl)	Oil - Brent Daily Volume (Bbl)	Swap Price (per Bbl)	Oil - LLS Daily Volume (Bbl)	Swap Price (per Bbl)	Gas Daily Volume (Mcf)	Swap Price (per Mcf)
2014	1,535	$91.87	—	$—	98	$101.26	3,150	$4.07
2015	921	$85.00	125	$96.78	—	$—	1,450	$4.08
2016	948	$84.10	—	$—	—	$—	—	$—
2017	493	$84.18	—	$—	—	$—	—	$—

At June 30, 2014, the aggregate fair value of our commodity derivative contracts was a liability of approximately $12.0 million.

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

Fair Value of Derivative Instruments as of June 30, 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	$113	Derivatives – current	$6,318
Commodity price derivatives	Derivatives - long-term	—	Derivatives - long-term	5,785
		$113		$12,103

Fair Value of Derivative Instruments as of December 31, 2013

	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	$85	Derivatives – current	$2,728
Commodity price derivatives	Derivatives – long-term	925	Derivatives – long-term	2,274
		$1,010		$5,002

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

Note 6. Fair Value

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

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

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

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

A financial instrument’s categorization within the valuation hierarchy is based upon the lowest level of input that is significant to the fair value measurement. The Company’s assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. The Company is further required to assess the creditworthiness of the counter-party to the derivative contract. The results of the assessment of non-performance risk, based on the counter-party’s credit risk, could result in an adjustment of the carrying value of the derivative instrument. The following tables set forth information about the Company’s assets and liabilities measured at fair value on a recurring basis as of June 30, 2014 and December 31, 2013, and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair value (in thousands):

	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Balance as of June 30, 2014
Assets:				
NYMEX Fixed Price Derivative contracts	$—	$113	$—	$113
Total Assets	$—	$113	$—	$113
Liabilities:				
NYMEX Fixed Price Derivative contracts	$—	$12,103	$—	$12,103
Total Liabilities	$—	$12,103	$—	$12,103

18

	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, 2013
Assets:				
NYMEX Fixed Price Derivative contracts	$—	$1,010	$—	$1,010
Total Assets	$—	$1,010	$—	$1,010
Liabilities:				
NYMEX Fixed Price Derivative contracts	$—	$5,002	$—	$5,002
Total Liabilities	$—	$5,002	$—	$5,002

The Company’s derivative contracts consist of NYMEX-based fixed price commodity swaps and Brent-based fixed price commodity swaps. The NYMEX-based and Brent based fixed price derivative contracts are indexed to their respective futures contracts, which are actively traded for the underlying commodity and commonly used in the energy industry. 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.

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.

Note 7. Business Segments

The following tables provide the Company’s geographic operating segment data for the three and six months ended June 30, 2014 and 2013:

	Three Months Ended June 30, 2014			
	U.S.	Canada	Corporate	Total
Revenues:				
Oil and gas production	$33,181	$367	$—	$33,548
Other	—	—	11	11
	33,181	367	11	33,559
Expenses:				
Lease operating	5,585	187	—	5,772
Production taxes	2,838	—	—	2,838
Depreciation, depletion and amortization	9,044	136	62	9,242
General and administrative	508	56	2,553	3,117
Net interest	140	6	636	782
Amortization of deferred financing fees	—	—	280	280
Loss on derivative contracts - Realized	—	—	1,356	1,356
Loss on derivative contracts - Unrealized	—	—	7,136	7,136
Other	—	—	2	2
Net income (loss)	$15,066	$(18)	$(12,014)	$3,034

