Jones Energy, Inc.
Form 10-Q
May 09, 2014
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

(Mark One)

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

For the Quarterly Period Ended March 31, 2014

or

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

Commission file number 001-36006

Jones Energy, Inc.

(Exact name of registrant as specified in its charter)

Delaware	**1311**	**80-0907968**
(State or other Jurisdiction of Incorporation or Organization)	(Primary Standard Industrial Classification Code Number)	(IRS Employer Identification Number)

807 Las Cimas Parkway, Suite 350
Austin, Texas 78746
(512) 328-2953

(Address, including zip code, and telephone number, including area code, of Registrant s principal executive offices)

Robert J. Brooks

807 Las Cimas Parkway, Suite 350
Austin, Texas 78746
(512) 328-2953

(Address, including zip code, and telephone number, including area code, of Agent for service)

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 o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o

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 the definitions of large accelerated filer , accelerated filer , and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

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

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

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On May 1, 2014, the Registrant had 12,526,580 shares of Class A common stock outstanding and 36,836,333 shares of Class B common stock outstanding.

JONES ENERGY, INC.

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PART 1 FINANCIAL INFORMATION

Item 1. Financial Statements

Jones Energy, Inc.

Consolidated Balance Sheets (Unaudited)

(in thousands of dollars)	March 31, 2014	December 31, 2013
Assets		
Current assets		
Cash	$ 27,297	$ 23,820
Restricted Cash	67	45
Accounts receivable, net		
Oil and gas sales	80,500	51,233
Joint interest owners	58,895	42,481
Other	4,247	16,782
Commodity derivative assets	4,168	8,837
Other current assets	2,501	2,392
Deferred tax assets	12	12
Total current assets	177,687	145,602
Oil and gas properties, net, at cost under the successful efforts method	1,363,393	1,297,228
Other property, plant and equipment, net	3,472	3,444
Commodity derivative assets	20,806	25,398
Other assets	14,264	15,006
Deferred tax assets	618	1,301
Total assets	$ 1,580,240	$ 1,487,979
Liabilities and Stockholders Equity		
Current liabilities		
Trade accounts payable	$ 126,785	$ 89,430
Oil and gas sales payable	82,979	66,179
Accrued liabilities	17,485	10,805
Commodity derivative liabilities	11,830	10,664
Asset retirement obligations	2,794	2,590
Total current liabilities	241,873	179,668
Long-term debt	678,000	658,000
Deferred revenue	14,287	14,531
Commodity derivative liabilities	104	190
Asset retirement obligations	8,633	8,373
Deferred tax liabilities	3,375	3,093
Total liabilities	946,272	863,855
Commitments and contingencies (Note 9)		
Stockholders equity		
Class A common stock, $0.001 par value; 12,526,580 shares issued and outstanding	13	13
Class B common stock, $0.001 par value; 36,836,333 shares issued and outstanding	37	37
Additional paid-in-capital	173,626	173,169
Retained deficit	(514)	(2,186)

Stockholders equity		173,162		171,033
Non-controlling interest		460,806		453,091
Total stockholders equity		633,968		624,124
Total liabilities and stockholders equity	$	1,580,240	$	1,487,979

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

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Jones Energy, Inc.

Consolidated Statements of Operations (Unaudited)

(in thousands of dollars except per share data)	Three Months Ended March 31, 2014	2013
Operating revenues		
Oil and gas sales	$ 97,867	$ 55,259
Other revenues	377	221
Total operating revenues	98,244	55,480
Operating costs and expenses		
Lease operating	10,014	5,345
Production taxes	4,762	2,452
Exploration	2,821	126
Depletion, depreciation and amortization	39,345	25,101
Accretion of discount	170	97
General and administrative (including non-cash compensation expense)	5,260	4,312
Total operating expenses	62,372	37,433
Operating income	35,872	18,047
Other income (expense)		
Interest expense	(8,043)	(8,187)
Net loss on commodity derivatives	(17,250)	(11,383)
Gain on sales of assets	65	70
Other income (expense), net	(25,228)	(19,500)
Income (loss) before income tax	10,644	(1,453)
Income tax provision	1,257	(1)
Net income (loss)	9,387	(1,452)
Net income attributable to non-controlling interests	7,715	
Net income (loss) attributable to controlling interests	$ 1,672	$ (1,452)
Earnings per share:		
Basic	$ 0.13	
Diluted	$ 0.13	
Weighted average shares outstanding:		
Basic	12,500	
Diluted	12,512	

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

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Jones Energy, Inc.

Consolidated Statement of Changes In Stockholders Equity (Unaudited)

(amounts in thousands)	Common Stock Class A Shares	Class A Value	Class B Shares	Class B Value	Additional Paid-in-Capital	Retained Earnings	Non-controlling Interest	Total Stockholders Equity
Balance at December 31, 2013	12,500	13	36,836	37	173,169	(2,186)	453,091	624,124
Stock-compensation expense					457			457
Net income						1,672	7,715	9,387
Balance at March 31, 2014	12,500	$ 13	36,836	$ 37	$ 173,626	$ (514)	$ 460,806	$ 633,968

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

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Jones Energy, Inc.

Consolidated Statements of Cash Flows (Unaudited)

(in thousands of dollars)	**Three Months Ended March 31, 2014**	**2013**
Cash flows from operating activities		
Net income (loss)	$ 9,387	$ (1,452)
Adjustments to reconcile net income to net cash provided by operating activities		
Exploration expense	2,767	
Depletion, depreciation, and amortization	39,345	25,101
Accretion of discount	170	97
Amortization of debt issuance costs	700	664
Stock compensation expense	457	120
Other non-cash compensation expense	127	
Amortization of deferred revenue	(244)	
Net loss on commodity derivatives	17,250	11,383
Gain on sales of assets	(65)	(70)
Deferred income taxes	966	(23)
Other - net	67	165
Changes in assets and liabilities		
Accounts receivable	(46,893)	(7,846)
Other assets	428	(2,768)
Accounts payable and accrued liabilities	35,746	5,625
Net cash provided by operations	60,208	30,996
Cash flows from investing activities		
Additions to oil and gas properties	(85,028)	(36,883)
Net adjustments to purchase price of properties acquired	13,681	
Proceeds from sales of assets	66	2
Acquisition of other property, plant and equipment	(270)	(51)
Current period settlements of matured derivative contracts	(4,663)	4,039
Change in restricted cash	(22)	
Net cash used in investing	(76,236)	(32,893)
Cash flows from financing activities		
Proceeds from issuance of long-term debt	20,000	
Repayment under long-term debt		(5,000)
Payment of debt issuance costs	(495)	(25)
Net cash provided by (used in) financing	19,505	(5,025)
Net increase (decrease) in cash	3,477	(6,922)
Cash		
Beginning of period	23,820	23,726
End of period	$ 27,297	$ 16,804
Supplemental disclosure of cash flow information		
Cash paid for interest	$ 6,814	$ 6,325
Change in accrued additions to oil and gas properties	22,714	6,625
Current additions to ARO	330	69
Deferred offering costs	408	1,534

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

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Jones Energy, Inc.

Notes to the Consolidated Financial Statements (Unaudited)

1. Organization and Description of Business

Organization

Jones Energy, Inc. (the Company) was formed in March 2013 as a Delaware corporation to become a publicly traded entity and the holding company of Jones Energy Holdings, LLC (JEH). As the sole managing member of JEH, Jones Energy, Inc. is responsible for all operational, management and administrative decisions relating to JEH s business and consolidates the financial results of JEH and its subsidiaries.

JEH was formed as a Delaware limited liability company on December 16, 2009 through investments made by the Jones family and through private equity funds managed by Metalmark Capital and Wells Fargo Energy Capital. JEH acts as a holding company of operating subsidiaries that own and operate assets that are used in the exploration, development, production and acquisition of oil and natural gas properties.

Pursuant to the terms of a corporate reorganization that was completed in connection with the closing of Jones Energy, Inc. s initial public offering (IPO) on July 29, 2013, the pre-IPO owners of JEH converted their existing membership interests in JEH into JEH Units and amended the existing LLC agreement to, among other things, modify its equity capital to consist solely of JEH Units and to admit Jones Energy, Inc. as the sole managing member of JEH. Jones Energy, Inc. s certificate of incorporation authorizes two classes of common stock, Class A common stock and Class B common stock. Only Class A common stock was offered to investors pursuant to the IPO. The Class B common stock is held by the pre-IPO owners of JEH and can be exchanged (together with a corresponding number of JEH Units) for shares of Class A common stock on a one-for-one basis, subject to customary conversion rate adjustments for stock splits, stock dividends and reclassifications and other similar transactions. The Class B common stock has no economic rights but entitles its holder to one vote on all matters to be voted on by the Company s stockholders generally. As a result of the IPO, the pre-IPO owners retained 74.7% of the total economic interest in JEH, but with no voting rights or management power over JEH, resulting in the Company reporting this ownership interest as a non-controlling interest.

