Emerald Oil, Inc.
Form 10-Q
November 03, 2014

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

(Mark One)

x **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended September 30, 2014

OR

.. **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission File No. 1-35097

Emerald Oil, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**77-0639000**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1600 Broadway, Suite 1360	
Denver, CO	**80202**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: **(303) 595-5600**

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 such filing requirements for the past 90 days. Yes x No ¨

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 during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of "large accelerated filer," "accelerated filer," and "smaller reporting company" in Rule 12b-2 of the Exchange Act:

Large accelerated filer ¨	Accelerated filer x
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes ¨ No x

As of November 3, 2014, there were 66,626,245 shares of Common Stock, $0.001 par value per share, outstanding.

EMERALD OIL, INC.

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PART 1 — FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

EMERALD OIL, INC.

CONDENSED CONSOLIDATED BALANCE SHEETS

(UNAUDITED)

	September 30, 2014	December 31, 2013
ASSETS		
CURRENT ASSETS		
Cash and Cash Equivalents	$ 12,561,188	$ 144,255,438
Restricted Cash	6,000,000	15,000,512
Accounts Receivable – Oil and Natural Gas Sales	10,106,403	8,715,821
Accounts Receivable – Joint Interest Partners	32,747,260	31,523,204
Other Receivables	1,709,827	577,409
Prepaid Expenses and Other Current Assets	430,174	206,299
Fair Value of Commodity Derivatives	5,645,366	—
Total Current Assets	69,200,218	200,278,683
PROPERTY AND EQUIPMENT		
Oil and Natural Gas Properties, Full Cost Method, at cost:		
Proved Oil and Natural Gas Properties	491,003,344	211,015,067
Unproved Oil and Natural Gas Properties	168,263,288	57,015,315
Equipment and Facilities	4,976,122	1,837,744
Other Property and Equipment	1,906,488	890,811
Total Property and Equipment	666,149,242	270,758,937
Less – Accumulated Depreciation, Depletion and Amortization	(72,499,921)	(48,176,522)
Total Property and Equipment, Net	593,649,321	222,582,415
Restricted Cash	4,000,000	6,000,000
Fair Value of Commodity Derivatives	—	68,396
Debt Issuance Costs, Net of Amortization	6,471,820	475,157
Deposits on Acquisitions	773,809	125,368
Other Non-Current Assets	290,181	357,644
Total Assets	$ 674,385,349	$ 429,887,663
LIABILITIES AND STOCKHOLDERS’ EQUITY		
CURRENT LIABILITIES		
Accounts Payable	$ 98,355,284	$ 63,168,422
Fair Value of Commodity Derivatives	—	921,401
Accrued Expenses	8,575,206	11,821,729
Advances from Joint Interest Partners	2,405,972	2,205,538

Total Current Liabilities	109,336,462	78,117,090
LONG-TERM LIABILITIES		
Revolving Credit Facility	20,000,000	—
Convertible Senior Notes	172,500,000	—
Asset Retirement Obligations	2,425,731	692,137
Warrant Liability	17,454,000	15,703,000
Other Non-Current Liabilities	254,878	56,327
Total Liabilities	321,971,071	94,568,554
COMMITMENTS AND CONTINGENCIES		
Preferred Stock – Par Value $.001; 20,000,000 Shares Authorized; Series B Voting Preferred Stock – 5,114,633 issued and outstanding at September 30, 2014 and December 31, 2013. Liquidation preference value of $5,115 as of September 30, 2014 and December 31, 2013.	5,000	5,000
STOCKHOLDERS' EQUITY		
Common Stock, Par Value $.001; 500,000,000 Shares Authorized, 66,619,355 and 65,840,370 Shares Issued and Outstanding, respectively	66,619	65,840
Additional Paid-In Capital	423,337,799	416,301,344
Accumulated Deficit	(70,995,140)	(81,053,075)
Total Stockholders' Equity	352,409,278	335,314,109
Total Liabilities and Stockholders' Equity	$ 674,385,349	$ 429,887,663

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

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EMERALD OIL, INC.

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(UNAUDITED)

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
REVENUES				
Oil Sales	$28,266,332	$16,952,644	$76,989,268	$35,287,288
Natural Gas Sales	460,857	363,914	2,061,201	821,069
Net Gains (Losses) on Commodity Derivatives	11,184,716	(2,720,160)	3,722,780	(2,822,427)
Total Revenues	39,911,905	14,596,398	82,773,249	33,285,930
OPERATING EXPENSES				
Production Expenses	6,962,450	2,087,635	13,477,176	4,723,520
Production Taxes	3,142,998	1,879,160	8,632,608	3,629,557
General and Administrative Expenses	5,483,655	6,194,202	21,609,218	17,562,754
Depletion of Oil and Natural Gas Properties	9,193,566	4,497,002	24,071,676	11,238,783
Depreciation and Amortization	104,465	40,631	251,722	94,665
Accretion of Discount on Asset Retirement Obligations	28,037	7,502	63,837	21,564
Gain on Sale of Oil and Natural Gas Properties	—	(8,892,344)	—	(8,892,344)
Total Operating Expenses	24,915,171	5,813,788	68,106,237	28,378,499
INCOME FROM OPERATIONS	14,996,734	8,782,610	14,667,012	4,907,431
OTHER INCOME (EXPENSE)				
Interest Expense	(1,206,571)	(21,437)	(2,515,034)	(276,113)
Warrant Revaluation Income (Expense)	216,000	(506,000)	(1,751,000)	(4,587,000)
Other Income (Expense)	(347,088)	3,332	(343,041)	6,230
Total Other Expense, Net	(1,337,659)	(524,105)	(4,609,075)	(4,856,883)
INCOME BEFORE INCOME TAXES	13,659,075	8,258,505	10,057,937	50,548
INCOME TAX PROVISION	—	—	—	—
NET INCOME	13,659,075	8,258,505	10,057,937	50,548
Less: Preferred Stock Dividends and Deemed Dividends	—	(13,997,089)	—	(20,279,197)
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCKHOLDERS	$13,659,075	$(5,738,584)	$10,057,937	$(20,228,649)
Net Income (Loss) Per Common Share – Basic	$0.21	$(0.13)	$0.15	$(0.60)
Net Income (Loss) Per Common Share – Diluted	$0.16	$(0.13)	$0.14	$(0.60)
Weighted Average Shares Outstanding – Basic	66,499,397	42,725,711	66,335,025	33,738,417

Weighted Average Shares Outstanding –Diluted	88,380,397	42,725,711	81,867,545	33,738,417

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

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EMERALD OIL, INC.
CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(UNAUDITED)

	Nine Months Ended September 30, 2014	2013
CASH FLOWS FROM OPERATING ACTIVITIES		
Net Income	$ 10,057,937	$ 50,548
Adjustments to Reconcile Net Loss to Net Cash Provided By Operating Activities:		
Depletion of Oil and Natural Gas Properties	24,071,676	11,238,783
Depreciation and Amortization	251,722	94,665
Amortization of Debt Issuance Costs	727,997	75,618
Accretion of Discount on Asset Retirement Obligations	63,837	21,564
Gain on Sale of Oil and Natural Gas Properties	—	(8,892,344)
Net (Gains) Losses on Commodity Derivatives	(3,722,780)	2,822,427
Net Cash Settlements Paid on Commodity Derivatives	(2,775,591)	(1,597,536)
Warrant Revaluation Expense	1,751,000	4,587,000
Share-Based Compensation Expense	9,497,044	6,538,319
Changes in Assets and Liabilities:		
Decrease (Increase) in Trade Receivables – Oil and Natural Gas Revenues	(1,390,582)	7,650,021
Increase in Accounts Receivable – Joint Interest Partners	(1,224,056)	(22,095,552)
Decrease (Increase) in Other Receivables	(1,132,418)	1,061,301
Increase in Prepaid Expenses and Other Current Assets	(223,875)	(332,718)
Decrease (Increase) in Other Non-Current Assets	67,463	(305,272)
Increase in Accounts Payable	2,364,168	1,631,558
Increase (Decrease) in Accrued Expenses	(7,813,470)	5,537,377
Increase in Other Non-Current Liabilities	198,551	—
Increases in Advances from Joint Interest Partners	200,434	1,452,969
Net Cash Provided By Operating Activities	30,969,057	9,538,728
CASH FLOWS FROM INVESTING ACTIVITIES		
Purchases of Other Property and Equipment	(1,015,677)	(343,287)
Restricted Cash Released	11,000,512	—
Restricted Cash Received	—	(21,000,000)
Payments of Restricted Cash	(2,648,721)	—
Increase in Deposits for Acquisitions	(648,441)	(2,500,000)
Use of Prepaid Drilling Costs	—	98,565
Proceeds from Sale of Oil and Natural Gas Properties, Net of Transaction Costs	36,155,859	134,627,306
Investment in Oil and Natural Gas Properties	(391,368,324)	(138,610,383)
Net Cash Used For Investing Activities	(348,524,792)	(27,727,799)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from Issuance of Common Stock, Net of Transaction Costs	—	95,977,763
Proceeds from Issuance of Preferred Stock, Net of Transaction Costs	—	47,183,994
Proceeds from Issuance of Convertible Senior Notes, Net of Transaction Costs	166,893,211	—
Advances on Revolving Credit Facility	55,000,000	—

Payments on Preferred Stock	—	(35,000,000)
Payments on Revolving Credit Facility	(35,000,000)	(23,500,000)
Preferred Stock Dividends and Deemed Dividends	—	(6,899,657)
Proceeds from Exercise of Stock Options and Warrants	110,750	—
Cash Paid for Debt Issuance Costs	(1,117,871)	—
Cash Paid for Finance Costs	(24,605)	(237,500)
Net Cash Provided by Financing Activities	185,861,485	77,524,600
NET INCREASE (DECREASE) IN CASH AND CASH EQUIVALENTS	(131,694,250)	59,335,529
CASH AND CASH EQUIVALENTS – BEGINNING OF PERIOD	144,255,438	10,192,379
CASH AND CASH EQUIVALENTS – END OF PERIOD	$ 12,561,188	$ 69,527,908
Supplemental Disclosure of Cash Flow Information		
Cash Paid During the Period for Interest	$ 1,867,433	$ 255,776
Cash Paid During the Period for Income Taxes	$ —	$ —
Non-Cash Financing and Investing Activities:		
Oil and Natural Gas Properties Included in Accounts Payable	$ 92,963,874	$ 38,646,242
Stock-Based Compensation Capitalized to Oil and Natural Gas Properties	$ 2,020,992	$ 624,325
Accretion on Preferred Stock Issuance Discount	$ —	$ 8,626,000
Accrued Preferred Stock Dividend and Deemed Dividend	$ —	$ 1,932,534
Asset Retirement Obligation Costs and Liabilities	$ 1,669,757	$ 116,471
Common Stock Issued for Oil and Natural Gas Properties	$ —	$ 6,736,935

The accompanying notes are an integral part of these unaudited condensed consolidated financial statements.

EMERALD OIL, INC.
Notes to Condensed Consolidated Financial Statements
Unaudited

NOTE 1 ORGANIZATION AND NATURE OF BUSINESS

Description of Operations — Emerald Oil, Inc., a Delaware corporation ("Emerald," the "Company," "we," "us," or "our"), is Denver-based independent exploration and production company that is focused on acquiring acreage and developing wells in the Williston Basin of North Dakota and Montana. We believe the location, size and concentration of our acreage in our core project areas create an opportunity for us to achieve cost, recovery and production efficiencies through the large-scale development of our project inventory. The Company designs, drills and operates oil and natural gas wells on acreage where it holds a controlling working interest.

On June 11, 2014, the shareholders of the Company approved a measure to change our state of incorporation from Montana to Delaware. On June 11, 2014, the Company consummated a merger with our wholly owned subsidiary and, as a result, reincorporated as a Delaware corporation.

NOTE 2 BASIS OF PRESENTATION AND SIGNIFICANT ACCOUNTING POLICIES

The accompanying condensed consolidated financial statements have been prepared on the accrual basis of accounting whereby revenues are recognized when earned and expenses are recognized when incurred. The condensed consolidated financial statements as of September 30, 2014 and for the three and nine months ended September 30, 2014 and 2013 are unaudited. In the opinion of management, such financial statements include the adjustments and accruals that are of a normal recurring nature and necessary for a fair presentation of the results for the interim periods. The interim results are not necessarily indicative of results for a full year. Certain information and footnote disclosures normally included in financial statements prepared in accordance with U.S. generally accepted accounting principles ("GAAP") have been condensed or omitted in these consolidated financial statements as of September 30, 2014 and for the three and nine months ended September 30, 2014 and 2013.

Interim financial results should be read in conjunction with the audited financial statements and footnotes for the year ended December 31, 2013, which were included in the Company's Annual Report on Form 10-K for the fiscal year ended December 31, 2013.

Cash and Cash Equivalents

The Company considers highly liquid investments with insignificant interest rate risk and original maturities of three months or less to be cash equivalents. Cash equivalents consist primarily of interest-bearing bank accounts and money market funds. The Company's cash positions represent assets held in checking and money market accounts. These assets are generally available to the Company on a daily or weekly basis and are highly liquid in nature. Due to the balances being greater than the Federal Deposit Insurance Corporation (FDIC) limits of $250,000 per institution per depositor, the Company does not have insurance coverage on the entire amount of its bank deposits. The Company believes this risk to be minimal. In addition, the Company has access to Security Investor Protection Corporation protection on a vast majority of its financial assets in the event one of the brokerage firms that the Company utilizes for its investments fails.

Restricted Cash

Restricted cash included in current and long-term assets on the condensed consolidated balance sheets totaled $10 million and $21 million at September 30, 2014 and December 31, 2013, respectively. At September 30, 2014, the $10 million balance related to a drilling commitment agreement entered into pursuant to oil and natural gas leases. As of December 31, 2013, there was an additional $11.0 million of restricted cash related to a portion of proceeds from a leasehold sale held in escrow until finalization of standard due diligence procedures. On February 21, 2014, $8.6 million was released to the Company, with the remaining $2.4 million returned to the buyer for purchase price adjustments.