	Three Months Ended June 30, 2013			
	U.S.	Canada	Corporate	Total
Revenues:				
Oil and gas production	$20,946	$532	$—	$21,478
Other	—	—	16	16
	20,946	532	16	21,494
Expenses (income):				
Lease operating	5,783	383	—	6,166
Production taxes	1,906	5	—	1,911
Depreciation, depletion and amortization	5,411	302	63	5,776
Impairment	—	1,977	—	1,977
General and administrative	486	186	2,125	2,797
Net interest	157	5	1,097	1,259
Amortization of deferred financing fees	—	—	343	343
Loss on derivative contracts - Realized	—	—	783	783
(Gain) on derivative contracts - Unrealized	—	—	(7,485)	(7,485)
Other	—	—	14	14
Income tax expense	—	—	87	87
Net income (loss)	$7,203	$(2,326)	$2,989	$7,866

	Six Months Ended June 30, 2014			
	U.S.	Canada	Corporate	Total
Revenues:				
Oil and gas production	$58,656	$742	$—	$59,398
Other	—	—	54	54
	58,656	742	54	59,452
Expenses:				
Lease operating	11,230	434	—	11,664
Production taxes	5,042	—	—	5,042
Depreciation, depletion and amortization	16,481	272	124	16,877
General and administrative	1,017	404	4,519	5,940
Net interest	278	12	1,100	1,390
Amortization of deferred financing fees	—	—	629	629
Loss on derivative contracts - Realized	—	—	2,090	2,090
Loss on derivative contracts - Unrealized	—	—	8,080	8,080
Other	—	—	2	2
Net income (loss)	$24,608	$(380)	$(16,490)	$7,738

	Six Months Ended June 30, 2013			
	U.S.	Canada	Corporate	Total
Revenues:				
Oil and gas production	$41,504	$1,137	$—	$42,641
Other	—	—	49	49
	41,504	1,137	49	42,690
Expenses:				
Lease operating	11,587	1,041	—	12,628
Production taxes	3,833	5	—	3,838
Depreciation, depletion and amortization	11,625	535	125	12,285
Impairment	—	1,977	—	1,977
General and administrative	961	341	4,025	5,327
Net interest	323	11	2,132	2,466
Amortization of deferred financing fees	—	—	676	676
Loss on derivative contracts - Realized	—	—	1,708	1,708
(Gain) on derivative contracts - Unrealized	—	—	(6,864)	(6,864)
Other	—	—	101	101
Income tax expense	—	—	87	87
Net income (loss)	$13,175	$(2,773)	$(1,941)	$8,461

The following table provides the Company's geographic asset data as of June 30, 2014 and December 31, 2013:

Segment Assets:	June 30, 2014	December 31, 2013
United States	$277,407	$213,212
Canada	1,467	1,640
Corporate	8,000	8,798
	$286,874	$223,650

Note 8. Contingencies – Litigation

From time to time, the Company is involved in litigation relating to claims arising out of its operations in the normal course of business. At June 30, 2014, the Company was not engaged in any legal proceedings that are expected, individually or in the aggregate, to have a material adverse effect on its operations.

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, 2013 filed with the SEC on March 17, 2014.

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, 2013.

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

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

Commodity Prices and Hedging Activities

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

During the six months ended June 30, 2014, the New York Mercantile Exchange (NYMEX) future price for oil averaged $100.84 per barrel as compared to $94.26 per barrel during the six months ended June 30, 2013. NYMEX future spot prices for gas averaged $4.65 per MMBtu for the six months ended June 30, 2014 compared to $3.76 for the same period of 2013. Prices closed on June 30, 2014 at $105.37 per Bbl of oil and $4.46 per MMBtu of gas, compared to closing on June 30, 2013 at $96.56 per Bbl of oil and $3.57 per MMBtu of gas. The realized prices that we receive for our production differ from NYMEX futures and spot market prices, principally due to:

- basis differentials which are dependent on actual delivery location;
- adjustments for BTU content;
- quality of the hydrocarbons; and

- gathering; processing and transportation costs.