Description of Business

The Company is engaged in the acquisition, exploration, and production of oil and natural gas properties in the mid-continent United States. The Company s assets are located within two distinct basins in the Texas Panhandle and Oklahoma, the Anadarko Basin and the Arkoma Basin, and are owned by JEH and its operating subsidiaries. The Company operates in one industry segment and all of its operations are conducted in one geographic area of the United States. The Company is headquartered in Austin, Texas.

Revision of Previously Issued Financial Statements

In conjunction with our year-end audit and the preparation of our annual Form 10-K, we identified an error in our previously issued financial statements which would have been material to our fourth quarter of 2013 if recorded as an out of period adjustment in such period. We recorded the adjustments on a quarterly basis in prior periods and therefore, have revised our Consolidated Statement of Operations for the three months ended March 31, 2013 to record $0.2 million of additional interest expense on obligations that are unrelated to our credit agreements discussed in Note 6.

2. Significant Accounting Policies

Basis of Presentation

The accompanying consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (GAAP). All significant intercompany

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Jones Energy, Inc.

Notes to the Consolidated Financial Statements (Unaudited)

transactions and balances have been eliminated in consolidation. The financial statements reported for March 31, 2014, and the three month period then ended include the Company and all of its subsidiaries.

These interim financial statements have not been audited. However, in the opinion of management, all adjustments consisting of only normal and recurring adjustments necessary for a fair statement of the financial statements have been included. As these are interim financial statements, they do not include all disclosures required for financial statements prepared in conformity with GAAP. Interim period results are not necessarily indicative of results of operations or cash flows for a full year.

These consolidated financial statements have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission (SEC) regarding interim financial reporting. Accordingly, they do not include all disclosures required by GAAP and should be read in conjunction with our most recent audited consolidated financial statements included in Jones Energy, Inc. s Annual Report on Form 10-K for the year ended December 31, 2013.

Use of Estimates

In preparing the accompanying financial statements, management has made certain estimates and assumptions that affect the reported amounts of assets and liabilities, disclosure of contingent liabilities, and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from these estimates. Changes in estimates are recorded prospectively.

Significant assumptions are required in the valuation of proved oil and natural gas reserves, which affect the Company s estimates of depletion expense, impairment, and the allocation of value in our business combinations. Significant assumptions are also required in the Company s estimates of the net gain or loss on commodity derivative assets, fair value associated with business combinations, and asset retirement obligations (ARO).

Oil and Gas Properties

The Company accounts for its oil and natural gas exploration and production activities under the successful efforts method of accounting. Oil and gas properties consisted of the following at March 31, 2014 and December 31, 2013:

	March 31,	December 31,

(in thousands of dollars)		**2014**		**2013**
Mineral interests in properties				
Unproved	$	93,386	$	99,134
Proved		970,222		958,816
Wells and equipment and related facilities		709,358		609,748
		1,772,966		1,667,698
Less: Accumulated depletion and impairment		(409,573)		(370,470)
Net oil and gas properties	$	1,363,393	$	1,297,228

Costs to acquire mineral interests in oil and natural gas properties are capitalized. Costs to drill and equip development wells and the related asset retirement costs are capitalized. The costs to drill and equip exploratory wells are capitalized pending determination of whether the Company has discovered proved commercial reserves. If proved commercial reserves are not discovered, such drilling costs are charged to expense. In some circumstances, it may be uncertain whether proved commercial reserves have been found when drilling has been completed. Such exploratory well drilling costs may continue to be capitalized if the anticipated reserve quantity is sufficient to justify its completion as a producing well and sufficient progress

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Notes to the Consolidated Financial Statements (Unaudited)

in assessing the reserves and the economic and operating viability of the project is being made. In the first quarter of 2014 we had no material capitalized costs associated with exploratory wells.

The Company capitalizes interest on expenditures for significant exploration and development projects that last more than six months while activities are in progress to bring the assets to their intended use. The Company did not capitalize any interest during the three months ended March 31, 2014 as no projects lasted more than six months. Depletion of oil and gas properties amounted to $39.1 million and $24.9 million for the periods ended March 31, 2014 and March 31, 2013, respectively.

Other Property, Plant and Equipment

Other property, plant and equipment consisted of the following at March 31, 2014 and December 31, 2013:

(in thousands of dollars)	March 31, 2014	December 31, 2013
Leasehold improvements	$ 1,116	$ 1,060
Furniture, fixtures, computers and software	2,705	2,491
Vehicles	833	835
Aircraft	910	910
Other	133	134
	5,697	5,430
Less: Accumulated depreciation and amortization	(2,225)	(1,986)
Net other property, plant and equipment	$ 3,472	$ 3,444

Other property, plant and equipment is depreciated on a straight-line basis over the estimated useful lives of the property, plant and equipment, which range from three years to ten years. Depreciation and amortization of other property, plant and equipment amounted to $0.2 million and $0.2 million during the three months ended March 31, 2014 and 2013, respectively.

Commodity Derivatives

The Company records its commodity derivative instruments on the Consolidated Balance Sheet as either an asset or liability measured at its fair value. Changes in the derivative s fair value are recognized currently in earnings, unless specific hedge accounting criteria are met. During the three month periods ended March 31, 2014 and 2013, the Company elected not to designate any of its commodity price risk management activities as cash-flow or fair value hedges. The changes in the fair values of outstanding financial instruments are recognized as gains or losses in the period of change.

Although the Company does not designate its commodity derivative instruments as cash-flow hedges, management uses those instruments to reduce the Company s exposure to fluctuations in commodity prices related to its natural gas and oil production. Net gains and losses, at fair value, are included on the Consolidated Balance Sheet as current or noncurrent assets or liabilities based on the anticipated timing of cash settlements under the related contracts. Changes in the fair value of commodity derivative contracts are recorded in earnings as they occur and are included in other income (expense) on the Consolidated Statement of Operations. See Note 4, Fair Value Measurement, for disclosure about the fair values of commodity derivative instruments.

Asset Retirement Obligations

The Company s asset retirement obligations consist of future plugging and abandonment expenses on oil and natural gas properties.

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Notes to the Consolidated Financial Statements (Unaudited)

A summary of the Company s ARO for three months ended March 31, 2014 is as follows:

(in thousands of dollars)		
Balance at December 31, 2013	$	10,963
Liabilities incurred		330
Accretion of discount		170
Liabilities settled due to sale of related properties		
Liabilities settled due to plugging and abandonment		(49)
Change in estimate		13
Balance at March 31, 2014		11,427
Less: Current portion of ARO		(2,794)
Total long-term ARO at March 31, 2014	$	8,633

Income Taxes

Following its IPO on July 29, 2013, the Company began recording a federal and state income tax liability associated with its status as a corporation. No provision for federal income taxes was recorded prior to the IPO because the taxable income or loss was includable in the income tax returns of the individual partners and members. The Company is also subject to state income taxes. The State of Texas includes in its tax system a franchise tax applicable to the Company and an accrual for franchise taxes is included in the financial statements when appropriate.

Income taxes are accounted for under the asset and liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements. Under this method, deferred tax assets and liabilities are determined based on the differences between the financial statements and tax basis of assets and liabilities using enacted tax rates in effect for the year in which differences are expected to be recovered or settled pursuant to the provisions of ASC 740 Income Taxes. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date.

The Company records a valuation allowance if it is deemed more likely than not that all or a portion of its deferred income tax assets will not be realized. In addition, income tax rules and regulations are subject to interpretation and the application of those rules and regulations require judgment by the Company and may be challenged by the taxation authorities. The Company follows ASC 740-10-25, which requires the use of a two-step approach for recognizing and measuring tax benefits taken or expected to be taken in a tax return and disclosures regarding uncertainties in income tax positions. Only tax positions that meet the more likely than not recognition threshold are recognized. The Company s policy is to include any interest and penalties recorded on uncertain tax positions as a component of income tax expense. The Company s unrecognized tax benefits or related interest and penalties are immaterial.

Tax Receivable Agreement

In conjunction with the IPO, the Company entered into a Tax Receivable Agreement (TRA) with JEH and the pre-IPO owners. Upon any exchange of JEH Units and Class B common stock of the Company held by JEH s pre-IPO owners for Class A common stock of the Company, the TRA provides for the payment by the Company, directly to such exchanging owners, of 85% of the amount of cash savings in income or franchise taxes that the Company realizes as a result of (i) the tax basis increases resulting from the exchange of JEH Units for shares of Class A common stock (or resulting from a sale of JEH Units for cash) and (ii) imputed interest deemed to be paid by the Company as a result of, and additional tax basis arising from, any payments the Company makes under the TRA. The Company will retain the benefit of the remaining 15% of the cash

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savings. Liabilities under the TRA will be recognized upon the exchange of shares. As of March 31, 2014, there had been no exchanges and no liability is recorded on the Consolidated Balance Sheet.