Accounts Receivable

The Company records estimated oil and natural gas revenue receivable from third parties at its net revenue interest. The Company also reflects costs incurred on behalf of joint interest partners in accounts receivable. Management periodically reviews accounts receivable amounts for collectability and records its allowance for uncollectible receivables under the specific identification method. The Company did not record any allowance for uncollectible receivables during the three and nine months ended September 30, 2014 and 2013.

Full Cost Method

The Company follows the full cost method of accounting for oil and natural gas operations whereby all costs related to the exploration and development of oil and natural gas properties are initially capitalized into a single cost center ("full cost pool"). Such costs include land acquisition costs, a portion of employee salaries related to property development, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling directly related to acquisitions, and exploration activities. For the three months ended September 30, 2014 and 2013, the Company capitalized $1,354,556 and $905,631, respectively, of internal salaries, which included $624,629, and $314,061, respectively, of stock-based compensation. For the nine months ended September 30, 2014 and 2013, the Company capitalized $4,278,105 and $2,124,585, respectively, of internal salaries, which included $2,020,992, and $624,325, respectively, of stock-based compensation. Internal salaries are capitalized based on employee time allocated to the acquisition of leaseholds and development of oil and natural gas properties. The Company capitalized no interest in the three and nine months ended September 30, 2014 and 2013.

Proceeds from property sales will generally be credited to the full cost pool, with no gain or loss recognized, unless such a sale would significantly alter the relationship between capitalized costs and the proved reserves attributable to these costs. No gain or loss was recognized on any sales during the three and nine months ended September 30, 2014. A gain of $8,892,344 was recognized during the three and nine months ended September 30, 2013 on one transaction that resulted in the sale of a significant portion of proved reserves as of the transaction date and significantly altered the relationship between capitalized costs and proved reserves attributable to the Williston Basin. The Company engages in acreage trades in the Williston Basin, but these trades are generally for acreage that is similar both in terms of geographic location and potential resource value.

The Company assesses all items classified as unproved property on a quarterly basis for possible impairment or reduction in value. The assessment includes consideration of the following factors, among others: intent to drill, remaining lease term, geological and geophysical evaluations, drilling results and activity, the assignment of proved reserves, and the economic viability of development if proved reserves are assigned. During any period in which these factors indicate an impairment, the cumulative drilling costs incurred to date for such property and all or a portion of the associated leasehold costs are transferred to the full cost pool and are then subject to depletion and amortization.

For the nine months ended September 30, 2014 and the year ended December 31, 2013, the Company included $3,097,089 and $3,020,485, respectively, related to expiring leases within costs subject to the depletion calculation.

Capitalized costs associated with impaired properties and properties having proved reserves, estimated future development costs, and asset retirement costs under Financial Accounting Standards Board (“FASB”) Accounting Standards Codification (“ASC”) 410-20-25 are depleted and amortized on the unit-of-production method based on the estimated gross proved reserves. The costs of unproved properties are withheld from the depletion base until such time as they are developed, impaired, or abandoned.

Under the full cost method of accounting, capitalized oil and natural gas property costs less accumulated depletion, net of deferred income taxes, may not exceed a ceiling amount equal to the present value, discounted at 10%, of estimated future net revenues from proved oil and natural gas reserves plus the cost of unproved properties not subject to amortization (without regard to estimates of fair value), or estimated fair value, if lower, of unproved properties that are subject to amortization. Should capitalized costs exceed this ceiling, which is tested on a quarterly basis, an impairment is recognized. The present value of estimated future net revenues is computed by applying prices based on a 12-month unweighted average of the oil and natural gas prices in effect on the first day of each month, less estimated future expenditures to be incurred in developing and producing the proved reserves (assuming the continuation of existing economic conditions), less any applicable future taxes. The Company performs this ceiling calculation each quarter. Any required write-downs are included in the consolidated statement of operations as an impairment charge. No ceiling test impairment was required during the three and nine months ended September 30, 2014 or 2013.

Other Property and Equipment

Property and equipment that are not oil and natural gas properties are recorded at cost and depreciated using the straight-line method over their estimated useful lives of three to seven years. Expenditures for replacements, renewals, and betterments are capitalized. Maintenance and repairs are charged to expense as incurred.

ASC 360-10-35-21 requires that long-lived assets, other than oil and natural gas properties, be reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. The determination of impairment is based upon expectations of undiscounted future cash flows, before interest, of the related asset. If the carrying value of the asset exceeds the undiscounted future cash flows, the impairment would be computed as the difference between the carrying value of the asset and the fair value. The Company has not recognized any impairment losses on non-oil and natural gas long-lived assets.

Asset Retirement Obligations

The Company records the fair value of a liability for an asset retirement obligation in the period in which the well is spud or the asset is acquired and a corresponding increase in the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depleted using the units of production method. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized.

Revenue Recognition and Natural Gas Balancing

The Company recognizes oil and natural gas revenues from its interests in producing wells when production is delivered and title has transferred to the purchaser, to the extent the selling price is reasonably determinable. The Company uses the sales method of accounting for balancing of natural gas production and would recognize a liability if the existing proved reserves were not adequate to cover the current imbalance situation. As of September 30, 2014 and December 31, 2013, the Company’s natural gas production was in balance, i.e., its cumulative portion of natural gas production taken and sold from wells in which it has an interest equaled the Company’s entitled interest in natural gas production from those wells.

Stock-Based Compensation

The Company accounts for stock-based compensation under the provisions of ASC 718-10-55. The Company recognizes stock-based compensation expense in the financial statements over the vesting period of equity-classified employee stock-based compensation awards based on the grant date fair value of the awards, net of estimated forfeitures. For options and warrants, the Company uses the Black-Scholes option valuation model to calculate the fair value of stock based compensation awards at the date of grant. Option pricing models require the input of highly subjective assumptions, including the expected price volatility. For the stock options and warrants granted, the Company has used a variety of comparable and peer companies to determine the expected volatility input based on the expected term of the options. The Company believes the use of peer company data fairly represents the expected volatility it would experience if it were in the oil and natural gas industry over the expected term of the options. The Company used the simplified method to determine the expected term of the options due to the lack of historical data. Changes in these assumptions can materially affect the fair value estimate.

On May 27, 2011, the stockholders of the Company approved the 2011 Equity Incentive Plan (the "2011 Plan"), under which 714,286 shares of common stock were reserved. On October 22, 2012 and July 10, 2013, the stockholders of the Company approved an amendment to the 2011 Plan to increase the number of shares available for issuance under the 2011 Plan to 3,500,000 shares and 9,800,000 shares, respectively. The purpose of the 2011 Plan is to promote the success of the Company and its affiliates by facilitating the employment and retention of competent personnel and by furnishing incentives to those officers, directors and employees upon whose efforts the success of the Company and its affiliates will depend to a large degree. It is the intention of the Company to carry out the 2011 Plan through the granting of incentive stock options, nonqualified stock options, restricted stock awards, restricted stock unit awards, performance awards and stock appreciation rights. As of September 30, 2014, 1,409,055 stock options and 4,124,902 shares of restricted common stock and restricted stock units had been issued to officers, directors and employees under the 2011 Plan net of cancelations and forfeitures, including 1,398,564 nonvested restricted stock units. As of September 30, 2014, there were 4,266,043 shares available for issuance under the 2011 Plan.

Income Taxes

The Company accounts for income taxes under ASC 740-10-30. Deferred income tax assets and liabilities are determined based upon differences between the financial reporting and tax bases of assets and liabilities and are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. Accounting standards require the consideration of a valuation allowance for deferred tax assets if it is "more likely than not" that some component or all of the benefits of deferred tax assets will not be realized.

The tax effects from an uncertain tax position can be recognized in the financial statements only if the position is more likely than not of being sustained if the position were to be challenged by a taxing authority. The Company has examined the tax positions taken in its tax returns and determined that there are no uncertain tax positions. As a result, the Company has recorded no uncertain tax liabilities in its consolidated balance sheet.

Net Income (Loss) Per Common Share

Basic net income (loss) per common share is based on the net income (loss) divided by the weighted average number of common shares outstanding during the period. Diluted earnings per share are computed using the weighted average number of common shares plus dilutive common share equivalents outstanding during the period using the treasury stock method. In the computation of diluted earnings per share, excess tax benefits that would be created upon the assumed vesting of nonvested restricted shares or the assumed exercise of stock options (i.e., hypothetical excess tax benefits) are included in the assumed proceeds component of the treasury stock method to the extent that such excess tax benefits are more likely than not to be realized. When a loss from continuing operations exists, all potentially dilutive securities are anti-dilutive and are therefore excluded from the computation of diluted earnings per share.

The reconciliation of the denominators used to calculate basic EPS and diluted EPS for the three and nine months ended September 30, 2014 and 2013 are as follows:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Weighted Average Common Shares Outstanding – Basic	66,499,397	42,725,711	66,335,025	33,738,417
Plus: Potentially Dilutive Common Shares				
Convertible Senior Notes	19,658,120	—	13,681,475	—
Stock Options and Restricted Stock Units	944,581	—	780,057	—

Warrants	1,278,299	—	1,070,988	—
Weighted Average Common Shares Outstanding – Diluted	88,380,397	42,725,711	81,867,545	33,738,417
Restricted Stock Units Excluded from EPS due to the Anti-Dilutive Effect	—	2,281,096	9,941	2,281,096
Stock Options Excluded from EPS due to the Anti-Dilutive Effect	185,346	1,113,703	122,316	1,113,703
Warrants Excluded from EPS due to the Anti-Dilutive Effect	892,858	1,116,151	892,858	1,116,151
Convertible Note Interest Expense Added Back to Earnings	$ 862,500	$ —	$ 1,782,500	$ —

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Derivative and Other Financial Instruments

Commodity Derivative Instruments

The Company has entered into commodity derivative instruments, utilizing oil derivative swap contracts to reduce the effect of price changes on a portion of future oil production. The Company’s commodity derivative instruments are measured at fair value and are included in the consolidated balance sheet as derivative assets and liabilities. Net gains and losses are recorded based on the changes in the fair values of the derivative instruments. The Company’s valuation estimate takes into consideration the counterparties’ credit worthiness, the Company’s credit worthiness, and the time value of money. The consideration of the factors results in an estimated exit price for each derivative asset or liability under a market place participant’s view. Management believes that this approach provides a reasonable, non-biased, verifiable, and consistent methodology for valuing commodity derivative instruments (see Note 12 – Derivative Instruments and Price Risk Management).

Warrant Liability

From time to time, the Company may have financial instruments such as warrants that may be classified as liabilities when (a) the holders possess rights to net cash settlement, (b) physical or net equity settlement is not in the Company’s control, or (c) the instruments contain other provisions that causes the Company to conclude that they are not indexed to the Company’s equity. Such instruments are initially recorded at fair value and subsequently adjusted to fair value at the end of each reporting period through earnings.

As a part of a securities purchase agreement entered into in February 2013 with affiliates of White Deer Energy L.P. (see Note 5 – Preferred and Common Stock), the Company issued warrants that contain a put and other liability-type provisions. Accordingly, these warrants are accounted for as a liability. This warrant liability is accounted for at fair value with changes in fair value reported in the consolidated statements of operations.

New Accounting Pronouncements

From time to time, new accounting pronouncements are issued by FASB that are adopted by the Company as of the specified effective date. If not discussed, management believes that the impact of recently issued standards, which are not yet effective, will not have a material impact on the Company’s consolidated financial statements upon adoption.

Use of Estimates

The preparation of consolidated financial statements under GAAP in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. The most significant estimates relate to proved oil and natural gas reserve volumes, future development costs, estimates relating to certain oil and natural gas revenues and expenses, fair value of derivative instruments, valuation of share-based compensation and the valuation of deferred income taxes. Actual results may differ from those estimates.

Industry Segment and Geographic Information

The Company operates in one industry segment, which is the exploration, development and production of oil and natural gas with all of the Company’s operational activities having been conducted in the U.S. The Company’s current operational activities and the Company’s consolidated revenues are generated from markets exclusively in the U.S., and the Company has no long-lived assets located outside the U.S.

Reclassifications

Certain reclassifications have been made to amounts reported in prior periods in order to conform to the current period presentation. These reclassifications did not impact the Company's net loss, stockholders' equity or cash flows.

NOTE 3 OIL AND NATURAL GAS PROPERTIES

The value of the Company's oil and natural gas properties consists of all acreage acquisition costs (including cash expenditures and the value of stock consideration), drilling costs and other associated capitalized costs. Acquisitions are accounted for as purchases and, accordingly, the results of operations are included in the accompanying condensed consolidated statements of operations from the closing date of the acquisition. Purchase prices are allocated to acquired assets based on their estimated fair value at the time of the acquisition. The Company has historically funded acquisitions with internal cash flow, the issuance of equity or debt securities and short-term borrowings under its revolving credit facility.

Acquisitions

In February 2014, the Company acquired approximately 19,500 net acres located in Williams and McKenzie Counties, North Dakota from an unrelated third party for approximately $69.2 million in cash. Net daily production from the acreage was approximately 300 Boe/d as of January 1, 2014, the effective date of the transaction. The acquisition was accounted for as an asset purchase. Related transaction costs were capitalized to oil and natural gas properties.

In February 2014, the Company acquired approximately 5,900 net acres of undeveloped leasehold located in McKenzie and Billings Counties, North Dakota from an unrelated third party for approximately $10.3 million in cash.

On September 2, 2014 the Company acquired approximately 30,500 net acres located in McKenzie, Billings and Dunn Counties of North Dakota from an unrelated third party for approximately $71.2 million in cash and the assignment of 4,300 net acres located in Williams County, North Dakota.