The following table sets forth our average differentials for the six months ended June 30, 2014 and 2013:

	Oil - NYMEX		Gas - NYMEX	
	2014	2013	2014	2013
Average realized price (1)	$92.57	$90.61	$4.69	$3.26
Average NYMEX price	$100.84	$94.26	$4.65	$3.76
Differential	$(8.27)	$(3.65)	$0.04	$(0.50)

(1) excludes the impact of derivative activities

Increases in the differential between the NYMEX price and the realized price we receive have in the past, and could in the future, significantly reduce our revenues and cash flow from operations. The decrease in the gas differential was primarily due to gas produced in the Bakken which had a lower differential due to the quality of the gas. The increase in the oil differential was due to oil produced in the Bakken which carries a higher differential.

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. By removing a significant portion of price volatility on our future production, we believe we will mitigate, but not eliminate, the potential effects of changing commodity prices on our cash flow from operations for those periods. However, when prevailing market prices are higher than our contract prices, we will not realize increased cash flow on the portion of the production that has been hedged. We have sustained and, in the future, will sustain realized and unrealized losses on our derivative contracts when market prices are higher than our contract prices. Conversely, when prevailing market prices are lower than our contract prices, we will recognize realized and unrealized gains on our commodity derivative contracts. In the six months ended June 30, 2014, we recognized a realized loss of $2.1 million and an unrealized loss of $8.1 million on our commodity swaps. In the six months ended June 30, 2013, we recognized a realized loss of $1.7 million and an unrealized gain of $6.9 million on our commodity swaps. We have not designated any of these derivative contracts as a hedge as prescribed by applicable accounting rules.

The following table sets forth our derivative contracts at June 30, 2014:

	Fixed Price Swap							
	Oil – WTI		Oil - Brent		Oil - LLS		Gas	
Contract Periods	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (Bbl)	Swap Price (per Bbl)	Daily Volume (Mcf)	Swap Price (per Mcf)
2014	1,535	$91.87	—	$—	98	$101.26	3,150	$4.07
2015	921	$85.00	125	$96.78	—	$—	1,450	$4.08
2016	948	$84.10	—	$—	—	$—	—	$—
2017	493	$84.18	—	$—	—	$—	—	$—

At June 30, 2014, the aggregate fair value of our oil and gas derivative contracts was a liability of approximately $12.0 million.

Production Volumes

Our proved reserves will decline as oil and gas are produced, unless we find, acquire or develop additional properties containing proved reserves or conduct successful exploration and development activities in a timely manner. Based on the reserve information set forth in our reserve estimates as of December 31, 2013, the average annual estimated decline rate for our net proved developed producing reserves is 9% during the first five years, 9% in the next five years, and approximately 9% thereafter. These rates of decline are estimates and actual production declines could be materially higher. While we have had some success in finding, acquiring and developing additional reserves, we have not always been able to fully replace the production volumes lost from natural field declines and prior property sales. Our ability to acquire or find additional reserves will be dependent, in part, upon the amount of available funds for acquisition, exploration and development projects.

We had capital expenditures of $92.8 million during the six months ended June 30, 2014. We have a capital expenditure budget for 2014 of $190.0 million. The majority of the 2014 budget will be spent on unconventional horizontal oil wells in the Williston Basin (Bakken/Three Forks) in the Rocky Mountain region and in the Eagle Ford shale play in South Texas. The 2014 capital expenditure budget is subject to change depending upon a number of factors, including the availability and costs of drilling and service equipment and crews, economic and industry conditions at the time of drilling, prevailing and anticipated prices for oil and gas, the availability of sufficient capital resources, the results of our exploitation efforts, and our ability to obtain permits for drilling locations.

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 the sale of debt or equity securities, although we may not be able to complete any financing on terms acceptable to us, if at all. As of June 30, 2014, we had $125.5 million of availability under our credit facility and $3.7 million of cash and cash equivalents.