Stock Compensation

JEH has a management incentive plan that provides membership-interest awards in JEH to members of senior management (management units). The management unit grants awarded prior to the initial filing of the registration statement in March 2013 had a dual vesting schedule. Sixty percent of the units awarded vested in five equal annual installments, with the remaining 40% vesting upon a company restructuring event, including the IPO. All grants awarded after the initial registration statement but prior to the IPO have a single vesting structure of five equal annual installments and were valued at the IPO price, adjusted for equivalent shares. Both the vested and unvested management units were converted into JEH Units and shares of Class B common stock at the IPO date.

Under the Jones Energy, Inc. 2013 Omnibus Incentive Plan, established in conjunction with the Company s IPO, the Company reserved 3,850,000 shares of Class A common stock for director and employee stock-based compensation awards. As of March 31, 2014 no such awards had been issued or granted to any of the Company s employees.

In September 2013, the Company granted each of the four outside members of the Board of Directors 6,645 shares of restricted Class A common stock under the Jones Energy, Inc. 2013 Omnibus Incentive Plan. The fair value of the restricted stock grants was based on the value of the Company s Class A common stock on the date of grant and is expensed on a straight-line basis over the one-year vesting period.

Refer to Note 7, Stock-based Compensation, for additional information regarding the management units and restricted stock awards.

Recent Accounting Developments

There are no recent accounting developments applicable to the Company as of March 31, 2014.

3. Acquisition of Properties

No property acquisitions that would qualify as a business combination occurred during the three months ended March 31, 2014.

On December 18, 2013, JEH closed on the purchase of certain oil and natural gas properties located in Texas and western Oklahoma from Sabine Mid-Continent, LLC, for a purchase price of $193.5 million (referred to herein as the Sabine acquisition or Sabine), subject to customary closing adjustments. The acquired assets include both producing properties and undeveloped acreage. The purchase was financed with borrowings under the senior secured credit facility.

In connection with the closing, approximately $24 million of the purchase price was placed in an escrow account. This amount represented the allocated value of the Sabine properties that had unresolved title defects claimed by JEH. In March, the Company settled the title negotiations resulting in $13.7 million of the escrowed funds being returned to the Company. In addition, preliminary adjustments to the purchase price totaling $1.6 million were accrued as of the end of the quarter. The amount of the total purchase price allocated to unproven oil and gas properties was reduced by these adjustments. The adjustments were retroactively applied to our December 31, 2013 Consolidated Balance Sheet as a reduction to oil and gas properties and an increase in receivables. The adjusted purchase price is allocated as follows:

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Jones Energy, Inc.

Notes to the Consolidated Financial Statements (Unaudited)

(in thousands of dollars)

Oil and gas properties		
Unproved	$	24,273
Proved		154,724
Asset retirement obligations		(824)
Total purchase price	$	178,173

This acquisition qualified as a business combination under ASC 805. The valuation to determine the fair value was principally based on the discounted cash flows of the producing and undeveloped properties, including projected drilling and equipment costs, recoverable reserves, production streams, future prices and operating costs, and risk-adjusted discount rates reflective of the current market. The determination of fair value is dependent on factors as of the acquisition date and the final adjustments to the purchase price, which when they occur, may result in an adjustment to the value of the acquired properties reflected in the consolidated financial statements. Any such adjustment may be material.

The unaudited pro forma results presented below have been prepared to give the effect of the acquisition on our results of operations for the quarter ended March 31, 2013. The unaudited pro forma results do not purport to represent what our actual results of operations would have been if the acquisition had been completed on January 1, 2013 or to project our results of operations for any future date or period.

	Three Months Ended March 31, 2013	
(in thousands of dollars)	**Actual**	**Pro Forma**
Total operating revenue	$ 55,480	$ 69,668
Total operating expenses	37,433	44,668
Operating income (loss)	18,047	25,000
Net income (loss)	(1,452)	5,501

4. Fair Value Measurement

Fair Value of Financial Instruments

The Company determines fair value amounts using available market information and appropriate valuation methodologies. Fair value is the price that would be received to sell an asset or would be paid to transfer a liability in an orderly transaction between market participants at the measurement date. Considerable judgment is required in interpreting market data to develop the estimates of fair value. The use of different market assumptions and/or estimation methods may have a material effect on the estimated fair value amounts.

The Company enters into a variety of derivative financial instruments, which may include over-the-counter instruments, such as natural gas, crude oil, and natural gas liquid contracts. The Company utilizes valuation techniques that maximize the use of observable inputs, where available. If listed market prices or quotes are not published, fair value is determined based upon a market quote, adjusted by other market-based or independently sourced market data, such as trading volume, historical commodity volatility, and counterparty-specific considerations. These adjustments may include amounts to reflect counterparty credit quality, the time value of money, and the liquidity of the market.

Counterparty credit valuation adjustments are necessary when the market price of an instrument is not indicative of the fair value as a result of the credit quality of the counterparty. Generally, market quotes assume that all counterparties have low default rates and equal credit quality. Therefore, an adjustment may

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Jones Energy, Inc.

Notes to the Consolidated Financial Statements (Unaudited)

be necessary to reflect the quality of a specific counterparty to determine the fair value of the instrument. The Company currently has all of its derivative positions placed and held by members of its lending group, which have strong credit quality.

Liquidity valuation adjustments are necessary when the Company is not able to observe a recent market price for financial instruments that trade in less active markets. Exchange traded contracts are valued at market value without making any additional valuation adjustments; therefore, no liquidity reserve is applied.

Valuation Hierarchy

Fair value measurements are grouped into a three-level valuation hierarchy. The valuation hierarchy is based upon the transparency of inputs to the valuation of an asset or liability as of the measurement date. A financial instrument s categorization within the hierarchy is based upon the input that requires the highest degree of judgment in the determination of the instrument s fair value. The three levels are defined as follows:

Level 1 Pricing inputs are based on published prices in active markets for identical assets or liabilities as of the reporting date. The Company does not classify any of its financial instruments as Level 1.

Level 2 Pricing inputs include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, as of the reporting date. Contracts that are not traded on a recognized exchange or are tied to pricing transactions for which forward curve pricing is readily available are classified as Level 2 instruments. These include natural gas, crude oil and some natural gas liquids price swaps and natural gas basis swaps.

Level 3 Pricing inputs include significant inputs that are generally unobservable from objective sources. The Company classifies natural gas liquid swaps and basis swaps for which future pricing is not readily available as Level 3. The Company obtains estimates from independent third parties for its open positions and subjects those to the credit adjustment criteria described above.

The financial instruments carried at fair value as of March 31, 2014 and December 31, 2013, by consolidated balance sheet caption and by valuation hierarchy, as described above are as follows:

March 31, 2014

(in thousands of dollars) Commodity Price Hedges	Fair Value Measurements (Level 1)	(Level 2)	(Level 3)	Total
Current assets		$ 4,289	$ (121)	$ 4,168
Long-term assets		20,796	10	20,806
Current liabilities		11,214	616	11,830
Long-term liabilities			104	104

(in thousands of dollars) Commodity Price Hedges	December 31, 2013 Fair Value Measurements (Level 1)	(Level 2)	(Level 3)	Total
Current assets	$	$ 8,837	$	$ 8,837
Long-term assets		25,967	(569)	25,398
Current liabilities		10,188	476	10,664
Long-term liabilities			190	190

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Jones Energy, Inc.

Notes to the Consolidated Financial Statements (Unaudited)

The following table represents quantitative information about Level 3 inputs used in the fair value measurement of the Company s commodity derivative contracts as of March 31, 2014.

Commodity Price Hedges	Fair Value	Quantitative Information About Level 3 Fair Value Measurements Valuation Technique	Unobservable Input	Range
Natural gas liquid swaps		Use a discounted cash flow approach using inputs including forward price statements from counterparties	Natural gas liquid futures prices	$8.93 - $84.68 per barrel
Basis swaps		Use a discounted cash flow approach using inputs including forward price statements from counterparties	Forward basis prices	$(0.22) - $0.25 per mmbtu

Significant increases/decreases in natural gas liquid futures in isolation would result in a significantly lower/higher fair value measurement. The following table presents the changes in the Level 3 financial instruments for the three months ended March 31, 2014. Changes in fair value of Level 3 instruments represent changes in gains and losses for the periods that are reported in other income (expense). New contracts entered into during the year are generally entered into at no cost with changes in fair value from the date of agreement representing the entire fair value of the instrument. Transfers between levels are evaluated at the end of the reporting period.

