Jones Energy, Inc.
Form 10-Q
November 10, 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 September 30, 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 (Do not check if a smaller reporting company)	Smaller reporting company o

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

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On October 31, 2014, the Registrant had 12,648,242 shares of Class A common stock outstanding and 36,719,499 shares of Class B common stock outstanding.

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PART 1 FINANCIAL INFORMATION

Item 1. Financial Statements

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Jones Energy, Inc.

Consolidated Balance Sheets (Unaudited)

(in thousands of dollars)	September 30, 2014	December 31, 2013
Assets		
Current assets		
Cash	$ 32,790	$ 23,820
Restricted Cash	97	45
Accounts receivable, net		
Oil and gas sales	62,146	51,233
Joint interest owners	36,009	42,481
Other	2,313	16,782
Commodity derivative assets	13,077	8,837
Other current assets	3,120	2,392
Deferred tax assets		12
Total current assets	149,552	145,602
Oil and gas properties, net, at cost under the successful efforts method	1,533,704	1,297,228
Other property, plant and equipment, net	3,863	3,444
Commodity derivative assets	15,125	25,398
Other assets	18,950	15,006
Deferred tax assets		1,301
Total assets	$ 1,721,194	$ 1,487,979
Liabilities and Stockholders Equity		
Current liabilities		
Trade accounts payable	$ 118,687	$ 89,430
Oil and gas sales payable	73,343	66,179
Accrued liabilities	43,506	10,805
Commodity derivative liabilities	988	10,664
Deferred tax liabilities	68	
Asset retirement obligations	3,026	2,590
Total current liabilities	239,618	179,668
Long-term debt	270,000	658,000
Senior notes	500,000	
Deferred revenue	13,669	14,531
Commodity derivative liabilities	1,010	190
Asset retirement obligations	9,642	8,373
Deferred tax liabilities	8,348	3,093
Total liabilities	1,042,287	863,855
Commitments and contingencies (Note 9)		
Stockholders equity		
Class A common stock, $0.001 par value; 12,576,612 shares issued and 12,554,010 shares outstanding at September 30, 2014 and 12,526,580 shares issued and outstanding at December 31, 2013	13	13
Class B common stock, $0.001 par value; 36,813,731 shares issued and outstanding at September 30, 2014 and 36,836,333 shares issued and outstanding at December 31, 2013	37	37
Treasury stock, at cost: 22,602 Class A shares at September 30, 2014 and 0 shares at December 31, 2013	(358)	
Additional paid-in-capital	175,876	173,169
Retained earnings (deficit)	7,369	(2,186)
Stockholders equity	182,937	171,033
Non-controlling interest	495,970	453,091

Total stockholders equity		678,907		624,124
Total liabilities and stockholders equity	$	1,721,194	$	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 share data)	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Operating revenues				
Oil and gas sales	$ 99,707	$ 68,625	$ 303,370	$ 188,184
Other revenues	639	226	1,610	673
Total operating revenues	100,346	68,851	304,980	188,857
Operating costs and expenses				
Lease operating	11,244	7,761	33,635	19,308
Production taxes	4,983	3,469	14,919	9,103
Exploration	266	853	3,278	1,458
Depletion, depreciation and amortization	47,965	30,529	130,521	82,552
Accretion of discount	206	170	573	434
General and administrative (including non-cash compensation expense)	6,925	13,974	18,723	25,611
Total operating expenses	71,589	56,756	201,649	138,466
Operating income	28,757	12,095	103,331	50,391
Other income (expense)				
Interest expense	(11,849)	(7,148)	(34,659)	(23,427)
Net gain (loss) on commodity derivatives	41,163	(20,728)	(9,785)	4,444
Gain (loss) on sales of assets	30	(55)	97	(30)
Other income (expense), net	29,344	(27,931)	(44,347)	(19,013)
Income (loss) before income tax	58,101	(15,836)	58,984	31,378
Income tax provision (benefit)	5,871	(344)	6,550	(93)
Net income (loss)	52,230	(15,492)	52,434	31,471
Net income (loss) attributable to non-controlling interests	42,701	(14,623)	42,879	32,340
Net income (loss) attributable to controlling interests	$ 9,529	$ (869)	$ 9,555	$ (869)
Earnings per share:				
Basic	$ 0.76	$ (0.07)	$ 0.76	$ (0.07)
Diluted	$ 0.76	$ (0.07)	$ 0.76	$ (0.07)
Weighted average shares outstanding:				
Basic	12,508	12,500	12,503	12,500
Diluted	12,573	12,500	12,540	12,500

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)