The following table summarizes the purchase price and estimated values of assets acquired and liabilities assumed for the September acquisition:

Purchase Price

Consideration Given:	
Cash	$71,187,000
Assignment of oil and natural gas properties	35,918,000
Liabilities assumed, net	1,121,000
Total	$108,226,000
Allocation of Purchase Price:	
Proved oil and natural gas properties	$56,607,000
Unproved oil and natural gas properties	51,473,000
Liabilities released	146,000
Total fair value of oil and natural gas properties	$108,226,000

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Pro Forma Operating Results

In accordance with ASC Topic 805, presented below are unaudited pro forma results for the three and nine months ended September 30, 2014 and 2013 to show the effect on our consolidated results of operations as if the September acquisition had occurred on January 1, 2013.

The pro forma results reflect the results of combining our statement of operations with the results of operations from the oil and natural gas properties acquired during 2014, adjusted for (i) the assumption of asset retirement obligations and accretion expense for the properties acquired and (ii) depletion expense applied to the adjusted basis of the properties acquired. The pro forma information is based upon these assumptions and is not necessarily indicative of future results of operations:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Revenues	$ 43,160,959	$ 17,595,615	$ 95,151,146	$ 39,112,553
Net Income (Loss) Available to Common Stockholders	$ 14,860,956	$ (4,675,588)	$ 14,723,060	$ (18,246,040)
Net Income (Loss) Per Share - Basic	$ 0.22	$ (0.11)	$ 0.22	$ (0.54)
Net Income (Loss) Per Share - Diluted	$ 0.18	$ (0.11)	$ 0.20	$ (0.54)
Weighted Average Shares Outstanding - Basic	66,499,397	42,725,711	66,335,025	33,738,417
Weighted Average Shares Outstanding - Diluted	88,380,397	42,725,711	81,867,545	33,738,417

Post-Acquisition Operating Results

The amount of revenues and excess of revenues over direct operating expenses included in the accompanying Consolidated Statements of Operations for the September acquisition is shown in the table that follows. Direct operating expenses include lease operating expenses, selling, general and administrative expenses and production and other taxes.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Revenues	$ 1,157,798	$ —	$ 1,157,798	$ —
Excess of revenues over direct operating expenses	$ 964,299	$ —	$ 964,299	$ —

NOTE 4 RELATED PARTY TRANSACTIONS

In February 2013, the Company entered into a securities purchase agreement (the "Securities Purchase Agreement") with affiliates of White Deer Energy L.P. ("White Deer Energy"), pursuant to which the Company issued to White Deer Energy 500,000 shares of Series A Perpetual Preferred Stock ("Series A Preferred Stock"), 5,114,633 shares of Series B Voting Preferred Stock ("Series B Preferred Stock") and warrants to purchase an initial aggregate amount of 5,114,633 shares of the Company's common stock at an initial exercise price of $5.77 per share, for an aggregate $50 million. Pursuant to the Securities Purchase Agreement, White Deer Energy obtained the right to designate one member of the Company's board of directors as long as White Deer Energy held any shares of Series A Preferred Stock. White Deer Energy designated Thomas J. Edelman as its initial director. Following the redemption of the Series A Preferred Stock during 2013, the Governance and Nominating Committee of the Company nominated Mr. Edelman to continue to serve as a director of the Company, and Mr. Edelman was elected to serve on the board of directors of the Company for another term at the annual stockholders meeting of the Company held in June 2014. For additional information regarding the Securities Purchase Agreement with White Deer Energy, see Note 5 — Preferred and Common Stock.

The transaction was subject to customary closing conditions, as well as the execution and delivery of certain other agreements, including a registration rights agreement. Under the terms of the registration rights agreement, as amended, the Company agreed to file with the Securities and Exchange Commission (the “SEC”), within 30 days upon receipt of notice from White Deer Energy, a shelf registration statement covering resales of the 5,114,633 shares of Company common stock issuable upon exercise of the warrants and use commercially reasonable efforts to cause such registration statement to be declared effective within 120 days after the filing thereof. In June 2013 and October 2013, the Company amended the registration rights agreement to include 2,785,600 shares of Company common stock and 5,092,852 shares of Company common stock, respectively, issued to White Deer Energy in connection with subsequent private placements. On April 19, 2014, the Company received a request from White Deer Energy to register the shares of Company common stock and the shares of Company common stock underlying the warrants held by White Deer Energy. On May 16, 2014, the Company filed with the SEC a registration statement on Form S-3 to register for resale the 7,878,452 shares of common stock and 5,114,633 shares of common stock underlying the warrants held by White Deer Energy, and the SEC declared the registration statement effective on May 30, 2014.

NOTE 5 PREFERRED AND COMMON STOCK

Preferred Stock

On February 19, 2013, the Company issued to White Deer Energy 500,000 shares of Series A Preferred Stock, 5,114,633 shares of Series B Preferred Stock and warrants to purchase an initial aggregate 5,114,633 shares of the Company’s common stock at an initial exercise price of $5.77 per share, in exchange for an aggregate $50 million. The warrants are exercisable until December 31, 2019.

On various dates throughout 2013, the Company redeemed all of the outstanding shares of Series A Preferred Stock, including principal of $50,000,000 and redemption premiums of $6,250,000, and no shares of Series A Preferred Stock remained outstanding as of September 30, 2014. For each redemption, the redemption premium was treated as a dividend and recorded as a return of equity to White Deer Energy through a charge to the Company’s additional paid-in capital. The Company paid no dividends during the three and nine months ended September 30, 2014. For the three and nine months ended September 30, 2013, the Company paid dividends on the Series A Preferred Stock of $706,849 and $2,524,658, respectively.

The Series B Preferred Stock is entitled to vote, until January 1, 2020, in the election of directors and on all other matters submitted to a vote of the holders of common stock as a single class. Each share of Series B Preferred Stock has one vote. The Series B Preferred Stock has no dividend rights and a liquidation preference of $0.001 per share. On and from time to time after January 1, 2020 the Company may redeem, in whole or in part, the then-outstanding shares of Series B Preferred Stock, at a redemption price per share equal to $0.001. Each share of Series B Preferred Stock was issued as part of a unit with a warrant to purchase one share of common stock and will be surrendered to the

Company upon exercise of a warrant.

The warrants entitle White Deer Energy to acquire 5,114,633 shares of common stock at $5.77 per share and surrendering an equal number of shares of Series B Preferred Stock to the Company. See Note 12 – Derivative Instruments and Price Risk Management – Warrant Liability for further discussion of the warrants.

Upon a change of control or liquidation event, as defined in the Securities Purchase Agreement, White Deer Energy had the right, but not the obligation, to elect to receive from the Company, in exchange for all, but not less than all, shares of Series A Preferred Stock, Series B Preferred Stock and the warrants, as well as shares of common stock issued upon exercise of the warrant that were then held by White Deer Energy, an additional cash payment necessary to achieve a minimum internal rate of return of 25%. Upon the final redemption of the shares Series A Preferred Stock on October 15, 2013, the Company and White Deer Energy agreed the minimum internal rate of return had been achieved and no additional cash payment to White Deer Energy would be necessary upon a change of control or liquidation event.

The Company recorded the White Deer Energy private placement by recognizing the fair value of the Series A Preferred Stock at $38,552,994 (net of offering costs of $2,816,006), Series B Preferred Stock at $5,000 and a warrant liability of $8,626,000 at time of issuance. The Company accreted the Series A Preferred Stock to the liquidation or redemption value when it became probable that the event or events underlying the liquidation or redemption of the Series A Preferred Stock were probable. The Company recognized all issuance discount accretion related to the partial redemptions of preferred stock on June 20, 2013, August 30, 2013 and October 15, 2013. There was no issuance discount remaining as of September 30, 2014.

A summary of the preferred stock transaction components as of September 30, 2014 and December 31, 2013 is provided below:

	September 30, 2014	December 31, 2013
Series A Preferred Stock	$ —	$ —
Series B Preferred Stock	5,000	5,000
Warrant Liability	17,454,000	15,703,000
Total	$ 17,459,000	$ 15,708,000

<u>Restricted Stock Awards and Restricted Stock Unit Awards</u>

The Company incurred compensation expense associated with restricted stock and restricted stock units granted of $2,480,352 and $3,788,391 for the three months ended September 30, 2014 and 2013, respectively, and $8,686,625 and $5,578,117 for the nine months ended September 30, 2014 and 2013, respectively. As of September 30, 2014, there were 1,398,564 non-vested restricted stock units and $3,579,245 associated remaining unrecognized compensation expense, which is expected to be recognized over the weighted-average period of 0.60 years. The Company capitalized compensation expense associated with the restricted stock and restricted stock units of $437,612 and $285,148 to oil and natural gas properties for the three months ended September 30, 2014 and 2013, respectively, and $1,425,364 and $285,148 for the nine months ended September 30, 2014 and 2013, respectively. Approximately $919,633 of the compensation expense associated with restricted stock and restricted stock units during the three months ended September 30, 2014 related to the modification and accelerated vesting of restricted stock unit grants associated with severance to a prior officer of the Company. A total of 213,228 restricted stock units associated with the severance vested on September 10, 2014. There is no remaining unamortized expense associated with the severance as of September 30, 2014.

A summary of the restricted stock units and restricted stock shares activity during the nine months ended September 30, 2014 is as follows:

	Number of Shares	Weighted Average Grant Date Fair Value
Non-vested restricted stock and restricted stock units at January 1, 2014	2,082,187	$ 5.73
Granted	264,134	7.48
Canceled	—	—
Vested and forfeited for taxes	(379,103)	5.81
Vested and issued	(568,654)	5.81
Non-vested restricted stock and restricted stock units at September 30, 2014	1,398,564	$ 6.01

NOTE 6 STOCK OPTIONS AND WARRANTS

Stock Options

On January 10, 2014, the Company granted stock options to certain employees to purchase a total of 295,800 shares of common stock exercisable at $7.48 per share. The options vest on an annual basis over 36 months with 98,600 options vesting on January 10, 2015, 2016 and 2017.

On April 1, 2014, the Company granted stock options to certain employees to purchase a total of 255,499 shares of common stock exercisable at $6.69 per share. The options vest on an annual basis over 36 months with 85,166 options vesting on April 1, 2015, 2016 and 2017.

On July 1, 2014, the Company granted stock options to certain employees to purchase a total of 7,700 shares of common stock exercisable at $7.65 per share. The options vest on an annual basis over 36 months with 2,566 options vesting on July 1, 2015, 2016 and 2017.

On September 22, 2014, the Company granted stock options to certain employees to purchase a total of 19,000 shares of common stock exercisable at $6.80 per share. The options vest on an annual basis over 36 months with 6,333 options vesting on September 22, 2015, 2016 and 2017.

The total fair value of stock options granted during the three and nine months ended September 30, 2014 was calculated using the Black-Scholes valuation model based on factors present at the time the options were granted. The following assumptions were used for the Black-Scholes model to value the options granted during the nine-month period ended September 30, 2014.

Risk free rates	0.58% to 1.42%
Dividend yield	0%
Expected volatility	56.16% to 67.70%
Weighted average expected life	3.5 years

The impact on the Company’s statement of operations of stock-based compensation expense related to options granted for the three months ended September 30, 2014 and 2013 was $337,809 and $384,130, respectively, net of $0 tax. The impact on the Company’s statement of operations of stock-based compensation expense related to options granted for the nine-month periods ended September 30, 2014 and 2013 was $810,419 and $960,202, respectively, net of $0 tax. The Company capitalized $187,017, and $28,913 in compensation to oil and natural gas properties related to outstanding options for the three months ended September 30, 2014 and 2013, respectively, and $595,628 and $250,074 for the nine months ended September 30, 2014 and 2013, respectively. The Company had $1,281,834 of total unrecognized compensation cost related to nonvested stock options granted as of September 30, 2014. The remaining cost is expected to be recognized over a weighted-average period of 1.16 years. These estimates are subject to change based on a variety of future events which include, but are not limited to, changes in estimated forfeiture rates, cancellations and the issuance of new options.

A summary of the stock options activity during the nine months ended September 30, 2014 is as follows:

	Number of Options	Weighted Average Exercise Price
Balance outstanding at January 1, 2014	1,158,860	$ 8.90
Granted	577,999	7.11
Canceled	(273,099)	8.46
Exercised	(75,000)	4.43
Balance outstanding at September 30, 2014	1,388,760	$ 8.48
Options exercisable at September 30, 2014	597,631	$ 10.17

At September 30, 2014, stock options outstanding were as follows:

	Options Outstanding			Options Exercisable		
Year of Grant	Number of Options Outstanding	Weighted Average Remaining Contract Life (years)	Weighted Average Exercise Price	Number of Options Exercisable	Weighted Average Remaining Contract Life (years)	Weighted Average Exercise Price
2014	528,199	4.27	$ 7.12	94,066	3.38	$ 7.48
2013	380,001	6.07	7.11	96,667	6.59	6.60
2012	357,142	2.40	8.11	283,480	2.28	8.18
Prior	123,418	1.46	19.58	123,418	1.46	19.58
Total	1,388,760	4.03	$ 8.48	597,631	3.00	$ 10.17

Warrants

The table below reflects the status of warrants outstanding at September 30, 2014:

	Warrants	Exercise Price	Expiration Date
December 1, 2009	37,216	$ 6.86	December 1, 2019
December 31, 2009	186,077	$ 6.86	December 31, 2019
February 8, 2011	892,858	$ 49.70	February 8, 2016
February 19, 2013	5,114,633	$ 5.77	December 31, 2019
Total	6,230,784		

No warrants expired or were forfeited during the nine months ended September 30, 2014. All of the compensation expense related to the applicable vested warrants issued to employees has been expensed by the Company prior to 2012. All warrants outstanding were exercisable at September 30, 2014. See Note 12 – Derivative Instruments and Price Risk Management for details on the treatment of the warrants issued on February 19, 2013.

NOTE 7 REVOLVING CREDIT FACILITY

On November 20, 2012, the Company entered into a senior secured revolving credit facility (the “Credit Facility”) with Wells Fargo Bank, N.A., as administrative agent (“Wells Fargo”), and the lenders party thereto. The Credit Facility is a senior secured reserve-based revolving credit facility with a maximum commitment of $400 million. As of September 30, 2014, the Company had drawn $20.0 million toward its $200 million borrowing base under the Credit Facility.