(in thousands of dollars)

Balance at December 31, 2013, net	$	(1,235)
Purchases		
Settlements		
Transfers to Level 2		(152)
Transfers to Level 3		(204)
Changes in fair value		760
Balance at March 31, 2014, net	$	(831)

Transfers from Level 3 to Level 2 represent all of the Company s natural gas liquids swaps for which observable forward curve pricing information has become readily available. Transfers to Level 3 represent hedges that were previously considered Level 2 but due to the unavailability of forward prices at the valuation date were classified as Level 3 as of March 31, 2014. There were no purchases or settlements in the period that resulted in changes to Level 3.

Offsetting Assets and Liabilities

As of March 31, 2014 the counterparties to our commodity derivative contracts consisted of six financial institutions. All of our counterparties or their affiliates are also lenders under our credit facility. Therefore, we are not generally required to post additional collateral under our derivative agreements.

Our derivative agreements contain set-off provisions that state that in the event of default or early termination, any obligation owed by the defaulting party may be offset against any obligation owed to the defaulting party.

We adopted the guidance requiring disclosure of both gross and net information about financial instruments eligible for netting in the balance sheet under our derivative agreements. The following table presents information about our commodity derivative contracts which are netted on our Consolidated Balance Sheet as of March 31, 2014 and December 31, 2013:

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Notes to the Consolidated Financial Statements (Unaudited)

(in thousands)	Gross Amounts of Recognized Assets / Liabilities	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets / Liabilities Presented in the Balance Sheet	Gross Amounts Not Offset in the Balance Sheet	Net Amount
March 31, 2014					
Commodity derivative contracts					
Assets	32,656	(7,807)	24,849	125	24,974
Liabilities	(19,741)	7,807	(11,934)		(11,934)
December 31, 2013					
Commodity derivative contracts					
Assets	38,071	(6,035)	32,036	2,199	34,235
Liabilities	(14,347)	6,035	(8,312)	(2,542)	(10,854)

Nonfinancial Assets and Liabilities

Assets and liabilities acquired in business combinations are recorded at their fair value on the date of acquisition. Significant Level 3 assumptions associated with the calculation of future cash flows used in the analysis of fair value of the oil and gas property acquired include the Company s estimate of future commodity prices, production costs, development expenditures, production, risk-adjusted discount rates, and other relevant data. Additionally, fair value is used to determine the inception value of the Company s AROs. The inputs used to determine such fair value are primarily based upon costs incurred historically for similar work, as well as estimates from independent third parties for costs that would be incurred to restore leased property to the contractually stipulated condition. Additions to the Company s ARO represent a nonrecurring Level 3 measurement.

The Company reviews its proved oil and gas properties for impairment purposes by comparing the expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. No impairment charges on the Company s proved properties were recorded during the three months ended March 31, 2014. Additionally, the Company assessed its unproved properties for impairment as of March 31, 2014 and no impairments were noted. In the event of an impairment, charges are recorded on the Consolidated Statement of Operations. Significant assumptions associated with the calculation of future cash flows used in the impairment analysis include the Company s estimate of future commodity prices, production costs, development expenditures, production, risk-adjusted discount rates, and other relevant data. As such, the fair value of oil and gas properties used in estimating impairment represents a nonrecurring Level 3 measurement.

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Jones Energy, Inc.

Notes to the Consolidated Financial Statements (Unaudited)

5. Derivative Instruments and Hedging Activities

The Company had various commodity derivatives in place to offset uncertain price fluctuations that could affect its future operations as of March 31, 2014 and December 31, 2013, as follows:

Hedging Positions

		March 31, 2014			
		Low	**High**	**Weighted Average**	**Final Expiration**
Oil swaps	Exercise price	$ 81.70	$ 102.33	$ 88.78	
	Barrels per month	29,000	157,884	91,912	December 2017
Natural gas swaps	Exercise price	$ 3.88	$ 6.90	$ 4.84	
	mmbtu per month	510,000	1,220,000	802,738	December 2017
Basis swaps	Contract differential	$ (0.43)	$ (0.11)	$ (0.33)	
	mmbtu per month	320,000	630,000	441,667	March 2016
Natural gas liquids swaps	Exercise price	$ 6.72	$ 95.24	$ 33.64	
	Barrels per month	2,000	115,000	42,000	December 2017

		December 31, 2013			
		Low	**High**	**Weighted Average**	**Final Expiration**
Oil swaps	Exercise price	$ 81.70	$ 102.84	$ 89.03	
	Barrels per month	29,000	161,613	96,149	December 2017
Natural gas swaps	Exercise price	$ 3.88	$ 6.90	$ 4.26	
	mmbtu per month	510,000	1,290,000	830,275	December 2017
Basis swaps	Contract differential	$ (0.43)	$ (0.11)	$ (0.34)	
	mmbtu per month	320,000	690,000	467,037	March 2016
Natural gas liquids swaps	Exercise price	$ 6.72	$ 95.24	$ 32.98	
	Barrels per month	2,000	118,000	46,646	December 2017

The Company recognized a net loss on derivative instruments of $17.3 million for the three months ended March 31, 2014 and a net loss of $11.4 million for the three months ended March 31, 2013.

6. Long-Term Debt

In December 2009, the Company entered into two credit agreements, with Wells Fargo Bank N.A, the Senior Secured Revolving Credit Facility (the Revolver) and the Second Lien Term Loan (the Term Loan), each of which were subsequently amended in November 2011, November 2012, December 2012, June 2013, December 2013 and January 2014. In connection with the November 2012 amendment, the maturity date of the Revolver was extended to November 5, 2017 and the maturity date of the Term loan was extended to May 5, 2018. In connection with the June 2013 amendment, the borrowing base on the Revolver was increased to $500.0 million, and in connection with the December 2013 amendment, the borrowing base on the Revolver was subsequently increased to $575.0 million in conjunction with the Sabine acquisition. The Company s oil and gas properties are pledged as collateral against these credit agreements.

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Notes to the Consolidated Financial Statements (Unaudited)

Terms of the Revolver require the Company to pay interest on the loan on the earlier of the London InterBank Offered Rate (LIBOR) tranche maturity date or three months, with the entire principal and interest due on the loan maturity date. Borrowings may be drawn on the principal amount up to the maximum available credit amount. Interest on the Revolver is calculated at a base rate (LIBOR or prime), plus a margin of 0.50% to 2.50% based on the actual amount borrowed compared to the borrowing base amount and the base rate selected. For the three months ended March 31, 2014, the average interest rate under the Revolver was 2.87% on an average outstanding balance of $510.4 million.

Terms of the Term Loan require the Company to pay interest on the loan every three months with the principal and interest due on the loan maturity date of May 5, 2018. Interest on the Term Loan is calculated at a base rate (LIBOR, prime, or federal funds), plus a margin of 6% to 7% based on the base rate selected. For the three months ended March 31, 2014, the average interest rate under the Term Loan was 9.13% on an average outstanding balance of $160.0 million.

Total interest and commitment fees under the two facilities were $7.3 million and $7.3 million for the three months ended March 31, 2014 and 2013, respectively.

The Revolver and Term Loans are categorized as Level 3 in the valuation hierarchy as the debt is not publicly traded and no observable market exists to determine the fair value; however, the carrying value of the Revolver and Term Loans approximate fair value, as they are subject to short-term floating interest rates that approximate the rates available to the Company for those periods.

The Revolver and Term Loans include covenants that require, among other things, restrictions on asset sales, distributions to members, and additional indebtedness, and the maintenance of certain financial ratios, including leverage, proven reserves to debt, and current ratio. The Company was in compliance with these covenants at March 31, 2014.

7. Stock-based Compensation

JEH granted membership-interest awards in JEH to members of senior management (management units) under a management incentive plan prior to the IPO. These awards had various vesting schedules, and a portion of the management units vested in a lump sum at the IPO date. Both the vested and unvested management units were converted into JEH Units and shares of Class B common stock at the IPO date. As of March 31, 2014, there were 457,150 unvested JEH Units and shares of Class B common stock. The Units/shares will become convertible into a like number of shares of Class A common stock upon vesting. The following table summarizes information related to the Units/shares held by management:

	JEH Units	Weighted Average Grant Date Fair Value per Share

Unvested at January 1, 2014	457,150	$	12.46
Granted			
Forfeited			
Vested			
Unvested at March 31, 2014	457,150	$	12.46

Stock compensation expense associated with the management units for the three months ended March 31, 2014 and 2013 was $0.4 million and $0.1 million, respectively, and is included in general and administrative expenses on the Company s Consolidated Statement of Operations.

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On September 4, 2013, the Company granted restricted stock awards to non-employee members of the Board of Directors. Each of the four directors was awarded 6,645 restricted shares of Class A common stock, contingent on the director serving as a director of the Company for a one-year service period from the date of grant. The fair value of the awards was based on the value of the Company s Class A common stock on the date of grant. The total value of the awards to the directors is as follows:

	Restricted Stock Awards	Weighted Average Grant Date Fair Value per Share
Unvested at January 1, 2014	26,580	$ 15.05
Granted		
Forfeited		
Vested		
Unvested at March 31, 2014	26,580	$ 15.05

Stock compensation expense associated with the Board of Directors awards for the three months ended March 31, 2014 was $0.1 million and is included in general and administrative expenses on the Company s Consolidated Statement of Operations.