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, 2013, we operated properties accounting for approximately 94% of our PV-10, giving us substantial control over the timing and incurrence of operating and capital expenditures. We have identified numerous additional drilling locations on our existing leaseholds, the successful development of which we believe could significantly increase our production and proved reserves. Over the five years ended December 31, 2013, we drilled or participated in 142 gross (40.0 net) wells of which 96% were commercially 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 56% of our estimated proved reserves at December 31, 2013 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

Eagle Ford

At Abraxas’ Jourdanton prospect in Atascosa County, Texas, the Company successfully completed the Ribeye 1H and Ribeye 2H with a combined 49 frac stages. After drill out, the wells will be placed on production and thirty day rates will be provided when available. Following the drilling of the Dutch 3H and Dutch 4H, Abraxas will mobilize the rig to the Cat Eye 1H, which represents the first well on the Company’s southern fault block. Abraxas owns a 100% working interest across the Jourdanton prospect.

At Abraxas' Cave prospect, in McMullen County, Texas, the Dutch 1H averaged 786 boepd (669 barrels of oil per day, 700 mcf of natural gas per day) [(1)] over the well's first 30 full days of production. The Company successfully mobilized the drilling rig to the Dutch 3H and Dutch 4H pad where it is currently drilling the Dutch 3H at 12,538 feet. Abraxas holds a 100% working interest in the Dutch 1H, 2H, 3H and 4H.

At Abraxas' Dilworth East prospect, in McMullen County, Texas the R. Henry 2H averaged 780 boepd (515 barrels of oil per day, 1,586 mcf of natural gas per day) [(1)] over the well's first 30 full days of production. Abraxas holds a 100% working interest in the R. Henry 2H.

Williston Basin

At Abraxas' North Fork prospect, in McKenzie County, North Dakota, the Company completed the Ravin 5H, 6H and 7H with a combined 99 frac stages. The Ravin 4H was completed with seven stages before encountering mechanical issues. As a precaution, the Company elected to pull the 4 ½ inch tie back string, polished bore receptacle and seal assembly before resuming the fracture stimulation of the well. It is anticipated the Company will resume the completion of the Ravin 4H and turn the well to sales by late September. The Ravin 5H, 6H and 7H, which will test 660 foot spacing in the Middle Bakken, are expected to begin flowback shortly. Abraxas recently set surface casing on the Stenehjem 2H, 3H and 4H. The Company also set intermediate casing on the Stenehjem 4H and is currently drilling the intermediate section of the Stenehjem 3H at 10,243 feet. The three wellbores will be 660 feet apart in their respective formations. Abraxas owns a working interest of approximately 51% and 73% in the Ravin West and Stenehjem wells, respectively.

Results of Operations

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2014	2013	2014	2013
Operating revenue: (1)				
Oil sales	$29,514	$17,261	$50,450	$34,445
Gas sales	2,752	3,137	6,002	5,989
NGL sales	1,282	1,080	2,946	2,207
Other	11	16	54	49
	$33,559	$21,494	$59,452	$42,690
Operating income	12,590	2,867	19,929	6,635
Oil sales (MBbl)	313	191	545	380
Gas sales (MMcf)	633	894	1,279	1,839
NGL sales (MBbl)	35	34	73	67
BOE sales	454	374	831	753
Average oil sales price (per Bbl) (1)	$94.34	$90.59	$92.57	$90.61
Average gas sales price (per Mcf) (1)	$4.35	$3.51	$4.69	$3.26
Average NGL sales price (per Bbl)	$36.16	$31.46	$40.61	$33.12
Average oil equivalent price (Boe)	$73.93	$57.45	$71.50	$56.60

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

Comparison of Three Months Ended June 30, 2014 to Three Months Ended June 30, 2013

Operating Revenue. During the three months ended June 30, 2014, operating revenue increased to $33.6 million from $21.5 million for the same period of 2013. The increase in revenue was primarily due to higher oil sales and an increase in realized commodity prices. Oil sales volume increased by 64% contributing $11.5 million to revenue for the quarter ended June 30, 2014. Lower gas sales volumes negatively impacted revenue by $1.1 million. Higher commodity prices contributed $1.6 million to revenue for the three months ended June 30, 2014.