Amounts borrowed under the Credit Facility will mature on September 30, 2018, and upon such date, any amounts outstanding under the Credit Facility are due and payable in full. Redeterminations of the borrowing base are made on a semi-annual basis, with an option to elect an additional redetermination every six months between the semi-annual redeterminations.

The annual interest cost under the Credit Facility, which is dependent upon the percentage of the borrowing base utilized, is, at the Company's option, based on either the Alternate Base Rate (as defined under the terms of the Credit Facility) plus 0.75% to 1.75% or the London Interbank Offer Rate (LIBOR) plus 1.75% to 2.75%; provided, in no event may the interest rate exceed the maximum interest rate allowed by any current or future law. Interest on ABR Loans is due and payable on a quarterly basis, and interest on Eurodollar Loans is due and payable, at the Company's option, at one-, two-, three-, six- (or in some cases nine- or twelve-) month intervals. The Company also pays a commitment fee ranging from 0.375% to 0.5%, depending on the percentage of the borrowing base utilized. As of September 30, 2014, the annual interest rate on the Credit Facility was 2.29%.

A portion of the Credit Facility not in excess of $5 million will be available for the issuance of letters of credit by Wells Fargo. The Company will pay a rate per annum ranging from 1.75% to 2.75% on the face amount of each letter of credit issued and will pay a fronting fee equal to the greater of $500 and 0.125% of the face amount of each letter of credit issued. As of September 30, 2014, the Company has not obtained any letters of credit under the Credit Facility.

Each of the Company's subsidiaries is a guarantor under the Credit Facility. The Credit Facility is secured by first priority, perfected liens and security interests on substantially all assets of the Company and the guarantors, including a pledge of their ownership in their respective subsidiaries.

The Credit Facility contains customary covenants that include, among other things: limitations on the ability of the Company to incur or guarantee additional indebtedness; create liens; pay dividends on or repurchase stock; make certain types of investments; enter into transactions with affiliates; and sell assets or merge with other companies. The Credit Facility also requires compliance with certain financial covenants, including, (a) a ratio of current assets to current liabilities of at least 1.00 to 1.00, (b) a maximum ratio of total debt to EBITDA for the preceding four fiscal quarters of no more than 4.00 to 1.00. For any fiscal quarter ending in calendar year 2014, total debt is reduced by cash equivalents less $10,000,000 for purposes of calculating the total debt to EBITDA ratio. The Company was in compliance with all covenants under the Credit Facility as of September 30, 2014.

The Credit Facility allows the Company to hedge up to 60% of proved reserves for the first 24 months and 80% of projected production from proved developed producing reserves from 24 months up to 60 months later provided that in no event shall the aggregate amount of hedges exceed 100% of actual production in the current period.

NOTE 8 CONVERTIBLE NOTES

On March 24, 2014, the Company completed a private placement of $172.5 million in aggregate principal amount of 2.0% Convertible Notes (the "Convertible Notes"), and entered into an indenture (the "Indenture") governing the

Convertible Notes, with U.S. Bank National Association, as trustee (the “Trustee”). The Convertible Notes accrue interest at a rate of 2.00% per year, payable semiannually in arrears on April 1 and October 1 of each year, beginning on October 1, 2014. The Convertible Notes mature on April 1, 2019. The Convertible Notes are the Company’s unsecured senior obligations and are equal in right of payment to the Company’s existing and future senior indebtedness. The Convertible Notes were convertible into approximately 19,658,120 shares of common stock as of September 30, 2014. However, the Company does not believe conversion will take place due to the term remaining on the Convertible Notes, and in the event of conversion, holders would forgo all future interest payments and the possibility of further stock price appreciation. As a result, the Convertible Notes have been classified as long-term debt as of September 30, 2014.

The net proceeds from the Convertible Notes were $166.9 million, after deducting commissions and the offering expenses payable by the Company. The Company’s transaction costs in conjunction with the transaction will be amortized to interest expense over the five-year term of the Convertible Notes.

The Convertible Notes and the common stock issuable upon conversion of the Convertible Notes have not been registered under the Securities Act of 1933, as amended (the “Securities Act”), or the securities laws of any other jurisdiction, and may not be offered or sold in the United States absent registration or an applicable exemption from registration requirements. The Convertible Notes were offered and sold to the initial purchasers in a private placement exempt from the registration requirements of the Securities Act pursuant to Section 4(a)(2). The Convertible Notes were resold by the initial purchasers to qualified institutional buyers in reliance on Rule 144A under the Securities Act.

Holders may convert their Convertible Notes at their option at any time prior to the close of business on the business day immediately preceding the maturity date of the Convertible Notes. The conversion rate for the Convertible Notes is initially 113.9601 shares of the Company’s common stock per $1,000 principal amount of Convertible Notes (which represents an initial conversion price of approximately $8.78 per share of the Company’s common stock), subject to certain anti-dilution adjustments as provided in the Indenture. A holder that surrenders its Convertible Notes for conversion in connection with a Make-Whole Fundamental Change (as defined in the Indenture) that occurs before the maturity date may in certain circumstances be entitled to an increased conversion rate. If the Company undergoes a Fundamental Change (as defined in the Indenture), subject to certain conditions, the holder of the Convertible Notes will have the option to require the Company to repurchase all or any portion of its Convertible Notes for cash. The fundamental change purchase price will be 100% of the principal amount of the Convertible Notes to be purchased, plus any accrued and unpaid interest, including additional interest, if any, to, but excluding, the fundamental change purchase date. The Company may not redeem the Convertible Notes prior to their maturity, and no sinking fund is provided for the Convertible Notes.

The Company does not intend to file a shelf registration statement for resale of the Convertible Notes or the shares of its common stock issuable upon conversion of the Convertible Notes. The Company will, however, be required to pay additional interest in respect of the Convertible Notes under specified circumstances. As a result, holders may only resell the Convertible Notes or shares of the Company’s common stock issued upon conversion of the Convertible Notes, if any, pursuant to an exemption from the registration requirements of the Securities Act and other applicable securities laws.

The Indenture contains customary terms and covenants and events of default. If an Event of Default (as defined in the Indenture) occurs and is continuing, the Trustee or the holders of at least 25% in aggregate principal amount of the then outstanding Convertible Notes may declare by written notice all the Convertible Notes to be immediately due and payable in full. The Company was in compliance with all covenants as of September 30, 2014.

NOTE 9 ASSET RETIREMENT OBLIGATION

The Company has asset retirement obligations associated with the future plugging and abandonment of its proved oil and natural gas properties and related facilities. Under the provisions of ASC 410-20-25, the fair value of a liability for an asset retirement obligation is recorded in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. The liability is accreted to its present value each period, and the capitalized cost is depleted using the units of production method. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. The fair value of additions to the asset retirement obligations is estimated using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation include estimates of: (i) plugging and abandonment costs per well based on existing regulatory requirements; (ii) remaining life per well; (iii) future inflation factors (average of 2.5% for each of the periods presented); and (iv) a credit-adjusted risk-free interest rate (average of 7.0% for each of the periods presented). These inputs require significant judgments and estimates by the Company’s management at the time of the valuation and are the most sensitive and subject to change. The Company has no assets that are legally restricted for purposes of settling asset retirement obligations.

The following table summarizes the Company’s asset retirement obligation transactions recorded in accordance with the provisions of ASC 410-20-25 for the nine months ended September 30, 2014 and the year ended December 31, 2013:

	Nine Months Ended September 30, 2014	Year Ended December 31, 2013
Beginning Asset Retirement Obligation	$ 692,137	$ 296,074
Revision of Previous Estimates	—	165,968
Liabilities Incurred or Acquired	1,689,074	510,271

Accretion of Discount on Asset Retirement Obligations	63,837	32,449
Liabilities Associated with Properties Sold	(19,317)	(312,625)
Ending Asset Retirement Obligation	$ 2,425,731	$ 692,137

NOTE 10 INCOME TAXES

Deferred income tax assets and liabilities are determined based upon differences between the financial reporting and tax bases of assets and liabilities and are measured using the enacted tax rates and laws that will be in effect when the differences are expected to reverse. Accounting standards require the consideration of a valuation allowance for deferred tax assets if it is “more likely than not” that some component or all of the benefits of deferred tax assets will not be realized. As of September 30, 2014 and December 31, 2013, the Company maintained a full valuation allowance for all deferred tax assets. Based on these requirements no provision or benefit for income taxes has been recorded for deferred taxes. There were no recorded unrecognized tax benefits at the end of the reporting period.

NOTE 11 FAIR VALUE

ASC 820-10-55 defines fair value, establishes a framework for measuring fair value under GAAP and enhances disclosures about fair value measurements. Fair value is defined under ASC 820-10-55 as the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. Valuation techniques used to measure fair value must maximize the use of observable inputs and minimize the use of unobservable inputs. The standard describes a fair value hierarchy based on three levels of inputs, of which the first two are considered observable and the last unobservable, that may be used to measure fair value which are the following:

Level 1 – Unadjusted quoted prices in active markets that are accessible at measurement date for identical assets or liabilities.

Level 2 - Inputs other than Level 1 that are observable, either directly or indirectly, such as quoted prices for similar assets or liabilities; quoted prices in markets that are not active; or other inputs that are observable or can be corroborated by observable market data for substantially the full term of the assets or liabilities.

Level 3 - Unobservable inputs that are supported by little or no market activity and that are significant to the fair value of the assets or liabilities and less observable from objective sources.

The level in the fair value hierarchy within which the fair value measurement is categorized is based on the lowest level 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 requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The Company's policy is to recognize transfer in and/or out of fair value hierarchy as of the end of the reporting period for which the event or change in circumstances caused the transfer. The Company has consistently applied the valuation techniques discussed below for the periods presented. These valuation policies are determined by the Company's Vice President of Accounting and approved by the Chief Financial Officer. The valuation policies are discussed with the Company's Audit Committee as deemed appropriate. Each quarter, the Vice President of Accounting and Chief Financial Officer update the inputs used in the fair value measurement and internally review the changes from period to period for reasonableness. The Company uses data from peers as well as external sources in the determination of the volatility and risk free rates used in the Company's fair value calculations. A sensitivity analysis is performed as well to determine the impact of inputs on the ending fair value estimate.

Fair Value on a Recurring Basis

The following schedule summarizes the valuation of financial instruments measured at fair value on a recurring basis in the condensed consolidated balance sheet as of September 30, 2014:

	Fair Value Measurements at September 30, 2014 Using		
	Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Warrant Liability – Long Term Liability	$—	$ —	$ (17,454,000)
Commodity Derivatives – Current Asset (oil swaps)	—	5,645,366	—
Total	$—	$ 5,645,366	$ (17,454,000)

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The following schedule summarizes the valuation of financial instruments measured at fair value on a recurring basis in the condensed consolidated balance sheet as of December 31, 2013:

	Fair Value Measurements at December 31, 2013 Using Quoted Prices In Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)
Warrant Liability – Long Term Liability	$—	$ —	$ (15,703,000)
Commodity Derivatives – Current Liability (oil swaps)	—	(921,401)	—
Commodity Derivatives – Long Term Asset (oil swaps)	—	68,396	—
Total	$—	$ (853,005)	$ (15,703,000)

Level 2 assets consist of commodity derivative assets and liabilities (see Note 12 – Derivative Instruments and Price Risk Management). The fair value of the commodity derivative assets and liabilities are estimated by the Company using the income valuation techniques utilizing an option pricing or discounted cash flow model, as appropriate, which take into account notional quantities, market volatility, market prices, contract parameters and discount rates based on published LIBOR rates. The Company validates the data provided by third parties by understanding the pricing models used, obtaining market values from other pricing sources, analyzing pricing data in certain situations and confirming that those securities trade in active markets. Assumed credit risk adjustments, based on published credit ratings, public bond yield spreads and credit default swap spreads, are applied to the Company's commodity derivatives. Significant changes in the quoted forward prices for commodities and changes in market volatility generally leads to corresponding changes in the fair value measurement of the Company's oil derivative contracts. The fair value of all derivative contracts is reflected on the consolidated balance sheets.

A rollforward of Level 3 warrant liability measured at fair value using Level 3 on a recurring basis is as follows (in thousands):

Balance, at January 1, 2013	$—
Purchases, issuances, and settlements	(8,626,000)
Change in Fair Value of Warrant Liability	(7,077,000)
Balance, at December 31, 2013	(15,703,000)

Change in Fair Value of Warrant Liability	(1,751,000)
Balance, at September 30, 2014	$(17,454,000)

The fair value of the warrants upon issuance to White Deer Energy on February 19, 2013 was recorded at $8,626,000. The warrant revaluation income (expense) was $216,000 and $(506,000) for the three months ended September 30, 2014 and 2013, respectively, and $(1,751,000) and $(4,587,000) for the nine months ended September 30, 2014 and 2013, respectively. The warrant revaluation expense is included in Other Income/Expense on the accompanying Condensed Consolidated Statements of Operations. See discussion of assumptions used in valuing the warrants at Note 12 – Derivative Instruments and Price Risk Management.

Nonrecurring Fair Value Measurements

The Company follows the provisions of ASC 820-10 for nonfinancial assets and liabilities measured at fair value on a nonrecurring basis. As it relates to the Company, ASC 820-10 applies to certain nonfinancial assets and liabilities as may be acquired in a business combination and thereby measured at fair value and the initial recognition of asset retirement obligations for which fair value is used.

The asset retirement obligation estimates are derived from historical costs as well as management's expectation of future cost environments. As there is no corroborating market activity to support the assumptions used, the Company has designated these liabilities as Level 3. A reconciliation of the beginning and ending balances of the Company's asset retirement obligation is presented in Note 9 – Asset Retirement Obligation.

The Company's non-derivative financial instruments include cash and cash equivalents, accounts receivable, accounts payable, the Convertible Notes and the Credit Facility. The carrying amount of cash and cash equivalents, accounts receivable and accounts payable approximate fair value because of their immediate or short-term maturities. The book value of the Credit Facility approximates fair value because of its floating rate structure. The Company estimated the fair value of the Convertible Notes to be approximately $160.0 million at September 30, 2014 based on observed prices for the same or similar types of debt instruments. The Company has classified the valuations of the Convertible Notes and Credit Facility under Level 2 of the fair value hierarchy.