8. Earnings per Share

Basic earnings per share (EPS) is computed by dividing net income (loss) attributable to controlling interests by the weighted-average number of shares of Class A common stock outstanding during the period. Class B common stock is not included in the calculation of earnings per share because they are not participating securities and have no economic interest in the Company. Diluted earnings per share takes into account the dilutive effect of potential common stock that could be issued by the Company in conjunction with stock awards that have been granted to directors and employees. On September 4, 2013 (the grant date), the Company granted to its directors restricted shares of Class A common stock, which vest on the first anniversary of the grant date. In accordance with ASC 260, Earnings Per Share, awards of nonvested shares shall be considered outstanding as of the grant date for purposes of computing diluted EPS even though their exercise is contingent upon vesting. The following is a calculation of the basic and diluted weighted-average number of shares of Class A common stock outstanding and EPS for the three months ended March 31, 2014.

(in thousands, except per share data)	Three Months Ended March 31, 2014
Income (numerator):	
Net income attributable to controlling interests	$ 1,672
Weighted-average shares (denominator):	
Weighted-average number of shares of Class A common stock - basic	12,500

Weighted-average number of shares of Class A common stock - diluted		12,512
Earnings per share:		
Basic	$	0.13
Diluted	$	0.13

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Jones Energy, Inc.

Notes to the Consolidated Financial Statements (Unaudited)

9. Commitments and Contingencies

The Company is subject to legal proceedings and claims that arise in the ordinary course of its business. The Company believes that the final disposition of such matters will not have a material adverse effect on its financial position, results of operations, or liquidity.

10. Income Taxes

Following its IPO, the the Company began recording federal and state income tax liabilities associated with its status as a corporation. Prior to the IPO, the Company only recorded a provision for Texas franchise tax as the Company s taxable income or loss was includable in the income tax returns of the individual partners and members. The Company will recognize a tax liability on its share of pre-tax book income, exclusive of the non-controlling interest. JEH is not subject to income tax at the federal level and only recognizes Texas franchise tax expense.

The Company s effective tax rate for the three months ended March 31, 2014 was 10.1%. The rate is consistent with the statutory tax rate applicable to the U.S. and the states in which the Company conducts its business. The effective rate differs from the statutory rate of 35% primarily due to net income allocated to the non-controlling interest and to state income taxes. The Company s income tax provision was an expense of $1.3 million and a benefit of $0.001 million for the three months ended March 31, 2014 and 2013, respectively. This includes income tax expense of $0.2 million and income tax benefit of $0.001 million for the three months ended March 31, 2014 and 2013, respectively, allocated to the non-controlling interest. As of March 31, 2014, the Company did not have any uncertain tax positions requiring adjustments to its tax liability.

The Company had deferred tax assets for its federal and state loss carryforwards at March 31, 2014 recorded in noncurrent deferred taxes. Deferred tax assets are reduced by a valuation allowance, when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized. As of March 31, 2014, management determined that a valuation alowance was not required for the tax loss carryforwards as they are expected to be fully utilized before expiration.

11. Subsequent Events

On April 1, 2014, JEH and Jones Energy Finance Corp. (the Issuers) sold $500 million in aggregate principal amount of the Issuers 6.75% Senior Notes due 2022 (the 2022 Notes). On April 1, 2014, the Company used the proceeds from the issuance of the 2022 Notes to repay all outstanding borrowings under the Term Loan and a portion of the borrowing under its Revolver. The Company subsequently terminated the Term Loan in accordance with its terms.

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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 in conjunction with the Management s Discussion and Analysis of Financial Condition and Results of Operations section and audited consolidated financial statements and related notes thereto included in our Annual Report on Form 10-K for the year ended December 31, 2013, filed on March 14, 2014 with the Securities and Exchange Commission, and with the unaudited consolidated financial statements and related notes thereto presented in this Quarterly Report. Unless indicated otherwise in this Quarterly Report or the context requires otherwise, all references to Jones Energy, the Company, our company, we, our and us refer to Jones Energy, Inc. and its subsidiaries, including Jones Energy Holdings, LLC (JEH LLC). Jones Energy, Inc. (JONE) is a holding company whose sole material asset is an equity interest in JEH LLC.

Overview

We are an independent oil and gas company engaged in the exploration, development, production and acquisition of oil and natural gas properties in the Anadarko and Arkoma basins of Texas and Oklahoma. Our Chairman and CEO, Jonny Jones, founded our predecessor company in 1988 in continuation of his family s long history in the oil and gas business, which dates back to the 1920 s. We have grown rapidly by leveraging our focus on low cost drilling and completion methods and our horizontal drilling expertise to develop our inventory and execute several strategic acquisitions. We have accumulated extensive knowledge and experience in developing the Anadarko and Arkoma basins, having concentrated our operations in the Anadarko basin for 25 years and applied our knowledge to the Arkoma basin since 2011. We have drilled over 675 total wells, including over 490 horizontal wells, since our formation and delivered compelling rates of return over various commodity price cycles. Our operations are focused on horizontal drilling and completions within two distinct basins in the Texas Panhandle and Oklahoma:

- the Anadarko Basin targeting the liquids rich Cleveland, Granite Wash, Tonkawa and Marmaton formations; and
- the Arkoma Basin targeting the Woodford shale formation.

We optimize returns through a disciplined emphasis on controlling costs and promoting operational efficiencies, and we believe we are recognized as one of the lowest cost drilling and completion operators in the Cleveland and Woodford shale formations.

The Anadarko and Arkoma basins are among the most prolific and largest onshore producing oil and natural gas basins in the United States, enjoying multiple producing horizons and extensive well control demonstrated over seven decades of development. The formations we target are generally characterized by oil and liquids rich natural gas content, extensive production histories, long lived reserves, high drilling success rates and attractive initial production rates. We focus on formations in our operating areas that we believe offer significant development and acquisition opportunities and to which we can apply our technical experience and operational excellence to increase proved reserves and production to deliver attractive economic rates of return. Our goal is to build value through a disciplined balance between developing our current inventory of 2,542 gross identified drilling locations and other opportunities within our existing asset base, and actively pursuing joint venture agreements, farm out agreements, joint operating agreements and similar partnering agreements, which we refer to as joint development agreements, organic leasing and strategic acquisitions. In all of our joint development agreements, we control the drilling and completion of a well, which is the phase during which we can leverage our operational expertise and cost discipline. Following completion, we in some cases may turn over operatorship to a partner during the production phase of a well. We believe the ceding to us of drilling and completion operatorship in our areas of operation by several large oil and gas companies, including ExxonMobil and BP, reflects their acknowledgement of our low cost, safe and efficient operations.

Our profitability and ability to grow depend principally on the prices we obtain for our hydrocarbons, the volumes we produce and our ability to drill and complete wells at lower costs than other operators in our areas. Oil, natural gas and NGL prices historically have been volatile, may fluctuate widely in the future and are dependent on factors beyond our control, such as economic, political and regulatory developments, as well as competition from other

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sources of energy. Development of unconventional oil and gas in the U.S. continues to change the landscape of the onshore resource as well as pricing for the commodities. Henry Hub natural gas spot price decreased from an average of $8.86 MMBtu in 2008 to an average of $3.65 MMBtu in 2013 as the local domestic supply of natural gas increased substantially and the commodity became decoupled from the price of oil. Over the same time period, as the global economic environment improved, West Texas Intermediate spot prices for oil ranged from less than $40 per barrel to greater than $140 per barrel. In light of price volatility, we continually evaluate and adjust our drilling program to allocate capital to wells that we believe will provide the most attractive returns. Additionally, we hedge a substantial portion of our expected future oil and gas production to reduce our exposure to fluctuations in commodity price. See Quantitative and qualitative disclosures about market risk Commodity price risk and hedges below for discussion of our hedging and hedge positions.

First Quarter 2014 Highlights:

- Increased average daily net production to a record 21.5 MBoe/d, up 19% from the fourth quarter of 2013
- Increased liquids as a percentage of total production to 57%, up from 52% in the fourth quarter of 2013
- Increased EBITDAX to $71.7 million, up 38% from the fourth quarter of 2013
- Increased Cleveland average daily net production to 15.6 MBoe/d, up 44% from the fourth quarter of 2013

Recent Developments

On April 1, 2014, JEH LLC and Jones Energy Finance Corp., which we refer to as the Issuers, issued $500,000,000 in aggregate principal amount of the Issuers 6.75% Senior Notes due 2022, or the 2022 Notes. The 2022 Notes were offered and sold in a transaction exempt from the registration requirements under the Securities Act of 1933, as amended. The 2022 Notes were resold to qualified institutional buyers in reliance on Rule 144A and Regulation S under the Securities Act. On April 1, 2014, we used a portion of the proceeds from the issuance of the 2022 Notes to repay all outstanding borrowings under our Second Lien Term Loan Credit Agreement, dated as of December 31, 2009, with Wells Fargo Energy Capital, Inc., as administrative agent, and the lenders party thereto. We subsequently terminated the Second Lien Term Loan Credit Agreement in accordance with its terms.