Oil sales volumes increased to 313 MBbl during the quarter ended June 30, 2014 from 191 MBbl for the same period of 2013. The increase in oil sales was due to new wells brought on line offset by natural field declines and property sales. New wells brought on production contributed 211 MBbl for the three months ended June 30, 2014. Wells sold contributed 84 MBbls for the quarter ended June 30, 2013 as compared to 0.3 MBbls in the same period of 2014. Gas sales volumes decreased to 633 MMcf for the three months ended June 30, 2014 from 894 MMcf for the same period of 2013. The decrease in gas sales was due to natural field declines and property sales partially offset by new wells brought on line. New wells brought on line produced 69 MMcf for the three months ended June 30, 2014. Sold wells contributed 105 MMcf for the second quarter of 2013 as compared to 0.2 MMcf in 2014. NGL sales volumes increased slightly to 35 MBbl for the three months ended June 30, 2014 from 34 MBbl for the same period of 2013. The increase in NGL sales was primarily due to production in West Texas, North Dakota and in the Eagle Ford that has a higher NGL content than our historical gas production.

Lease Operating Expenses (“LOE”). LOE for the three months ended June 30, 2014 decreased to $5.8 million from $6.2 million for the same period of 2013. LOE per Boe for the three months ended June 30, 2014 was $12.72 compared to $16.49 for the same period of 2013. The decrease in LOE was primarily due to significant non-recurring LOE and the sale of high cost properties during 2013. The decrease per Boe was due to higher sales volumes as well as lower overall costs for the three months ended June 30, 2014 as compared to the same period of 2013.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the three months ended June 30, 2014 increased to $2.8 million from $1.9 million for the same period of 2013, primarily as the result of higher sales volumes and higher realized prices.

General and Administrative (“G&A”) Expenses. G&A expenses, excluding stock-based compensation, were $2.1 million for the quarters ended June 30, 2014 and 2013. G&A per Boe was $4.60 for the quarter ended June 30, 2014 compared to $5.69 for the same period of 2013. The decrease per Boe was due to higher sales volumes for the three months ended June 30, 2014 as compared to the same period of 2013.

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 June 30, 2014, stock based compensation was $1.0 million as compared to $0.7 million for the same period of 2013. The increase was primarily due to the grant of restricted stock and options in March of 2014.

Depreciation, Depletion and Amortization (“DD&A”) Expenses. DD&A expense for the three months ended June 30, 2014 increased to $9.2 million from $5.8 million for the same period of 2013. The increase was primarily the result of an increase in future development costs in our December 31, 2013 reserve report and a significant increase in sales volumes in the second quarter of 2014 as compared to the second quarter of 2013. DD&A expense per Boe for the three months ended June 30, 2014 was $20.36 compared to $15.45 in 2013. The increase in per Boe DD&A was due to a higher depletion base in 2014 as compared to 2013 as a result of higher future development costs.

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 June 30, 2014, the net capitalized cost of our oil and gas properties in the United Stated and Canada did not exceed the present value of our estimated proved reserves. As of June 30, 2013, our net capitalized costs of oil and gas properties in the United States did not exceed the present value of our estimated proved reserves, however the net capitalized cost of our oil and gas properties in Canada exceeded the present value of our estimated proved reserves by $2.0 million, resulting in a write down of $2.0 million in 2013.

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 June 30, 2014 was $0.8 million as compared to $1.3 million for the same period of 2013. The decrease in interest expense was due to lower levels of debt for the three months ended June 30, 2014, as well as lower interest rates.