NOTE 12 DERIVATIVE INSTRUMENTS AND PRICE RISK MANAGEMENT

<u>Commodity</u>

The Company utilizes oil swap contracts to (i) reduce the effects of volatility in price changes on the oil commodities it produces and sells, (ii) reduce commodity price risk and (iii) provide a base level of cash flow in order to assure it can execute at least a portion of its capital spending.

All derivative positions are carried at their fair value on the condensed consolidated balance sheet and are marked-to-market at the end of each period.

The Company has a master netting agreement on each of the individual oil contracts. Therefore, the current asset and liability are netted on the consolidated balance sheet, and the non-current asset and liability are netted on the condensed consolidated balance sheet.

The following table reflects open commodity swap contracts as of September 30, 2014, the associated volumes and the corresponding weighted average NYMEX reference price:

Settlement Period

	Oil (Bbls)	Fixed Price Range
Oil Swaps		
October 1, 2014 – December 31, 2014	29,468	$90.00 – 93.00
October 1, 2014 – December 31, 2014	21,600	93.01 – 96.00
October 1, 2014 – December 31, 2014	251,985	96.01 – 99.00
October 1, 2014 – December 31, 2014	82,612	99.01 – 102.00
2014 Total/Average	385,665	$97.16
January 1, 2015 – April 30, 2015	18,876	$90.00 – 93.00
January 1, 2015 – April 30, 2015	93,100	93.01 – 96.00
January 1, 2015 – April 30, 2015	341,251	96.01 – 99.00
2015 Total/Average	453,227	$96.24

The following table sets forth a reconciliation of the changes in fair value of the Company's commodity derivatives for the three and nine months ended September 30, 2014 and 2013.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Beginning fair value of commodity derivatives	$ (5,852,801)	$ 49,266	$ (853,005)	$ (181,248)
Total gains (losses) on commodity derivatives	11,184,716	(2,720,160)	3,722,780	(2,822,427)
Cash settlements paid on commodity derivatives	313,451	1,264,820	2,775,591	1,597,601
Ending fair value of commodity derivatives	$ 5,645,366	$ (1,406,074)	$ 5,645,366	$ (1,406,074)

The use of derivative transactions involves the risk that the counterparties will be unable to meet the financial terms of such transactions. The Company has netting arrangements with Wells Fargo that provide for offsetting payables against receivables from separate derivative instruments.

Warrant Liability

The warrants issued to White Deer Energy pursuant to the Securities Purchase Agreement are classified as liabilities on the consolidated balance sheets because the warrants contain a contingent put and other liability type provisions (see Note 5 – Preferred and Common Stock). The shares underlying the warrants are contingently redeemable and are subject to remeasurement at each balance sheet date, and any changes in fair value will be recognized as a component of other (expense) income on the accompanying consolidated statements of operations.

The Company estimated the value of the warrants issued with the Securities Purchase Agreement on the date of issuance to be $8,626,000, or $1.69 per warrant, using the Monte Carlo model with the following assumptions: a term of 1,798 trading days, exercise price of $5.77, volatility rate of 40%, and a risk-free interest rate of 1.38%. The Company remeasured the warrants as of September 30, 2014, using the following assumptions: a term of 1,316 trading days, exercise price of $5.77, a 15-day volume weighted average stock price of $6.96, volatility rate of 45%, and a risk-free interest rate of 2.5%. As of September 30, 2014, the fair value of the warrants was $17,454,000, and was recorded as a liability on the accompanying consolidated balance sheets. An increase in any of the variables would cause an increase in the fair value of the warrants. Likewise, a decrease in any variable would cause a decrease in the value of the warrants.

NOTE 13 COMMITMENTS AND CONTINGENCIES

The Company may be subject to litigation claims and governmental and regulatory proceedings from time to time arising in the ordinary course of business. These claims and proceedings are subject to uncertainties inherent in any litigation or proceedings. However, the Company believes that all such litigation matters and proceedings arising in the ordinary course of business are not likely to have a material adverse effect on the Company's financial position, cash flows or results of operations.

NOTE 14 SUBSEQUENT EVENTS

Derivative Instruments

On October 3, 2014, the Company partially settled outstanding NYMEX West Texas Intermediate oil derivative swap contracts on a total of 396,000 barrels of oil, resulting in an estimated cash settlement received of $3,499,880, as indicated below:

Settlement Period	Oil (Bbls)	Settlement Price	Cover Price	Estimated Cash Settlement
October 1, 2014 – October 31, 2014	64,000	$ 97.33	$ 89.89	$476,160
November 1, 2014 – November 30, 2014	64,000	97.18	88.86	532,480
December 1, 2014 – December 31, 2014	64,000	96.96	88.05	570,240
January 1, 2015 – January 31, 2015	68,000	95.99	87.15	601,120
February 1, 2015 – February 28, 2015	68,000	95.92	86.70	626,960
March 1, 2015 – March 31, 2015	68,000	96.49	86.30	692,920
Total	396,000	$ 96.63	$ 87.79	$3,499,880

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS.

The following discussion and analysis of our financial condition and results of operations should be read together with our financial statements appearing in this Form 10-Q. This discussion contains forward-looking statements that involve risks and uncertainties because they are based on current expectations and relate to future events and future financial performance. Our actual results may differ materially from those anticipated in these forward-looking statements as a result of many important factors, including those set forth in Part II, Item 1A of this Form 10-Q, in our Annual Report on Form 10-K for the year ended December 31, 2013 and in our Quarterly Reports on Form 10-Q for the quarter ended March 31, 2014 and June 30, 2014 under the heading "Risk Factors".

Overview

Emerald Oil, Inc., a Delaware corporation ("Emerald," the "Company," "we," "us," or "our"), is a Denver-based independent exploration and production company that is focused on developing wells and acquiring acreage in the Williston Basin of North Dakota and Montana. We believe the location, size and concentration of our acreage in our core project areas create an opportunity for us to achieve cost, recovery and production efficiencies through the large-scale development of our project inventory.

Our Williston Basin acreage is located primarily in McKenzie, Billings and Stark Counties of North Dakota and Richland County of Montana. Our primary geologic targets are the Bakken Pool where our primary objectives are the dolomitic, sandy interval between the two Bakken Shales at an approximate vertical depth of 10,600 to 11,300 feet and the Three Forks that is present immediately below the lower Bakken Shale. We also target the Pronghorn Sand formation, located primarily in Billings and Stark Counties of North Dakota and run along the Bakken shale pinch-out in the Southern Williston Basin. Our operations are in an area that we believe has high reservoir pressure and a high degree of thermal maturity, which is prospective for both the Middle Bakken and multiple benches within the Three Forks. We currently operate a three-rig drilling program, with plans to move to a two-rig drilling program at the end of the first quarter of 2015.

Summary of operating and financial results for the three months ended September 30, 2014:

- Production volumes totaled 351,755 Boe for the third quarter of 2014, compared to 172,678 Boe for the third quarter of 2013, an increase of 103.7%.
- Oil, natural gas and natural gas liquid sales in the third quarter of 2014 were $28.7 million compared to $17.3 million for the third quarter of 2013.

- Net income was $13.7 million for the third quarter of 2014, compared to a net loss of $5.7 million for the third quarter of 2013.
- We spud 9 gross (7.9 net) operated wells and completed 10 gross (7.5 net) operated wells during the third quarter of 2014.

Summary of operating and financial results for the nine months ended September 30, 2014:

- Production volumes totaled 917,980 Boe for the first nine months of 2014 compared to 395,272 Boe for the first nine months of 2013, an increase of 132.2%.
- Oil, natural gas and natural gas liquid sales in the first nine months of 2014 were $79.1 million compared to $36.1 million for the first nine months of 2013.
- Net income was $10.1 million for the first nine months of 2014, compared to a net loss of $20.2 million for the first nine months of 2013.
- Cash flow provided by operating activities was $31.0 million for the first nine months of 2014, compared to $9.5 million for the first nine months of 2013.
- We spud 27 gross (21.3 net) operated wells and completed 15 gross (11.2 net) operated wells during the first nine months of 2014.

Recent Developments

Acreage Acquisitions and Divestitures

On September 2, 2014 we acquired approximately 30,500 net acres located in McKenzie, Billings and Dunn Counties of North Dakota from an unrelated third party. The total consideration paid was approximately $71.2 million in cash and the assignment of approximately 4,300 net acres located in Williams County, North Dakota. Net daily production from the acquired acreage was approximately 400 Boe/day as of May 1, 2014, the effective date of the transaction. The acquisition increased our interest in 12 existing operated designated spacing units (“DSUs”) in our Low Rider area, added six potentially operated DSUs in our Low Rider area, increased our working interest in one existing operated DSU in our Lewis & Clark area and added 17 potentially operated DSUs in our Lewis & Clark area, while divesting our acreage position in our Easy Rider area. We did not have any production associated with the approximate 4,300 acres assigned as part of the purchase price consideration.

Finance Update

In conjunction with the acquisition discussed above, the borrowing base under our credit facility increased from $100 million to $200 million. The redetermined borrowing base shall remain in effect until the earlier of (i) the next scheduled redetermination date or (ii) the date the borrowing base is otherwise adjusted pursuant to the terms of the credit facility. The other terms of the credit facility remained unchanged.

Assets and Acreage Holdings

As of September 30, 2014, we held approximately 121,000 net acres in the Williston Basin. We operate approximately 91,000 net acres, or 75% of our total net acreage.

Our acreage holdings are comprised of the operating areas below:

- 72,000 net acres in the Low Rider area of McKenzie County, North Dakota;
- 8,000 net acres in the Richland area of Richland County, Montana;
- 6,000 net acres in the Pronghorn Sand formation in Stark and Billings Counties, North Dakota in the core of the Pronghorn field; and
- 35,000 net acres in the Lewis & Clark area of McKenzie County, North Dakota south of the Low Rider area.

2014 Capital Development Plan

Our operated drilling program creates higher rate of return opportunities while allowing us to control the deployment of our capital development budget. We expect to fund the remainder of our current 2014 capital expenditure budget using cash on hand, cash flow from operations and borrowings under our revolving credit facility. We may consider funding growth opportunities beyond our current 2014 capital expenditure budget with future capital markets activity if we believe the transaction to be accretive to our stockholders.

Our future financial results will depend primarily on: (i) the ability to fully implement our exploration and development program, which is dependent on the availability of capital resources; (ii) the ability to continue to source and evaluate potential projects; (iii) the ability to discover commercial quantities of oil and natural gas; and (iv) the market price for oil and natural gas. There can be no assurance that we will be successful in any of these respects, that the prices of oil and natural gas prevailing at the time of production will be at a level allowing for profitable production, or that we will be able to obtain additional funding, if necessary. See Item 1A. Risk Factors.

We added a third high specification drilling rig in March 2014 to accelerate development of our Williston Basin operated leasehold. For the 12-month period ending December 31, 2014, we plan to spend approximately $250.0 million to drill 25.2 net operated wells in the Williston Basin. We had incurred $199.8 million in drilling and completion costs in our operated well program through September 30, 2014. We had budgeted approximately $150.0 million in 2014 to increase our working interests in our core operated areas along with continuing to grow our overall operated acreage position in the Williston Basin. The land acquisition budget was increased to $200 million for 2014 following the acquisition of approximately 30,500 net acres in North Dakota in September 2014 as described under Item 2. - *Recent Developments – Acreage Acquisitions and Divestitures* above. We had incurred $171.6 million toward our acquisition budget through September 30, 2014, and we do not anticipate reaching or exceeding the acquisition budget of $200 million through the remainder of 2014.

The Low Rider area, which is our core operated area, consists of approximately 72,000 net acres that are primarily located in McKenzie County, North Dakota. Our average working interest in our operated wells in the Low Rider area as of September 30, 2014 was approximately 74%, and we continue to work toward increasing our average working interest in the area. As of September 30, 2014, we had approximately 36 gross (26.6 net) producing operated wells in the Williston Basin, excluding producing wells included in acreage acquisitions in 2013 and the first nine months of 2014 developed outside of our operated well program. We had 18 gross (14.6 net) operated Bakken and Three Forks wells that were in the process of being drilled, awaiting completion, in the process of completion or awaiting flow back subsequent to fracture stimulation as of September 30, 2014. As of September 30, 2014, we were running a two-rig horizontal development program in the Low Rider area. Our third rig commenced operations during the second quarter of 2014 targeting the Easy Rider and Pronghorn Sand operating areas.

2015 Capital Development Plan

We plan to move to a two-rig operated drilling program at the close of the first quarter 2015. If commodity prices improve before the end of the first quarter 2015, we will reevaluate the development plan, rig count and acreage acquisition opportunities. Based upon a 2.25 rig budget for the calendar year 2015, we plan to spend approximately $225 million to drill 23.5 net operated wells in the Williston Basin. We previously budgeted $50 million in land acquisitions during 2015, but because of our substantial acreage position and the current price of crude oil we will likely spend $20 million or less on land acquisitions during the calendar year 2015. Our 2015 exploration and development program will focus on holding by production undeveloped leasehold in McKenzie County, North Dakota and Richland County, Montana.

Productive Wells

The following table summarizes gross and net productive operated and non-operated oil wells at September 30, 2014 and September 30, 2013. A net well represents our fractional working ownership interest of a gross well. The following table does not include 18 gross (14.6 net) operated Bakken and Three Forks wells and 4 gross (1.84 net) non-operated Bakken wells that were in the process of being drilled, awaiting completion, in the process of completion or awaiting flow back subsequent to fracture stimulation as of September 30, 2014, and it does not include 6 gross (3.46 net) operated Bakken and Three Forks wells and 5 gross (0.90 net) non-operated Bakken wells that were in the process of being drilled, awaiting completion, in the process of completion or awaiting flow back subsequent to fracture stimulation as of September 30, 2013.