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Results of Operations

The following table summarizes our revenues, expenses and production data for the periods indicated.

(in thousands of dollars except for production, sales price and average cost data)	Three Months Ended March 31, 2014	2013	Change
Revenues:			
Oil	$ 53,924	$ 27,575	$ 26,349
Natural gas	21,385	12,788	8,597
NGLs	22,558	14,896	7,662
Total oil and gas	97,867	55,259	42,608
Other	377	221	156
Total operating revenues	98,244	55,480	42,764
Costs and expenses:			
Lease operating	10,014	5,345	4,669
Production taxes	4,762	2,452	2,310
Exploration	2,821	126	2,695
Depletion, depreciation and amortization	39,345	25,101	14,244
Accretion of discount	170	97	73
General and administrative	5,260	4,312	948
Total costs and expenses	62,372	37,433	24,939
Operating income	35,872	18,047	17,825
Other income (expenses):			
Interest expense	(8,043)	(8,187)	144
Net loss on commodity derivatives	(17,250)	(11,383)	(5,867)
Gain on sales of assets	65	70	(5)
Total other income (expense)	(25,228)	(19,500)	(5,728)
Income before income tax	10,644	(1,453)	12,097
Income tax provision	1,257	(1)	1,258
Net income (loss)	9,387	(1,452)	10,839
Net income (loss) attributable to non-controlling interests	7,715		7,715
Net income (loss) attributable to controlling interests	$ 1,672	$ (1,452)	$ 3,124
Net production volumes:			
Oil (MBbls)	575	312	263
Natural gas (MMcf)	5,009	4,266	743
NGLs (MBbls)	523	406	117
Total (MBoe)	1,933	1,429	504
Average net (Boe/d)	21,478	15,878	5,600
Average sales price, unhedged:			
Oil (per Bbl), unhedged	$ 93.78	$ 88.38	$ 5.40
Natural gas (per Mcf), unhedged	4.27	3.00	1.27
NGLs (per Bbl), unhedged	43.13	36.69	6.44
Combined (per Boe) realized, unhedged	50.63	38.67	11.96
Average sales price, hedged:			
Oil (per Bbl), hedged	$ 87.57	$ 86.26	$ 1.31
Natural gas (per Mcf), hedged	4.06	4.01	0.05
NGLs (per Bbl), hedged	38.75	36.91	1.84
Combined (per Boe) realized, hedged	47.05	41.29	5.76
Average costs (per Boe):			
Lease operating	$ 5.18	$ 3.74	$ 1.44

Production taxes	2.46	1.72	0.74
Depletion, depreciation and amortization	20.35	17.57	2.78
General and administrative	2.72	3.02	(0.30)

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Non-GAAP financial measure

EBITDAX is a supplemental non GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies.

We define EBITDAX as earnings before interest expense, income taxes, depreciation, depletion and amortization, exploration expense, gains and losses from derivatives less the current period settlements of matured derivative contracts and the other items described below, however, we may modify our definition of EBITDAX in the future. EBITDAX is not a measure of net income as determined by United States generally accepted accounting principles, or GAAP. Management believes EBITDAX is useful because it allows them to more effectively evaluate our operating performance and compare the results of our operations from period to period and against our peers without regard to financing methods or capital structure. We exclude the items listed above from net income in arriving at EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. EBITDAX has limitations as an analytical tool and should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with GAAP or as an indicator of our liquidity. Certain items excluded from EBITDAX are significant components in understanding and assessing a company s financial performance, such as a company s cost of capital and tax structure, as well as the historical costs of depreciable assets. Our presentation of EBITDAX should not be construed as an inference that our results will be unaffected by unusual or non-recurring items. Our computations of EBITDAX may not be comparable to other similarly titled measures of other companies.

The following table sets forth a reconciliation of net income (loss) as determined in accordance with GAAP to EBITDAX for the periods indicated:

	Three Months Ended March 31,	
(in thousands of dollars)	**2014**	**2013**
Reconciliation of EBITDAX to net income		
Net income (loss)	$ 9,387	$ (1,452)
Interest expense (excluding amortization of deferred financing costs)	7,343	7,523
Exploration expense	2,821	126
Income taxes	1,257	(1)
Amortization of deferred financing costs	700	664
Depreciation and depletion	39,345	25,101
Accretion expense	170	97
Other non-cash charges	67	165
Stock compensation expense	457	120
Other non-cash compensation expense	127	
Net loss on commodity derivatives	17,250	11,383
Current period settlements of matured derivative contracts	(6,909)	3,748
Amortization of deferred revenue	(244)	
Gain on sales of assets	(65)	(70)
EBITDAX	$ 71,706	$ 47,404

Adjusted Net Income is a supplemental non GAAP financial measure that is used by management and external users of the Company s consolidated financial statements.

We define Adjusted Net Income as net income excluding the impact of certain non-cash items including gains or losses on commodity derivative instruments not yet settled, impairment of oil and gas properties, and non-cash

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compensation expense. We believe adjusted net income is useful to investors because it provides readers with a more meaningful measure of our profitability before recording certain items for which the timing or amount cannot be reasonably determined. However, this measure is provided in addition to, not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP. Our computations of adjusted net income may not be comparable to other similarly titled measures of other companies. The following tables provide a reconciliation of net income (loss) as determined in accordance with GAAP to adjusted net income for the three months ended March 31, 2014 and 2013, respectively.

	Three Months Ended March 31,			
(in thousands of dollars except per share data)	**2014**		**2013**	
Net income (loss)	$	9,387	$	(1,452)
Net loss on commodity derivatives		17,250		11,383
Current period settlements of matured derivative contracts		(6,909)		3,748
Non-cash stock compensation expense		457		120
Other non-cash compensation expense		127		
Tax impact(1)		(1,029)		
Adjusted net income		19,283	$	13,799
Adjusted net income attributable to non-controlling interests		15,828		
Adjusted net income attributable to controlling interests	$	3,455		

	Three Months Ended March 31, 2014	
Earnings per share (basic and diluted)	$	0.13
Net loss on commodity derivatives		0.35
Current period settlements of matured derivative contracts		(0.14)
Non-cash stock compensation expense		0.01
Other non-cash compensation expense		0.01
Tax impact		(0.08)
Adjusted earnings per share (basic and diluted)	$	0.28
Effective tax rate on net income attributable to controlling interests		36.5%

(1) In arriving at adjusted net income, the tax impact of the adjustments to net income is determined by applying the appropriate tax rate to each adjustment and then allocating the tax impact between the controlling and non-controlling interests.

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Results of Operations - Three months ended March 31, 2014 as compared to three months ended March 31, 2013

Operating revenues

Oil and gas sales. Oil and gas sales increased $42.6 million, or 77.0%, to $97.9 million for the three months ended March 31, 2014, as compared to $55.3 million for the three months ended March 31, 2013. The increase is attributable to increases in both production volumes and average prices for all products. Average daily production increased 35.3% to 21,478 Boe per day for the three months ended March 31, 2014 as compared to 15,878 Boe per day for the three months ended March 31, 2013. Higher crude oil production accounted for the majority of the increase (57.9%), as volumes increased 263 MBbls, or 84.3%, in the first quarter of 2014 as compared to the first quarter of 2013. The significant increase is a result of increased drilling (four rigs running at the beginning of 2013 versus ten rigs running at the beginning of 2014) of primarily oil-based Chalker wells, the acquisition of 92 producing Sabine wells (which added 77 MBbls of crude oil production and $7.3 million in revenues in the quarter), and higher oil production from the Cleveland wells included in the enhanced frack trial. The increase in average prices for all products accounted for 22.8% of the positive variance. The average realized oil price, excluding the effects of commodity derivative instruments, increased from $88.38 per Bbl for the three months ended March 31, 2013 to $93.78 per Bbl for the three months ended March 31, 2014. The average realized natural gas price, excluding the effects of commodity derivative instruments, increased from $3.00 per Mcf to $4.27 per Mcf, or 42.3%. The average realized natural gas liquids price, excluding the effects of commodity derivative instruments, increased from $36.69 per Bbl to $43.13 per Bbl, or 17.6%.