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. The net estimated value of our commodity derivative contracts was a liability of of approximately $12.0 million as of June 30, 2014. 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 June 30, 2014, we incurred a realized a loss on our derivative contracts of $1.4 million and an unrealized loss of $7.1 million. For the three months ended June 30, 2013, we realized a loss on our commodity derivative contracts of $0.8 million and incurred an unrealized gain of $7.5 million on our commodity derivative contracts.

Income Tax Expense. Income tax expense for the period ended June 30, 2013 is related to income taxes assessed as a result of an Internal Revenue Service examination of our 2009 Federal income tax return as well as various state taxes. On July 23, 2013, we settled the assessment resulting in $81,000 being recognized as federal income tax expense for the quarter ended June 30, 2013. We did not incur any income tax expense for the quarter ended June 30, 2014 as a result of the application of our operating loss carryforwards.

Comparison of Six Months Ended June 30, 2014 to Six Months Ended June 30, 2013

Operating Revenue. During the six months ended June 30, 2014, operating revenue increased to $59.5 from $42.7 million for the same period of 2013. The increase in revenue was primarily due to higher sales volumes of oil and NGL, which was offset by lower gas sales volumes. Increased sales volumes of oil and NGLs contributed $15.5 million to operating revenues, while lower gas sales volumes had a negative impact of $2.6 million. Increased commodity prices contributed $3.9 million to revenue for the six months ended June 30, 2014.

Oil sales volumes increased 43% to 545 MBbl during the six months ended June 30, 2014 from 380 MBbl for the same period of 2013. The increase in oil sales was due to new wells being brought on line offset by natural field declines and property sales. New wells contributed 344 MBbl for the six months ended June 30, 2014. Sold wells contributed 141 MBbls for the six months ended June 30, 2013 as compared to 2.4 MMbls for the same period of 2014. Gas sales volumes decreased to 1,279 MMcf for the six months ended June 30, 2014 from 1,839 MMcf for the same period of 2013. The decrease in gas sales was due to natural field declines and property sales partially offset by new wells brought on line. New wells brought onto production contributed 145 MMcf for the six months ended June 30, 2014. Sold wells contributed 223 MMcf during the first six months of 2013 compared to 19 MMcf for the same period of 2014. NGL sales volumes increased to 73 MBbl for the six months ended June 30, 2014 from 67 MBbl for the same period of 2013. The increase in NGL sales was primarily due to gas production in West Texas, North Dakota and Eagle Ford that has a higher NGL content than our 2013 gas production.

LOE. LOE for the six months ended June 30, 2014 decreased to $11.7 million from $12.6 million for the same period of 2013. The decrease in 2014 was due to significant non-recurring LOE as well as the sale of high cost properties during 2013. LOE per Boe for the six months ended June 30, 2014 was $14.04 compared to $16.76 for the same period of 2013. The decrease per Boe was due to lower costs and higher sales volumes for the six months ended June 30, 2014 as compared to the same period of 2013.

Production and Ad Valorem Taxes. Production and ad valorem taxes for the six months ended June 30, 2014 increased to $5.0 million from $3.8 million for the same period of 2013. The increase was primarily the result of higher oil sales volumes and higher realized commodity prices for the six months ended June 30, 2014 as compared to the same period of 2013.

G&A Expenses. G&A expenses, excluding stock-based compensation, increased to $4.5 million for the first six months of 2014 from $4.2 million for the same period of 2013. The increase in G&A expense was primarily related to an increase in overall salaries offset by lower professional fees. Professional fees were higher in 2013 due to a proxy contest. G&A expense per Boe was $5.38 for the six months ended June 30, 2014 compared to $5.56 for the same period of 2013. The decrease per Boe was primarily due to higher sales volumes in the first six months of 2014 compared to the same period in 2013.

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 six months ended June 30, 2014 stock based compensation was $1.5 million as compared to $1.1 million for the same period of 2013. The increase was primarily due to restricted stock and option grants in March 2014.