	September 30,			
	2014		2013	
	Gross	Net	Gross	Net
North Dakota Bakken and Three Forks – operated	36	26.6	8	6.1

North Dakota acquired production – operated[1]	43	33.5	11	7.6
North Dakota Bakken and Three Forks – non-operated	40	3.6	8	0.8
Montana Bakken and Three Forks – non-operated	—	—	—	—
Total	119	63.7	27	14.5

(1) 11 gross (7.85 net) vertical wells relate to producing properties included within an acreage acquisition completed on August 2, 2013. The wells are producing from the Birdbear, Duperow and Red River formations. 10 gross (7.17 net) wells relate to producing properties included within an acquisition completed on February 13, 2014 and the wells are producing from the Bakken formation. 22 gross (19.9 net) wells relate to producing properties included within the acquisition completed on September 2, 2014 and the wells are producing from the Bakken formation. Operatorship was transferred to us upon closing of all acquisitions.

Results of Operations

Comparison of the Three Months Ended September 30, 2014 with the Three Months Ended September 30, 2013

	Three Months Ended September 30,	
	2014	2013
REVENUES		
Oil Sales	$28,266,332	$16,952,644
Natural Gas Sales	460,857	363,914
Net Gains (Losses) on Commodity Derivatives	11,184,716	(2,720,160)
Total Revenues	39,911,905	14,596,398
OPERATING EXPENSES		
Lease Operating Expenses	4,466,391	1,922,744
Workover Expenses	2,496,059	164,891
Total Production Expenses	6,962,450	2,087,635
Production Taxes	3,142,998	1,879,160
General and Administrative Expenses, Excluding Non-Cash Share-Based Compensation	2,665,494	2,021,680
Non-Cash Share-Based Compensation	2,818,161	4,172,522
Total General & Administrative	5,483,655	6,194,202
Depletion of Oil and Natural Gas Properties	9,193,566	4,497,002
Depreciation and Amortization	104,465	40,631
Accretion of Discount on Asset Retirement Obligations	28,037	7,502
Gain on Sale of Oil and Natural Gas Properties	—	(8,892,344)
Total Operating Expenses	24,915,171	5,813,788
INCOME FROM OPERATIONS	14,996,734	8,782,610
OTHER EXPENSE, NET	(1,337,659)	(524,105)
INCOME BEFORE INCOME TAXES	13,659,075	8,258,505
INCOME TAX EXPENSE	—	—
NET INCOME	13,659,075	8,258,505
Less: Preferred Stock Dividends and Deemed Dividends	—	(13,997,089)
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCKHOLDERS	$13,659,075	$(5,738,584)

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The following tables sets forth selected operating data for the periods indicated. Production volumes and average sales prices are derived from accrued accounting data for the relevant period indicated.

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013
Net Oil and Natural Gas Revenues:		
Oil	$ 28,266,332	$ 16,952,944
Natural Gas and Other Liquids	460,857	363,914
Total Oil and Natural Gas Sales	28,727,189	17,316,558
Net Gains (Losses) on Commodity Derivatives	11,184,716	(2,720,160)
Total Revenues	39,911,905	14,596,398
Oil Derivative Net Cash Settlements Paid	313,451	1,264,755
Net Production:		
Oil (Bbl)	338,352	164,570
Natural Gas and Other Liquids (Mcf)	80,417	48,648
Barrel of Oil Equivalent (Boe)	351,755	172,678
Average Sales Prices:		
Oil (per Bbl)	$ 83.54	$ 103.01
Effect of Settled Oil Derivatives on Average Price (per Bbl)	(0.93)	(7.69)
Oil Net of Settled Derivatives (per Bbl)	$ 82.61	$ 95.32
Natural Gas and Other Liquids (per Mcf)	$ 5.73	$ 7.48
Barrel of Oil Equivalent with Net Cash Settlements Paid on Commodity Derivatives (per Boe)	$ 80.78	$ 92.96

Production costs incurred, presented on a per Boe basis, for the three months ended September 30, 2014 and 2013 are summarized in the following table:

	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013
Costs and Expenses Per Boe of Production:		
Lease Operating Expenses	$ 12.70	$ 11.13
Workover Expenses	7.10	0.95
Total Production Expenses	19.80	12.09
Production Taxes	8.94	10.88
General and Administrative, Excluding Non-Cash Share-Based Compensation	7.58	11.71
Non-Cash Shared-Based Compensation	8.01	24.16
Total General and Administrative	15.59	35.87

Depletion of Oil and Natural Gas Properties	26.14	26.04
Depreciation and Amortization	0.30	0.24
Accretion of Discount on Asset Retirement Obligation	0.08	0.04

Revenues

Revenues from sales of oil and natural gas were $28.7 million for the third quarter of 2014 compared to $17.3 million for the third quarter of 2013. Our total production volumes on a Boe basis increased 103.7% from 172,678 Boe to 351,755 Boe in the third quarter of 2014 as compared to the third quarter of 2013. Production primarily increased due to the addition of 30.75 net productive operated Bakken/Three Forks wells since October 1, 2013, offset by the sale of 9.13 net productive non-operated wells in the Williston Basin in 2013. During the third quarter of 2014, we realized an $82.61 average price per Bbl of oil (including settled derivatives) compared to a $95.32 average price per Bbl of oil during the third quarter of 2013.

Net Gains (Losses) on Commodity Derivatives

Net gains on commodity derivatives were $11,184,716 during the third quarter of 2014 compared to a loss of $2,720,160 in the third quarter of 2013. Net cash settlements paid on commodity derivatives were $313,451 in the third quarter of 2014 compared to $1,264,755 in the third quarter of 2013. Our derivatives are not designated for hedge accounting and are accounted for using the mark-to-market accounting method whereby gains and losses from changes in the fair value of derivative instruments are recognized immediately into earnings. Mark-to-market accounting treatment creates volatility in our revenues as unsettled gains and losses from derivatives are included in total revenues and are not included in accumulated other comprehensive income in the accompanying balance sheets. As commodity prices increase or decrease, such changes will have an opposite effect on the mark-to-market value of our derivatives. Future derivatives gains will be offset by lower future wellhead revenues. Conversely, future derivatives losses will be offset by higher future wellhead revenues based on the value at the settlement date. At September 30, 2014 and September 30, 2013, all of our derivative contracts were recorded at their fair value, which was a net asset of $5,645,366, and a net liability of $1,406,074, respectively.

Production Expenses

Production expenses were $6,962,450 for the third quarter of 2014 compared to $2,087,635 for the third quarter of 2013. Non-recurring workover expenses totaling $2,496,060 were incurred during the third quarter of 2014 compared to $164,891 for the third quarter of 2013. A portion of the increase in workover expense was attributable to producing properties acquired during 2014. On a per unit basis, production expenses increased from $12.09 per Boe in the third quarter of 2013 compared to $19.80 per Boe for the third quarter of 2014 and $12.70 per Boe for the third quarter of 2014 when excluding workover costs. We experience increases in production expenses as we add new wells and maintain production from existing properties. The use of power generators and associated fuel costs, the disposal of produced water and pump repairs and replacement are large cost drivers in our Williston Basin wells.

Production Taxes

Production taxes were $3,142,998 for the third quarter of 2014 compared to $1,879,160 for the third quarter of 2013. We pay production taxes based on realized oil and natural gas sales. Our average production tax rates were 10.9% for the third quarter of 2014 and 2013. Certain portions of our production occur in North Dakota and Montana jurisdictions that have lower initial tax rates for an established period of time or until an established threshold of production is exceeded, after which the tax rates are increased to the standard tax rate of 11.5%.

General and Administrative Expense

General and administrative expenses were $5,483,655 during the third quarter of 2014 compared to $6,194,202 during the third quarter of 2013. The decrease of $710,547 during the third quarter of 2014 is attributable to a decrease of $1,246,724 related to share-based compensation expense and employee cash compensation and related expenses, offset by an increase of $179,022 related to insurance expense and an increase of $338,569 related to non-recurring consulting expenses.

Depletion Expense

Our depletion expense is driven by many factors, including certain exploration costs involved in the development of producing reserves, production levels and estimates of proved reserve quantities and future developmental costs. Depletion expense was $9,193,566 during the third quarter of 2014 compared to $4,497,002 during the third quarter of 2013. On a per-unit basis, depletion expense was $26.14 per Boe during the third quarter of 2014 compared to $26.04 per Boe during the third quarter of 2013. Our depletion expense is based on the capitalized costs related to properties having proved reserves, plus the estimated future development costs and asset retirement costs which are depleted and amortized on the unit-of-production method based on the estimated gross proved reserves determined by our petroleum engineers. This increase in depletion expense during the third quarter of 2014 was due primarily to the addition of 30.75 net productive operated Bakken/Three Forks wells since October 1, 2013, offset by the sale of 9.13 net productive non-operated wells in the Williston Basin in 2013.

Other Expense, Net

Other expense, net was $1,337,659 for the third quarter of 2014 compared to $524,105 for the third quarter of 2013. We recognized warrant revaluation income of $216,000 on the warrant liability for the third quarter of 2014 compared to warrant revaluation expense of $506,000 for the third quarter of 2013. Our warrant liability is accounted for using the mark-to-market accounting method whereby changes from the prior period in the fair value of derivative instruments are recognized immediately into earnings. Interest expense was $1,206,571 for the third quarter of 2014, compared to $21,437 for the third quarter of 2013. This increase in interest expense during the third quarter of 2014 was primarily related to the Convertible Notes issued in March 2014 and outstanding at September 30, 2014.

Net Income (Loss) Attributable to Common Stockholders

We had net income attributable to common stockholders of $13,659,075 for the third quarter of 2014 compared to a net loss attributable to common stockholders of $5,738,584 for the third quarter of 2013 (representing $0.21 and $(0.13) per share-basic, respectively). The change in net income (loss) attributable to common stockholders in our period-over-period results was driven by increased revenue and production from our oil and natural gas properties and commodity derivative gains and the absence of preferred stock dividends in 2014, partially offset by higher operating expenses and the gain on sale of oil and natural gas properties recognized in 2013.

Comparison of the Nine Months Ended September 30, 2014 with the Nine Months Ended September 30, 2013

	Nine Months Ended September 30, 2014	2013
REVENUES		
Oil Sales	$76,989,268	$35,287,288
Natural Gas Sales	2,061,201	821,069
Net Gains (Losses) on Commodity Derivatives	3,722,780	(2,822,427)
Total Revenues	82,773,249	33,285,930
OPERATING EXPENSES		
Lease Operating Expenses	10,448,091	4,366,572
Workover Expenses	3,029,085	356,948
Total Production Expenses	13,477,176	4,723,520
Production Taxes	8,632,608	3,629,557
General and Administrative Expenses, Excluding Non-Cash Share-Based Compensation	12,112,174	11,024,436
Non-Cash Share-Based Compensation	9,497,044	6,538,318
Total General and Administrative	21,609,218	17,562,754
Depletion of Oil and Natural Gas Properties	24,071,676	11,238,783
Depreciation and Amortization	251,722	94,665
Accretion of Discount on Asset Retirement Obligations	63,837	21,564
Gain on Sale of Oil and Natural Gas Properties	—	(8,892,344)
Total Operating Expenses	68,106,237	28,378,499
INCOME FROM OPERATIONS	14,667,012	4,907,431
OTHER EXPENSE, NET	(4,609,075)	(4,856,883)
INCOME BEFORE INCOME TAXES	10,057,937	50,548
INCOME TAX EXPENSE	—	—
NET INCOME	10,057,937	50,548
Less: Preferred Stock Dividends and Deemed Dividends	—	(20,279,197)
NET INCOME (LOSS) ATTRIBUTABLE TO COMMON STOCKHOLDERS	$10,057,937	$(20,228,649)

The following tables sets forth selected operating data for the periods indicated. Production volumes and average sales prices are derived from accrued accounting data for the relevant period indicated.

	Nine Months Ended September 30,	
	2014	2013
Net Oil and Natural Gas Revenues:		
Oil	$76,989,268	$35,287,288
Natural Gas and Other Liquids	2,061,201	821,069
Total Oil and Natural Gas Sales	79,050,469	36,108,357
Net Gains (Losses) on Commodity Derivatives	3,722,780	(2,822,427)
Total Revenues	82,773,249	33,285,930
Oil Derivative Net Cash Settlements Paid	2,775,591	1,597,536
Net Production:		
Oil (Bbl)	876,947	373,048
Natural Gas and Other Liquids (Mcf)	246,195	133,343
Barrel of Oil Equivalent (Boe)	917,980	395,272
Average Sales Prices:		
Oil (per Bbl)	$87.79	$94.59
Effect of Settled Oil Derivatives on Average Price (per Bbl)	(3.17)	(4.28)
Oil Net of Settled Derivatives (per Bbl)	$84.62	$90.31
Natural Gas and Other Liquids (per Mcf)	$8.37	$6.16
Barrel of Oil Equivalent with Net Cash Settlements Paid on Commodity Derivatives (per Boe)	$83.09	$87.31

Production costs incurred, presented on a per Boe basis, for the nine months ended September 30, 2014 and 2013 are summarized in the following table:

	Nine Months Ended September 30,	
	2014	2013
Costs and Expenses Per Boe of Production:		
Lease Operating Expenses	$ 11.38	$ 11.05
Workover Expenses	3.30	0.90
Total Production Expenses	14.68	11.95
Production Taxes	9.40	9.18
General and Administrative Expenses, Excluding Non-Cash Share-Based Compensation	13.19	27.89
Non-Cash Shared-Based Compensation	10.35	16.54
Total General and Administrative Expenses	23.54	44.43
Depletion of Oil and Natural Gas Properties	26.22	28.43
Depreciation and Amortization	0.27	0.24
Accretion of Discount on Asset Retirement Obligation	0.07	0.05

Revenues

Revenues from sales of oil and natural gas were $79.1 million for the first nine months of 2014 compared to $36.1 million for the first nine months of 2013. Our total production volumes on a Boe basis increased 132.2% from 395,272 Boe to 917,980 Boe in the first nine months of 2014 as compared to the first nine months of 2013. Production primarily increased due to the addition of 30.75 net productive operated Bakken/Three Forks wells since October 1, 2013, offset by the sale of 9.13 net productive non-operated wells in the Williston Basin in 2013. During the first nine months of 2014, we realized an $84.62 average price per Bbl of oil (including settled derivatives) compared to a $90.31 average price per Bbl of oil during the first nine months of 2013.