Costs and expenses

Lease operating. Lease operating expenses increased $4.7 million, or 88.7%, to $10.0 million for the three months ended March 31, 2014, as compared to $5.3 million for the three months ended March 31, 2013. The increase in lease operating expenses is partially attributable to the 35.3% increase in production volumes from 15,878 Boe per day for the three months ended March 31, 2013 to 21,478 Boe per day for the three months ended March 31, 2014. On a per unit basis, lease operating expenses increased $1.44, or 38.5%, from $3.74 in first quarter of 2013 to $5.18 in the first quarter of 2014. Non-recurring expenses increased from $0.6 million for the three months ended March 31, 2013 to $1.7 million for the three months ended March 31, 2014, accounting for $0.48 of the $1.44 per unit increase. There were considerably more fracks performed in the first quarter of 2014 as compared to the first quarter of 2013, which contributed to the increase in non-recurring operating expenses as remediation work is required to get wells back on line after they are interrupted by nearby fracks. An additional $0.23 of the per unit variance can be specifically attributed to an increase in ad valorem taxes which is attributable to the increase in producing wells from new drilling and the producing properties acquired from Sabine. Operating expenses incurred on non-operated properties accounted for an additional $0.23 of the per unit increase. The remainder of the increase can be explained through increases in certain types of expenses such as compressors, chemicals and salt water disposal costs that are characteristic of the types of wells we are drilling.

Production taxes. Production taxes increased by $2.3 million (92.0%) to $4.8 million for the three months ended March 31, 2014, as compared to $2.5 million for the three months ended March 31, 2013. Overall production taxes increased in conjunction with the 77.0% increase in revenue; however, the average effective rate increased from 4.4% for the three months ended March 31, 2013 to 4.9% for the three months ended March 31, 2014. Production tax rates vary between states, products, and production levels; therefore, the overall blended rate can be impacted by numerous factors and the mix of producing wells at any given time. Production taxes were at higher rate during the three months ended March 31, 2014 as our recent focus has been on drilling Cleveland properties in Texas, which imposes a higher initial tax rate than in Oklahoma, where our other producing properties are located.

Exploration. Exploration expense increased from $0.1 million for the three months ended March 31, 2013 to $2.8 million for the three months ended March 31, 2014. During the quarter, we wrote off all capitalized costs associated with an exploratory well for which we did not find significant proved reserves.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $14.2 million (56.6%) to $39.3 million for the three months ended March 31, 2014, as compared to $25.1 million for the three months ended March 31, 2013. The increase was primarily the result of continued drilling activity and the addition of the Sabine properties at the end of 2013, which increased our total proved reserve base in the Cleveland

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formation. On a per unit basis, depletion expense increased $2.78 per Boe or 15.8% from $17.57 per Boe for the three months ended March 31, 2013 as compared to $20.35 per Boe for the three months March 31, 2014, attributable in part to the impairment of the Southridge properties in the fourth quarter of 2013.

General and administrative. General and administrative expenses increased by $1.0 million, or 23.3%, to $5.3 million for the three months ended March 31, 2014, as compared to $4.3 million for the three months ended March 31, 2013. Of this increase, $0.4 million related to stock compensation expense associated with the management units granted prior to our initial public offering and restricted stock granted to our directors. The remainder of the increase was primarily attributable to increases in third party professional fees including higher accounting, tax, and legal fees associated with being a public company. Excluding non-cash compensation expense, general and administrative expense decreased, on a per unit basis, from $2.93 per Boe for the three months ended March 31, 2013 to $2.42 for the three months ended March 31, 2014. The increase in activity resulting from our increased drilling program, combined with the acquisition of the Sabine properties, increased production (35.3% on a Boe basis) without a proportional increase in general and administrative expenses.

Net loss on commodity derivatives. The net loss on commodity derivatives increased by $5.9 million, or 51.8%, to a loss of $17.3 million for the three months ended March 31, 2014, as compared to a loss of $11.4 million for the three months ended March 31, 2013. The higher loss was driven by higher average crude oil and natural gas prices ($98.68 and $4.94 respectively) for the first quarter of 2014, as compared to the average crude oil and natural gas prices ($94.37 and $3.34, respectively) for the first quarter of 2013.

Income taxes. Our estimate for federal and state income taxes for the three months ended March 31, 2014 was an expense of $1.3 million as compared to a benefit of $0.001 million for the three months ended March 31, 2013. Our tax expense increased as a result of the change in tax status from a pass-through entity to a C corporation following our initial public offering in July 2013. Our effective tax rate is expected to approximate the statutory rate applicable to the U.S. and the blended rate of the states in which we conduct business, and is adjusted for the share of net income allocated to the non-controlling interest.

Liquidity and Capital Resources

Historically, our primary sources of liquidity have been private and public sales of our equity, borrowings under bank credit facilities and cash flows from operations. Our primary use of capital has been for the exploration, development and acquisition of oil and gas properties. As we pursue reserves and production growth, we continually consider which capital resources, including equity and debt financings, are available to meet our future financial obligations, planned capital expenditure activities and liquidity requirements. Our future ability to grow proved reserves and production will be highly dependent on the capital resources available to us. We strive to maintain financial flexibility in order to maintain substantial borrowing capacity under our senior secured revolving credit facility, facilitate drilling on our undeveloped acreage positions and permit us to selectively expand our acreage positions. Depending on the timing and concentration of the development of our non-proved locations, we may be required to generate or raise significant amounts of capital to develop all of our potential drilling locations should we endeavor to do so. In the event our cash flows are materially less than anticipated and other sources of capital we historically have utilized are not available on acceptable terms, we may curtail our capital spending. Our balance sheet at March 31, 2014 reflects a working capital deficit as we use the available balance of the borrowing base under our senior secured revolving credit facility to manage cash flow. The available borrowing base of $56.7 million exceeded the adjusted working capital deficit of $53.7 million, adjusted for commodity derivative instruments and the current portion of our asset retirement obligations.

On April 1, 2014, the Company closed on a $500 million offering of 6.75% senior unsecured notes due 2022 at an offering price equal to 100% of par. The Company received net proceeds of approximately $489 million, of which $160 million was used to repay all of the outstanding borrowings under its second lien term loan facility, with the remaining proceeds used to pay down borrowings under its senior secured revolving credit facility. The repayment on the Revolver made available over $300 million under the Company s borrowing base and significantly enhanced the Company s liquidity and working capital. The pro forma increase in interest expense as a result of the offering is estimated to be $13.3 million on an annual basis.

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Our capital budget is primarily focused on the development of existing core areas in the Cleveland and Woodford plays through exploitation and development. The amount of capital we expend may fluctuate materially based on market conditions, the economic returns being realized and the success of our drilling results.

The amount, timing and allocation of capital expenditures are largely discretionary and within management s control. If oil and gas prices decline to levels below our acceptable levels, or costs increase to levels above our acceptable levels, we may choose to defer a portion of our budgeted capital expenditures until later periods in order to achieve the desired balance between sources and uses of liquidity and prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flow. We may also increase our capital expenditures significantly to take advantage of opportunities we consider to be attractive. We consistently monitor and adjust our projected capital expenditures in response to success or lack of success in drilling activities, changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, contractual obligations, internally generated cash flow and other factors both within and outside our control.

The following table summarizes our cash flows for the three months ended March 31, 2014 and 2013:

(in thousands of dollars)	**Three Months Ended March 31, 2014**	**2013**
Net cash provided by operating activities	$ 60,208	$ 30,996
Net cash used in investing activities	(76,236)	(32,893)
Net cash provided by (used in) financing activities	19,505	(5,025)
Net increase (decrease) in cash	$ 3,477	$ (6,922)

Cash flow provided by operating activities

Net cash provided by operating activities was $60.2 million during the three months ended March 31, 2014 as compared to net cash provided by operating activities of $31.0 million during the three months ended March 31, 2013. The increase in operating cash flows was primarily due to the $42.6 million increase in oil and gas revenues during the three months ended March 31, 2014 as compared to the three months ended March 31, 2013, driven by a 35.3% increase in production between the two quarters and increases in prices for all products. The increase in cash flow was offset by a decrease in working capital resulting from an increase in drilling activity from four rigs running at March 31, 2013 to ten rigs running at March 31, 2014 and an increase in lease operating expenses as discussed above.

Cash flow used in investing activities

Net cash used in investing activities was $76.2 million during the three months ended March 31, 2014 as compared to net cash used in investing activities of $32.9 million during the three months ended March 31, 2013. The increase was primarily driven by an increase in capital expenditures resulting from our increased drilling program from four rigs in the first quarter of 2013 to ten rigs in the first quarter of 2014. The net cash used in investing for the three months ended March 31, 2014 was offset by $13.7 million in escrowed funds returned to us as a result of settled title negotiations.

Cash flow used in or provided by financing activities

Net cash provided by financing activities was $19.5 million during the three months ended March 31, 2014 as compared to net cash used in financing activities of $5.0 million during the three months ended March 31, 2013. The increase in cash flows provided by financing activities was primarily due to net borrowings of $20.0 million during

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the three months ended March 31, 2014 as compared to net repayments of $5.0 million during the three months ended March 31, 2013.