DD&A Expenses. DD&A expense for the six months ended June 30, 2014 increased to $16.9 million from $12.3 million for same period of 2013. The increase was primarily the result of increased production volumes, as well as an increase in the depletion base in 2014 as compared to 2013. The increase in the depletion base was due to higher future development cost in our December 31, 2013 reserve report. Our DD&A expense per Boe for the six months ended June 30, 2014 was $20.31 compared to $16.31 in 2013.

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 June 30, 2014, our net capitalized costs of oil and gas properties in the United States and Canada did not exceed the present value of our estimated proved reserves. As of June 30, 2013 the net capitalized cost of our oil and gas properties in Canada exceeded the present value of our estimated proved reserves by $2.0 million, resulting in a write down of $2.0 million.

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 six months ended June 30, 2014 was $1.4 million as compared to $2.5 million for the same period of 2013. The decrease in 2014 was due to lower levels of debt and lower interest rates as compared to the same period of 2013.

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. The net estimated value of our commodity derivative contracts was a liability of approximately $12.0 million as of June 30, 2014. 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 six months ended June 30, 2014, we realized a loss on our commodity derivative contracts of $2.1million and an unrealized loss of $8.1 million. For the six months ended June 30, 2013, we realized a loss on our commodity derivative contracts of $1.7 million and recognized an unrealized gain of $6.9 million.

Income Tax Expense. Income tax expense for the period ended June 30, 2013 is related to income taxes assessed as a result of an Internal Revenue Service examination of our 2009 Federal income tax return as well as various state taxes. On July 23, 2013, we settled the assessment resulting in $81,000 being recognized as federal income tax expense for the six months ended June 30, 2013. No income tax was recognized for the six months ended June 30, 2014 as a result of the application of our operating loss carryforwards.

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 an opportunity presents itself, the sale of debt or equity securities, although we may not be able to complete any financings on terms acceptable to us, if at all.

Capital Expenditures. Capital expenditures during the six months ended June 30, 2014 were $92.8 million compared to $33.5 million during the same period of 2013.

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

	Six Months Ended June 30,	
	2014	2013
Expenditure category:		
Development	$91,323	$32,996
Facilities and other	1,447	470
Total	$92,770	$33,466

During the six months ended June 30, 2014 and June 30, 2013, capital expenditures were primarily for development of our existing oil and gas properties and the acquisition of leasehold in our core areas. We anticipate making capital expenditures in 2014 of $190.0 million. The 2014 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 also include expenditures for the acquisition of producing properties, and could increase if such opportunities arise. Additionally, the level of capital expenditures will vary during future periods depending on economic and industry conditions and commodity prices. Should the prices of oil and gas decline and if our costs of operations increase or if our production volumes decrease, our cash flows will decrease which may result in a reduction of the capital expenditure budget. If we decrease our capital expenditure budget, we may not be able to offset oil and gas production decreases caused by natural field declines.

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

	Six Months Ended June 30,	
	2014	2013
Net cash provided by operating activities	$29,453	$22,771
Net cash used in investing activities	(87,299)	(30,274)
Net cash provided by financing activities	56,377	7,818
Total	$(1,469)	$315

Operating activities during the six months ended June 30, 2014 provided $29.5 million of cash compared to providing $22.8 million in the same period of 2013. Net income plus non-cash expense items during the six months ended June 30, 2014 and 2013 and net changes in operating assets and liabilities accounted for most of these funds. Investing activities used $87.3 million during the six months ended June 30, 2014 compared to using $30.3 million for the same period of 2013. Funds used during the six months ended June 30, 2014 were primarily expenditures for the development of our existing properties and leasehold acquisitions. Funds used during the six months ended June 30, 2013 were primarily expenditures for the development of our existing properties. Financing activities provided $56.4 million for the six months ended June 30, 2014 compared to providing $7.8 million for the same period in 2013. Funds provided during the six months ended June 30, 2014 were primarily proceeds from a public offering of common stock offset by payments on our credit facility. Funds provided during the six months ended June 30, 2013 were primarily proceeds from borrowings under our credit facility.