Net Losses on Commodity Derivatives

Net gain on commodity derivatives were $3,722,780 during the first nine months of 2014 compared to a loss of $2,822,427 in the first nine months of 2013. Net cash settlements paid on commodity derivatives were $2,775,591 in the first nine months of 2014 compared to $1,597,536 in the first nine months of 2013. During the first nine months of 2014, we added swap contracts for 1,221,063 Bbls of oil at an average fixed price of $97.12 NYMEX West Texas Intermediate. Our derivatives are not designated for hedge accounting and are accounted for using the mark-to-market accounting method whereby gains and losses from changes in the fair value of derivative instruments are recognized immediately into earnings. Mark-to-market accounting treatment creates volatility in our revenues as unsettled gains and losses from derivatives are included in total revenues and are not included in accumulated other comprehensive income in the accompanying balance sheets. As commodity prices increase or decrease, such changes will have an opposite effect on the mark-to-market value of our derivatives. Future derivatives gains will be offset by lower future wellhead revenues. Conversely, future derivatives losses will be offset by higher future wellhead revenues based on the value at the settlement date. At September 30, 2014 and September 30, 2013, all of our derivative contracts were recorded at their fair value, which was a net asset of $5,645,366, and a net liability of $1,406,074, respectively.

Production Expenses

Production expenses were $13,477,176 for the first nine months of 2014 compared to $4,723,520 for the first nine months of 2013. Non-recurring workover expenses totaling $3,029,085 were incurred during the first nine months of 2014 compared to $356,948 for the first nine months of 2013. A portion of the increase in workover expense was attributable to producing properties acquired during 2013 and 2014. On a per unit basis, production expenses increased from $11.95 per BOE in the first nine months of 2013 to $14.68 per Boe for the first nine months of 2014 and $11.38 per Boe for the first nine months of 2014 when excluding workover costs. We experience increases in production expenses as we add new wells and maintain production from existing properties. The use of power generators and associated fuel costs, the disposal of produced water and pump repairs and replacement are large cost drivers in our Williston Basin wells.

Production Taxes

Production taxes were $8,632,608 for the first nine months of 2014 compared to $3,629,557 for the first nine months of 2013. We pay production taxes based on realized oil and natural gas sales. Our average production tax rates were 10.9% for the first nine months of 2014 compared to 10.1% for the first nine months of 2013. Certain portions of our production occur in North Dakota and Montana jurisdictions that have lower initial tax rates for an established period of time or until an established threshold of production is exceeded, after which the tax rates are increased to the standard tax rate of 11.5%. The 2014 average production tax rate was higher than 2013 due to expirations of production tax holidays during the year and the disposition of non-operated wells in jurisdictions that had lower initial tax rates.

General and Administrative Expense

General and administrative expenses were $21,609,218 during the first nine months of 2014 compared to $17,562,754 during the first nine months of 2013. The increase of $4,046,464 was due to increases in personnel and infrastructure to accelerate our operated well program in the Williston Basin. Specifically, during the first nine months of 2014 an increase of $3,461,292 was related to share-based compensation expense and employee cash compensation and related expenses, an increase of $432,942 related to non-recurring consulting expenses, and an increase of $153,369 related to software expense.

Depletion Expense

Our depletion expense is driven by many factors, including certain exploration costs involved in the development of producing reserves, production levels and estimates of proved reserve quantities and future developmental costs. Depletion expense was $24,071,676 during the first nine months of 2014 compared to $11,238,783 during the first nine months of 2013. On a per-unit basis, depletion expense was $26.22 per Boe during the first nine months of 2014 compared to $28.43 per Boe during the first nine months of 2013. Our depletion expense is based on the capitalized costs related to properties having proved reserves, plus the estimated future development costs and asset retirement costs which are depleted and amortized on the unit-of-production method based on the estimated gross proved reserves determined by our petroleum engineers. This increase in depletion expense during the first nine months of 2014 was due primarily to the addition of 30.75 net productive operated Bakken/Three Forks wells since October 1, 2013, offset by the sale of 9.13 net productive non-operated wells in the Williston Basin in 2013.

Other Expense, Net

Other expense, net was $4,609,075 for the first nine months of 2014 compared to $4,856,883 for the first nine months of 2013. We recognized warrant revaluation expense of $1,751,000 on the warrant liability for the first nine months of 2014 compared to warrant revaluation expense of $4,587,000 for the first nine months of 2013. Our warrant liability is accounted for using the mark-to-market accounting method whereby changes from the prior period in the fair value of derivative instruments are recognized immediately into earnings. Interest expense was $2,515,034 for the first nine months of 2014, compared to $276,113 for the first nine months of 2013. This increase in interest expense was primarily related to the Convertible Notes issued in March 2014 and outstanding at September 30, 2014.

Net Income (Loss) Attributable to Common Stockholders

We had net income attributable to common stockholders of $10,057,937 for the first nine months of 2014 compared to a net loss attributable to common stockholders of $20,288,649 for the first nine months of 2013 (representing $0.15 and $(0.60) per share-basic, respectively). The change in net income (loss) attributable to common stockholders in our period-over-period results was driven by increased revenue and production from our oil and natural gas properties and commodity derivative gains and the absence of preferred stock dividends in 2014, partially offset by higher operating expenses and the gain on sale of oil and natural gas properties recognized in 2013.

Non-GAAP Financial Measures

Adjusted EBITDA

In addition to reporting net income (loss) as defined under GAAP, we also present net earnings before interest, income taxes, preferred stock dividends, depletion, depreciation and amortization, impairment of oil and natural gas properties, accretion of discount on asset retirement obligations, gains and losses on acquisitions and divestitures, net gain (loss) from mark-to-market on commodity derivatives, mark-to-market on our warrant liability and non-cash expenses relating to stock-based compensation recognized under ASC Topic 718 (“Adjusted EBITDA”), which is a non-GAAP performance measure. Adjusted EBITDA consists of net earnings after adjustment for those items described in the table below. Adjusted EBITDA does not represent, and should not be considered an alternative to GAAP measurements, such as net income (loss) (its most directly comparable GAAP measure), and our calculations thereof may not be comparable to similarly titled measures reported by other companies. By eliminating the items described below, we believe the measure is useful in evaluating our fundamental core operating performance. We also believe that Adjusted EBITDA is useful to investors because similar measures are frequently used by securities analysts, investors, and other interested parties in their evaluation of companies in similar industries. Our management uses Adjusted EBITDA to manage our business, including in preparing our annual operating budget and financial projections. Our management does not view Adjusted EBITDA in isolation and also uses other measurements, such as net income (loss) and revenues to measure operating performance. The following table provides a reconciliation of net income (loss) to Adjusted EBITDA for the periods presented:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2014	2013	2014	2013
Net income	$ 13,659,075	$ 8,258,505	$ 10,057,937	$ 50,548
Less: Preferred stock dividends and deemed dividends	—	(13,997,089)	—	(20,279,197)
Net income (loss) attributable to common stockholders	13,659,075	(5,738,584)	10,057,937	(20,228,649)

Add: Interest expense	1,206,571	21,437	2,515,034	276,113
Accretion of discount on asset retirement obligations	28,037	7,502	63,837	21,564
Depletion, depreciation and amortization	9,298,031	4,537,633	24,323,398	11,333,448
Stock-based compensation	2,818,161	4,172,522	9,497,044	6,538,318
Warrant revaluation expense	—	506,000	1,751,000	4,587,000
Preferred stock dividends	—	764,383	—	2,582,191
Preferred stock redemption premium	—	4,375,000	—	6,250,000
Accretion of preferred stock issuance discount	—	8,857,706	—	11,447,006
Net losses on commodity derivatives	—	2,720,160	—	2,822,427
Less: Net cash settlements paid on commodity derivatives	(313,451)	(1,264,755)	(2,775,591)	(1,597,536)
Net gains on commodity derivatives	(11,184,716)	—	(3,722,780)	—
Gain on sale of oil and natural gas properties	—	(8,892,344)	—	(8,892,344)
Warrant revaluation income	(216,000)	—	—	
Adjusted EBITDA	$ 15,295,708	$ 10,066,660	$ 41,709,879	$ 15,139,538

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Liquidity and Capital Resources

Liquidity is a measure of a company's ability to meet potential cash requirements. We have historically met our capital requirements through the issuance of common and preferred stock, debt securities and by short-term and long-term borrowings. In the future, we anticipate we will be able to provide the necessary liquidity from our cash on hand, cash flow from operations and availability under our revolving credit facility; however, if we do not generate sufficient cash flow from operations or do not have availability under our revolving credit facility, we may attempt to continue to finance our operations through equity and/or debt financings.

The following table summarizes total current assets, total current liabilities and working capital at September 30, 2014:

Current assets	$69,200,218
Current liabilities	109,336,462
Working capital	$(40,136,244)

Private Placement

On March 24, 2014, we completed a private placement of $172.5 million in aggregate principal amount of 2.0% Convertible Notes, and entered into an indenture governing the Convertible Notes, with U.S. Bank National Association, as trustee. The Convertible Notes accrue interest at a rate of 2.00% per year, payable semiannually in arrears on April 1 and October 1 of each year, beginning on October 1, 2014. The Convertible Notes mature on April 1, 2019. The Convertible Notes are our unsecured senior obligations and are equal in right of payment to our existing and future senior indebtedness.

We have used and intend to further use the net proceeds from this offering, along with cash on hand, cash flow from operations and additional borrowings under our revolving credit facility, to fund our 2014 capital expenditure budget. Any remaining net proceeds will be used for general corporate purposes, including working capital.

Credit Facility

On November 20, 2012, we entered into a senior secured revolving credit facility (the "Credit Facility") with Wells Fargo Bank, N.A., as administrative agent ("Wells Fargo"), and the lenders party thereto. The Credit Facility is a senior secured reserve-based revolving credit facility with a maximum commitment of $400 million. As of September 30, 2014, the Credit Facility had a borrowing base of $200.0 million and $20.0 million outstanding.

Amounts borrowed under the Credit Facility will mature on September 30, 2018, and upon such date, any amounts outstanding under the Credit Facility are due and payable in full. Redeterminations of the borrowing base will be on a semi-annual basis, with an option to elect an additional redetermination every six months between the semi-annual redeterminations.

The annual interest cost, which is dependent upon the percentage of the borrowing base utilized, is, at our option, based on either the Alternate Base Rate (as defined under the terms of the Credit Facility) plus 0.75% to 1.75% or the London Interbank Offer Rate (LIBOR) plus 1.75% to 2.75%; provided, in no event may the interest exceed the maximum interest rate allowed by any current or future law. Interest on ABR Loans is due and payable on a quarterly basis, and interest on Eurodollar Loans is due and payable, at our option, at one-, two-, three-, six- (or in some cases nine- or twelve-) month intervals. We also pay a commitment fee ranging from 0.375% to 0.5%, depending on the percentage of the borrowing base utilized. As of September 30, 2014, the annual interest rate on the Credit Facility was 2.29%.

A portion of the Credit Facility not in excess of $5 million will be available for the issuance of letters of credit by Wells Fargo. We will pay a rate per annum ranging from 1.75% to 2.75% on the face amount of each letter of credit issued and will pay a fronting fee equal to the greater of $500 and 0.125% of the face amount of each letter of credit issued. As of September 30, 2014, we have not obtained any letters of credit under the existing facility.

Each of our subsidiaries is a guarantor under the Credit Facility. The Wells Fargo Facility is secured by first priority, perfected liens and security interests on substantially all of our assets and our guarantors, including a pledge of their ownership in their respective subsidiaries.

The Credit Facility contains customary covenants that include, among other things: limitations on our ability to incur or guarantee additional indebtedness; create liens; pay dividends on or repurchase stock; make certain types of investments; enter into transactions with affiliates; and sell assets or merge with other companies. The Credit Facility also requires compliance with certain financial covenants, including, (a) a ratio of current assets to current liabilities of at least 1.00 to 1.00, (b) a maximum ratio of total debt to EBITDA for the preceding four fiscal quarters of no more than 4.00 to 1.00. For any fiscal quarter ending in calendar year 2014, total debt is reduced by cash equivalents less $10,000,000 for purposes of calculating the total debt to EBITDA ratio. We were in compliance with all covenants under the Credit Facility as of September 30, 2014.

The Credit Facility allows us to hedge up to 60% of proved reserves for the first 24 months and 80% of projected production from proved developed producing reserves from 24 months up to 60 months later provided that in no event shall the aggregate amount of hedges exceed 100% of actual production in the current period.

Satisfaction of Our Cash Obligations for the Next Twelve Months

We project we will have sufficient capital to accomplish our development plan and forecasted general and administrative expenses for the next twelve months. Our projections are based on cash on hand, increasing cash flow from operations, and increased borrowing capacity based on reserve growth. However, we may scale back our development plan should our projections of cash flow and borrowing capacity fall short of expectations or commodity prices fall substantially. We may also choose to access the equity or debt capital markets to fund acreage acquisitions and/or accelerated drilling at the discretion of management, depending on prevailing market conditions. However, there can be no assurance that any additional capital will be available to us on favorable terms or at all. We will evaluate any potential opportunities for acquisitions as they arise. Given our asset base and anticipated increasing cash flows, we believe we are in a position to take advantage of any appropriately priced acquisition opportunities that may arise.

Our prospects must be considered in light of the risks, expenses and difficulties frequently encountered by companies in their early stage of operations, particularly companies in the oil and natural gas exploration industry. Such risks include, but are not limited to, an evolving and unpredictable business model and the management of growth. To address these risks we must, among other things, implement and successfully execute our business and marketing strategy, respond to competitive developments, and attract, retain and motivate qualified personnel. There can be no assurance that we will be successful in addressing such risks, and the failure to do so can have a material adverse effect on our business prospects, financial condition and results of operations.