Contractual Obligations

There have been no material changes in our contractual obligations as reported in our Annual Report on Form 10-K for the year ended December 31, 2013.

Off-Balance Sheet Arrangements

We do not have any off-balance sheet arrangements.

Critical Accounting Policies and Estimates

There have been no changes to our critical accounting policies and estimates from those set forth in our Annual Report.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

The following market risk disclosures should be read in conjunction with the quantitative and qualitative disclosures about market risk contained in our Annual Report on Form 10-K for the year ended December 31, 2013, as well as with the unaudited consolidated financial statements and notes included in this Quarterly Report.

We are exposed to certain market risks that are inherent in our financial statements that arise in the normal course of business. We may enter into derivative instruments to manage or reduce market risk, but do not enter into derivative agreements for speculative purposes.

We do not designate these or future derivative instruments as hedges for accounting purposes. Accordingly, the changes in the fair value of these instruments are recognized currently in earnings.

Commodity price risk and hedges

Our principal market risk exposure is to oil, natural gas and NGL prices, which are inherently volatile. As such, future earnings are subject to change due to fluctuations in such prices. Realized prices are primarily driven by the prevailing prices for oil and regional spot prices for natural gas and NGLs. We have used, and expect to continue to use, oil, natural gas and NGL derivative contracts to reduce our risk of price fluctuations of these commodities. Pursuant to our risk management policy, we engage in these activities as a hedging mechanism against price volatility associated with projected production levels. The fair value of our oil, natural gas and NGL derivative contracts at March 31, 2014 was a net asset of $13.0 million.

As of March 31, 2014, we have hedged approximately 35% of our total forecasted production from proved reserves through 2018. The production hedged thereby is consistent with the anticipated monthly production levels in the December 31, 2013 reserve report. Actual production will vary from the amounts estimated in this reserve report, perhaps materially.

Counterparty and customer credit risk

Joint interest receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we drill. We are also subject to credit risk due to concentration of our oil and natural gas receivables with several significant customers. The inability or failure of these significant customers to meet their obligations or their insolvency or liquidation may adversely affect our financial results. In addition, our oil and natural gas derivative arrangements expose us to credit risk in the event of nonperformance by counterparties.

While we do not typically require our partners, customers and counterparties to post collateral and we do not have a formal process in place to evaluate and assess the credit standing of our partners or customers for oil and gas receivables and the counterparties on our derivative instruments, we do evaluate the credit standing of such parties as we deem appropriate under the circumstances. This evaluation may include reviewing a party s credit rating, latest financial information and, in the case of a customer with which we have receivables, their historical payment record, and undertaking the due diligence necessary to determine creditworthiness. The counterparties on our derivative instruments currently in place are lenders under the revolving credit facility with investment grade ratings. We are not permitted under the terms of the revolving credit facility to enter into derivative instruments with counterparties outside of the banks who are lenders under the revolving credit facility. As a result, any future derivative instruments will be with these or other lenders under the revolving credit facility who will also likely carry investment grade ratings.

Interest rate risk

We are subject to market risk exposure related to changes in interest rates on our indebtedness. The terms of the senior secured revolving credit facility and the second lien term loan provide for interest on borrowings at a floating rate equal to prime, LIBOR or federal funds rate plus margins ranging from 0.50% to 2.50% on the revolver and 6.0% to 7.0% on the term loan depending on the base rate used and the amount of the loan outstanding in relation to the borrowing base. During the three months ended March 31, 2014, borrowings under the senior secured revolving credit facility and second lien term loan bore interest at a weighted average rate of 2.87% and 9.13%, respectively.

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Item 4. Controls and Procedures

Changes in Internal Control over Financial Reporting

Prior to the completion of our initial public offering, we were a private company with limited accounting personnel to adequately execute our accounting processes and limited other supervisory resources with which to address our internal control over financial reporting. In previous years, we have not maintained an effective control environment in that the design and execution of our controls has not consistently resulted in effective review of our financial statements and supervision by appropriate individuals. The lack of adequate staffing levels resulted in insufficient time spent on review and approval of certain information used to prepare our financial statements. We concluded that these control deficiencies, although varying in severity, constitute a material weakness in our control environment.

Management has taken steps to address the causes of our audit adjustments and to improve our internal control over financial reporting, including the implementation of new accounting processes and control procedures and the identification of gaps in our skills base and expertise of the staff required to meet the financial reporting requirements of a public company. We have strengthened the accounting group, both in number and in caliber of personnel. This team has enabled us to expedite our month end close process, thereby facilitating the timely preparation of financial reports. Likewise, we strengthened our internal control environment through the addition of skilled accounting personnel. We continue to hire incremental qualified staff as needed in conjunction with a comprehensive review of our internal controls and formalization of our review and approval processes. We have designed but not fully implemented new processes and controls to remediate the material weakness identified. There have been no changes in internal control over financial reporting during the quarter ended March 31, 2014 that have materially affected, or are reasonably likely to materially affect, the Company s internal control over financial reporting.

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. In light of the previously identified material weakness described above and the insufficient time to test the operational effectiveness of our new processes and controls, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were not effective at the reasonable assurance level as of March 31, 2014.

Management s Assessment of Internal Control over Financial Reporting

The SEC, as required by Section 404 of the Sarbanes-Oxley Act, adopted rules requiring every public company that files reports with the SEC to include a management report on such company s internal control over financial reporting in its annual report. Pursuant to the Jumpstart Our Business Startups Act of 2012 (the JOBS Act), our independent registered public accounting firm will not be required to attest to the effectiveness of our internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002 for up to five years or through such earlier date that we are no longer an emerging growth company as defined in the JOBS Act. Our Annual Report on Form 10-K for the year ended December 31, 2013 did not include a report of management s assessment regarding internal control over financial reporting or an attestation report of our independent registered public accounting firm due to a transition period established by SEC rules applicable to newly public companies. Our management will be required to provide an assessment of the effectiveness of our internal control over financial reporting as of December 31, 2014.

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PART II OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of legal proceedings, see Note 9 to the Consolidated Financial Statements appearing in Part I, Item 1 of this Quarterly Report on Form 10-Q, which is incorporated in this item by reference.

Item 1A. Risk Factors

Our business faces many risks. Any of the risks discussed elsewhere in this Form 10-Q and our other SEC filings, including our Annual Report on Form 10-K for the year ended December 31, 2013, could have a material impact on our business, financial position or results of operations. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also impair our business operations.

With the exception of the following risk factor, there have been no material changes in our risk factors from those described in our Annual Report. For a discussion of our potential risks and uncertainties, see the information in Item 1A. Risk Factors in our Annual Report.

The presence of endangered or threatened species may force us to modify or terminate our operations in certain areas. Additionally, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or limit future development activity in the affected areas.

We conduct operations in areas where certain species that are listed as threatened or endangered under the Endangered Species Act (ESA) may be present. For example, our operations in Oklahoma overlap with the range of the American Burying Beetle, which is listed as endangered. The presence of endangered or threatened species may force us to modify or limit our operations in certain areas. Additionally, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or limit future development activity in the affected areas. For example, after lengthy consideration, the U.S. Fish and Wildlife Service determined to list the Lesser Prairie Chicken as a threatened species under the ESA on March 27, 2014. In a special rule released simultaneously with the decision to list the Lesser Prairie Chicken as threatened, the Fish and Wildlife Service will exempt from take certain oil and gas and other activities conducted by a participant that result in an incidental take of the Lesser Prairie Chicken as long as the participant is enrolled in, and operating in compliance with, a range wide conservation plan endorsed by the Fish and Wildlife Service. The rules become effective on May 12, 2014. We are continuing to evaluate the impact of these rules on our operations. As with any other species in areas that we operate, the listing of the Lesser Prairie Chicken under the ESA could force us to incur additional costs and delay or otherwise limit our operations in certain areas.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Not applicable.

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Item 6. Exhibits

Exhibit No.	Description
31.1*	Rule 13a-14(a)/15d-14(a) Certification of Jonny Jones (Principal Executive Officer).
31.2*	Rule 13a-14(a)/15d-14(a) Certification of Robert J. Brooks (Principal Financial Officer).
32.1**	Section 1350 Certification of Jonny Jones (Principal Executive Officer).
32.2**	Section 1350 Certification of Robert J. Brooks (Principal Financial Officer).
101.INS**	XBRL Instance Document.
101.SCH**	XBRL Taxonomy Extension Schema Document.
101.CAL**	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF**	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB**	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE**	XBRL Taxonomy Extension Presentation Linkbase Document.

* - filed herewith

** - furnished herewith

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SIGNATURES

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

Jones Energy, Inc.

(registrant)

Date: May 9, 2014	By:	/s/ Jonny Jones	
		Name:	Jonny Jones
		Title:	*Chief Executive Officer*

Signature Page to Form 10-Q (Q1 2014)