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

Cash from operating activities is dependent upon commodity prices and production volumes. A decrease in commodity prices from current levels could reduce our cash flows from operations. This could cause us to alter our business plans, including reducing our exploration and development plans. Unless we otherwise expand and develop reserves, our production volumes may decline as reserves are produced. In the future we may continue to sell producing properties, which could further reduce our production volumes. To offset the loss in production volumes resulting from natural field declines and sales of producing properties, we must conduct successful exploration and development activities, acquire additional producing properties or identify and develop additional behind-pipe zones or secondary recovery reserves. We believe our numerous drilling opportunities will allow us to increase our production volumes; however, our drilling activities are subject to numerous risks, including the risk that no commercially productive oil and gas reservoirs will be found. If our proved reserves decline in the future, our production could also decline and, consequently, our cash flow from operations and the amount that we are able to borrow under our credit facility could also decline. The risk of not finding commercially productive reservoirs will be compounded by the fact that 56% of our total estimated proved reserves at December 31, 2013 were classified as undeveloped.

We have in the past, and may, in the future, sell producing properties. Beginning in the third quarter of 2012 and continuing through the second quarter of 2014, we have sold certain non-core assets for combined net proceeds of approximately $154.6 million. The net proceeds were used to repay outstanding indebtedness under our credit facility.

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 June 30, 2014:

	Payments due in twelve month periods ending:				
	Total	June 30, 2015	June 30, 2016-2017	June 30, 2018-2019	Thereafter
Long-term debt (1)	$47,031	$2,181	$4,110	$37,523	$3,217
Interest on long-term debt (2)	4,526	1,090	1,893	1,003	540
Lease obligations (3)	35	21	14	—	—
Total	$51,592	$3,292	$6,017	$38,526	$3,757

(1) These amounts represent the balances outstanding under our credit facility, the rig loan agreement and the real estate lien note. These repayments assume that we will not borrow additional funds.
(2) Interest expense assumes the balances of long-term debt at the end of the period and current effective interest rates.
(3) Lease on office space in Dickinson, North Dakota, which expires on September 30, 2014, office space in Lusk, Wyoming, which expires on December 31, 2016 and office space in Denver, Colorado, which expires December 31, 2014.

We maintain a reserve for cost associated with the retirement of tangible long-lived assets. At June 30, 2014, our reserve for these obligations totaled $9.7 million for which no contractual commitment exists. For additional information relating to this obligation, see Note 1 of the Notes to Condensed Consolidated Financial Statements.

Off-Balance Sheet Arrangements. At June 30, 2014, we had no existing off-balance sheet arrangements, as defined under SEC regulations, which have or are reasonably likely to have a current or future effect on our financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources.

Contingencies. From time to time, we are involved in litigation relating to claims arising out of our operations in the normal course of business. At June 30, 2014, we were not engaged in any legal proceedings that were expected, individually or in the aggregate, to have a material adverse effect on the Company.

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

Long-Term Indebtedness

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

	June 30, 2014	December 31, 2013
Credit facility	$37,000	$33,000
Rig loan agreement	5,586	6,378
Real estate lien note	4,445	4,554
	47,031	43,932
Less current maturities	(2,181)	(2,142)
	$44,850	$41,790

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 June 30, 2014, $37.0 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. As of June 30, 2014 we had a borrowing base of $162.5 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 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 of $162.5 million was determined based upon our reserve report dated December 31, 2013. 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 June 30, 2014 the interest rate on the credit facility was 1.9% based on 1-month LIBOR borrowings and the 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 debt to EBITDAX ratio as of the last day of each quarter of not more than 4.00 to 1.00. The current ratio is defined as the ratio of consolidated current assets to consolidated current liabilities. For the purposes of this calculation, current assets include the portion of the borrowing base which is undrawn but excludes any cash deposited with 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