Effects of Inflation and Pricing

The oil and natural gas industry is cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry put extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and may not adjust downward in proportion. Material changes in prices also impact our current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, impairment assessments of oil and natural gas properties, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and natural gas companies and their ability to raise capital, borrow money and retain personnel. While we do not currently expect business costs to materially increase, higher prices for oil and natural gas could result in increases in the costs of materials, services and personnel.

Cash and Cash Equivalents

Our total cash resources as of September 30, 2014 were $12,561,188, compared to $144,255,438 as of December 31, 2013. The decrease in our cash balance was primarily attributable to acquisitions and development of oil and natural gas properties, offset by the Convertible Notes offering completed during the first quarter of 2014 and borrowings under our Credit Facility.

Net Cash Provided By Operating Activities

Net cash provided by operating activities was $30,969,057 for the nine months ended September 30, 2014 compared to $9,538,728 for the nine months ended September 30, 2013. The change in the net cash provided by operating activities is primarily attributable to higher production revenue during 2014, partially offset by higher general and administrative expenses, including employment and employment-related expenses.

Net Cash Used For Investment Activities

Net cash used in investment activities was $348,524,792 for the nine months ended September 30, 2014 compared to $27,727,799 for the nine months ended September 30, 2013. The change in net cash used in investment activities is primarily attributable to increased purchase and development of oil and natural gas properties in the Williston Basin. The change in net cash provided by investment activities for the first nine months of 2013 is offset by proceeds from the sale of oil and natural gas properties completed in September 2013.

Net Cash Provided By Financing Activities

Net cash provided by financing activities was $185,861,485 for the nine months ended September 30, 2014 compared to $77,524,600 for the nine months ended September 30, 2013. Net cash provided by financing activities for the first nine months of 2014 is primarily attributable to proceeds from the Convertible Note offering completed on March 24, 2014. Net cash provided by financing activities for the first nine months of 2013 is primarily attributable to proceeds from the preferred stock issuance completed on February 19, 2013, offset by repayment of borrowings under the Credit Facility and payment of preferred stock dividends.

Off-Balance Sheet Arrangements

We currently do not have any off-balance sheet arrangements.

Critical Accounting Policies

The preparation of financial statements in accordance with generally accepted accounting principles requires us to make estimates and judgments that affect the reported amounts of assets, liabilities, revenues and expenses. Certain of our accounting policies are considered critical, as these policies are the most important to the depiction of our financial statements and require significant, difficult or complex judgments, often employing the use of estimates about the effects of matters that are inherently uncertain. A summary of our significant accounting policies is included in *Note 2—Basis of Presentation and Significant Accounting Policies* to our consolidated financial statements included in our annual report on Form 10-K for the year ended December 31, 2013, as well as in the Management's Discussion and Analysis of Financial Condition and Results of Operations section in such Form 10-K. There have been no significant changes in the application of our critical accounting policies during the nine-month period ended September 30, 2014.

Cautionary Factors That May Affect Future Results

This Quarterly Report on Form 10-Q contains, and we may from time to time otherwise make in other public filings, press releases and presentations, forward-looking statements within the meaning of the federal securities laws. All statements other than statements of historical facts are forward-looking statements. Such statements can be identified by the use of forward-looking terminology such as "believe," "expect," "may," "should," "seek," "on-track," "plan," "project," "intend" or "anticipate," or the negative thereof or comparable terminology, or by discussions of vision, strategy or outlook, including statements related to our beliefs and intentions with respect to our growth strategy, including the amount we may invest, the location, and the scale of the drilling projects in which we intend to participate; our beliefs with respect to the potential value of drilling projects; our beliefs with regard to the impact of environmental and other regulations on our business; our beliefs with respect to the strengths of our business model; our assumptions, beliefs, and expectations with respect to future market conditions; our plans for future capital expenditures; and our capital needs, the adequacy of our capital resources, and potential sources of capital. You are cautioned that our business and operations are subject to a variety of risks and uncertainties, many of which are beyond our control and, consequently, our actual results may differ materially from those projected by any forward-looking statements. You should consider carefully the statements under the "Risk Factors" section of this report, in our Annual Report on Form 10-K for the year ended December 31, 2013, in our Quarterly Reports on Form 10-Q for the three months ended March 31, 2014 and June 30, 2014 and the other disclosures contained herein and therein, which describe factors that could cause our actual results to differ from those anticipated in the forward-looking statements, including, but not limited to, the following factors:

- our ability to diversify our operations in terms of both the nature and geographic scope of our business;
- our ability to generate sufficient cash flow from operations, borrowings or other sources to enable us to fully develop our undeveloped acreage positions;
- our ability to successfully acquire additional properties, to discover reserves, to participate in exploration opportunities and to identify and enter into commercial arrangements with customers;
- competition, including competition for acreage in resource play areas;
- our ability to retain key members of management;
- volatility in commodity prices for oil and natural gas;
- the possibility that our industry may be subject to future regulatory or legislative actions (including any additional taxes and changes in environmental regulation);
- the presence or recoverability of estimated oil and natural gas reserves and the actual future production rates and associated costs;
- the timing of and our ability to obtain financing on acceptable terms;
- interest payment requirements of our debt obligations;
- restrictions imposed by our debt instruments and compliance with our debt covenants;
- substantial impairment write-downs;
- our ability to replace oil and natural gas reserves;
- environmental risks;
- drilling and operating risks;

- exploration and development risks;

- general economic conditions, whether internationally, nationally or in the regional and local market areas in which we do business, may be less favorable than expected, including the possibility that the economic conditions in the United States will worsen and that capital markets are disrupted, which could adversely affect demand for oil and natural gas and make it difficult to access financial markets; and

- other economic, competitive, governmental, legislative, regulatory, geopolitical and technological factors that may negatively impact our business, operations or pricing.

All forward-looking statements speak only as of the date of this report and are expressly qualified in their entirety by the cautionary statements in this paragraph and elsewhere in this report. Other than as required under the securities laws, we do not assume a duty to update these forward-looking statements, whether as a result of new information, subsequent events or circumstances, changes in expectations or otherwise.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Commodity Price Risk

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile, and these markets will likely continue to be volatile in the future. The prices we receive for our production depend on numerous factors beyond our control. Our revenues during the three and nine months ended September 30, 2014 and 2013 generally have increased or decreased along with any increases or decreases in oil or natural gas prices, but the exact impact on our income is indeterminable given the variety of expenses associated with producing and selling oil and natural gas that also increase and decrease along with oil and natural gas prices.

As of September 30, 2014, our Credit Facility allowed us to enter into commodity derivative instruments, the notional volumes for which when aggregated with other commodity swap agreements and additional fixed-price physical off-take contracts then in effect, as of the date such instrument is executed, was not greater than 60% of the reasonably anticipated projected production from proved reserves. We use commodity derivative instruments as a means of managing our exposure to price changes. While we structure these derivatives to reduce our exposure to changes in price associated with the derivative commodity, they also may limit the benefit we might otherwise have received from market price increases. Based on the September 30, 2014 published commodity futures price curves for crude oil, a hypothetical price increase or decrease of $10.00 per Bbl for crude oil would increase or decrease the fair value of our net commodity derivative asset by approximately $8,000,000.

The following table reflects open commodity swap contracts as of September 30, 2014, the associated volumes and the corresponding weighted average NYMEX reference price:

Settlement Period	Oil (Bbls)	Fixed Price Range
Oil Swaps		
October 1, 2014 – December 31, 2014	29,468	$90.00 – 93.00

October 1, 2014 – December 31, 2014	21,600	93.01 – 96.00
October 1, 2014 – December 31, 2014	251,985	96.01 – 99.00
October 1, 2014 – December 31, 2014	82,612	99.01 – 102.00
2014 Total/Average	385,665	$97.16
January 1, 2015 – April 30, 2015	18,876	$90.00 – 93.00
January 1, 2015 – April 30, 2015	93,100	93.01 – 96.00
January 1, 2015 – April 30, 2015	341,251	96.01 – 99.00
2015 Total/Average	453,227	$96.24

On October 3, 2014, the Company partially settled outstanding NYMEX West Texas Intermediate oil derivative swap contracts on a total of 396,000 barrels of oil, resulting in an estimated a cash settlement received of $3,499,880.

Interest Rate Risk

As of September 30, 2014, we had an outstanding balance of $20,000,000 under our Credit Facility. Our Credit Facility subjects us to interest rate risk on borrowings. Our Credit Facility allows us to fix the interest rate of borrowings under it for all or a portion of the principal balance for a period up to six months. To the extent the interest rate is fixed, interest rate changes affect the instrument's fair market value but do not impact results of operations or cash flows. Conversely, for the portion of our borrowings that has a floating interest rate, interest rate changes will not affect the fair market value but will impact future results of operations and cash flows.

ITEM 4. CONTROLS AND PROCEDURES

We maintain disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) promulgated under the Securities Exchange Act of 1934, or the "Exchange Act") that are designed to ensure that information required to be disclosed in Exchange Act reports is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosure. Any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives.

Our management, with the participation of our Chief Executive Officer and Chief Financial Officer, has evaluated the effectiveness of the design and operation of our disclosure controls and procedures as of September 30, 2014. Based upon that evaluation and subject to the foregoing, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were effective to accomplish their objectives.

Our Chief Executive Officer and Chief Financial Officer do not expect that our disclosure controls or our internal controls will prevent all error and all fraud. The design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be considered relative to their cost. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that we have detected all of our control issues and all instances of fraud, if any. The design of any system of controls also is based partly on certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving our stated goals under all potential future conditions.

There have been no changes in our internal control over financial reporting that occurred during our most recently completed fiscal quarter that have materially affected, or are reasonably likely to materially affect, our internal controls over financial reporting.

PART II — OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We may be subject to litigation claims and governmental and regulatory proceedings arising in the ordinary course of business. These claims and proceedings are subject to uncertainties inherent in any litigation matters and proceedings. However, we believe that all such litigation matters and proceedings that may arise in the ordinary course are not likely to have a material adverse effect on our financial position, cash flows or results of operations.

ITEM 1A. RISK FACTORS

Our business is subject to a number of risks, some of which are beyond our control. In addition to the other information set forth in this report, you should carefully consider the factors discussed in Item 1A. - “Risk Factors” of our Annual Report on Form 10-K for the fiscal year ended December 31, 2013, as filed with the SEC on March 12, 2014 and Item 1A. –“Risk Factors” of our Quarterly Reports on Form 10-Q for the three months ended March 31, 2014, as filed with the SEC on May 5, 2014, and for the three months ended June 30, 2014, as filed with the SEC on August 4, 2014, that could have a material adverse effect on our business, results of operations, financial condition and/or liquidity and that could cause our operating results to vary significantly from period to period. As of September 30, 2014, there have been no material changes to the risk factors disclosed in our most recent Annual Report on Form 10-K and Quarterly Reports on Form 10-Q. Additional risks and uncertainties not currently known to us or that we currently deem to be immaterial also may materially adversely affect our business, financial condition, or operating results.

ITEM 2. UNREGISTERED SALES OR EQUITY SECURITIES AND USE OF PROCEEDS

The following table summarizes repurchases of our common stock during the three months ended September 30, 2014.

Period	Total Number of Shares Purchased [1]	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
7/1/2014 - 7/31/2014	—	$ —	—	—
8/1/2014 - 8/31/2014	9,300	8.28	—	—
9/1/2014 - 9/30/2014	85,290	7.88	—	—
Total	94,590	$ 7.92	—	—

(1) Stock repurchases during the period related to common stock received by us from employees for the payment of withholding taxes due on shares of restricted common stock issued under our equity compensation plan.

ITEM 6. EXHIBITS

The following documents are included as exhibits to this Quarterly Report on Form 10-Q. Those exhibits incorporated by reference are so indicated by the information supplied with respect thereto. Those exhibits which are not incorporated by reference are attached hereto.

3.1 Certificate of Incorporation of Emerald Oil, Inc., a Delaware corporation (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K filed on June 12, 2014, and incorporated herein by reference)

3.2 Bylaws of Emerald Oil, Inc., a Delaware corporation (filed as Exhibit 3.2 to the Company's Current Report on Form 8-K filed on June 12, 2014, and incorporated herein by reference)

10.1 First Amendment to Amended and Restated Credit Agreement, dated as of September 2, 2014, among Emerald Oil, Inc., the guarantors party thereto, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K filed on September 4, 2014, and

	incorporated herein by reference)
10.2	Purchase and Sale Agreement, dated as of August 1, 2014, between Emerald Oil, Inc., Emerald WB, LLC, Liberty Resources Management Company, LLC, Liberty Resources Bakken Operating, LLC and Liberty Resources II, LLC (filed as Exhibit 10.2 to the Company’s Quarterly Report on Form 10-Q filed on August 4, 2014, and incorporated herein by reference)
10.3	Amended and Restated Employment Agreement, effective as of September 10, 2014, between Emerald Oil, Inc. and Ryan Smith (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K filed on September 12, 2014, and incorporated herein by reference)31.1* Certification of Chief Executive Officer pursuant to Securities Exchange Act Rules 13a-15(e) and 15d-15(e) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.1*	Certification of Chief Executive Officer pursuant to Securities Exchange Act Rules 13a-15(e) and 15d-15(e) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002
31.2*	Certification of Chief Financial Officer pursuant to Securities Exchange Act Rules 13a-15(e) and 15d-15(e) as adopted pursuant to Section 302 of the Sarbanes-Oxley Act of 2002

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32.1*	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2*	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.DEF*	XBRL Definition Linkbase Document
101.LAB*	XBRL Label Linkbase Document
101.PRE*	XBRL Presentation Linkbase Document

* Attached hereto.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report on Form 10-Q to be signed on its behalf by the undersigned, thereunto duly authorized.

Dated: November 3, 2014 EMERALD OIL, INC.

/s/ *McAndrew Rudisill*
McAndrew Rudisill
Chief Executive Officer (principal executive officer)

/s/ *Ryan Smith*

Ryan Smith
Chief Financial Officer (principal financial officer)