	Common Stock				Treasury Stock		Additional			Total
	Class A		Class B		Class A		Paid-in-	Retained	Non-controlling	Stockholders
(amounts in thousands)	Shares	Value	Shares	Value	Shares	Value	Capital	Earnings	Interest	Equity
Balance at December 31, 2013	12,500	$ 13	36,836	$ 37		$	$ 173,169	$ (2,186)	$ 453,091	$ 624,124
Vested restricted shares	27									
Stock compensation expense							2,707			2,707
Exchange of Class B shares for Class A shares	23		(23)			0				
Treasury stock	(23)				23	(358)				(358)
Net income								9,555	42,879	52,434
Balance at September 30, 2014	12,527	$ 13	36,813	$ 37	23	$ (358)	$ 175,876	$ 7,369	$ 495,970	$ 678,907

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)	Nine Months Ended September 30, 2014	2013
Cash flows from operating activities		
Net income	$ 52,434	$ 31,471
Adjustments to reconcile net income to net cash provided by operating activities		
Dry hole costs	2,952	
Depletion, depreciation, and amortization	130,521	82,552
Accretion of discount	573	434
Amortization of debt issuance costs	6,129	2,003
Accrued interest expense	16,611	
Stock compensation expense	2,707	10,379
Other non-cash compensation expense	380	2,592
Amortization of deferred revenue	(862)	(114)
Net loss (gain) on commodity derivatives	9,785	(4,444)
(Gain) loss on sales of assets	(97)	30
Deferred income taxes	6,637	(141)
Other - net	241	227
Changes in assets and liabilities		
Accounts receivable	(4,961)	(23,359)
Other assets	631	643
Accounts payable and accrued liabilities	28,151	16,292
Net cash provided by operations	251,832	118,565
Cash flows from investing activities		
Additions to oil and gas properties	(343,405)	(127,478)
Net adjustments to purchase price of properties acquired	15,709	
Proceeds from sales of assets	99	629
Acquisition of other property, plant and equipment	(1,196)	(440)
Current period settlements of matured derivative contracts	(14,228)	7,680
Change in restricted cash	(52)	
Net cash used in investing	(343,073)	(119,609)
Cash flows from financing activities		
Proceeds from issuance of long-term debt	80,000	
Repayment under long-term debt	(468,000)	(172,000)
Proceeds from senior notes	500,000	
Proceeds from sale of common stock, net of expenses of $15.1 million		172,422
Purchases of treasury stock	(358)	
Payment of debt issuance costs	(11,431)	(49)
Net cash provided by financing	100,211	373
Net increase (decrease) in cash	8,970	(671)
Cash		
Beginning of period	23,820	23,726
End of period	$ 32,790	$ 23,055
Supplemental disclosure of cash flow information		
Cash paid for interest	$ 10,787	$ 19,442
Cash paid for income taxes	155	
Change in accrued additions to oil and gas properties	58,501	26,826
Current additions to ARO	1,205	499
Deferred offering costs		60
Noncash distribution to members		10,000

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, revised our Consolidated Statement of Operations for the three and nine months ended September 30, 2013 to record \$0.3 million and \$0.7 million, respectively, of additional interest expense on obligations that are unrelated to our credit agreements discussed in Note 6 Long-Term Debt .

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 transactions and balances have been eliminated in consolidation. The financial statements reported for September 30, 2014, and the three and nine-month periods then ended include the Company and all of its subsidiaries.

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Jones Energy, Inc.

Notes to the Consolidated Financial Statements (Unaudited)

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 September 30, 2014 and December 31, 2013:

(in thousands of dollars)	September 30, 2014	December 31, 2013
Mineral interests in properties		
Unproved	$ 103,482	$ 99,134
Proved	974,868	958,816
Wells and equipment and related facilities	955,570	609,748

		2,033,920		1,667,698
Less: Accumulated depletion and impairment		(500,216)		(370,470)
Net oil and gas properties	$	1,533,704	$	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 in assessing the reserves and the economic and operating viability of the project is being made. During the nine months ended September 30, 2014 we had no material capitalized costs associated with exploratory wells.

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Jones Energy, Inc.

Notes to the Consolidated Financial Statements (Unaudited)

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 nine months ended September 30, 2014 as no projects lasted more than six months. Depletion of oil and gas properties amounted to $47.7 million and $129.7 million for the three and nine months ended September 30, 2014, respectively, and $30.3 million and $81.9 million for the three and nine months ended September 30, 2013, respectively.

Other Property, Plant and Equipment

Other property, plant and equipment consisted of the following at September 30, 2014 and December 31, 2013:

(in thousands of dollars)	September 30, 2014	December 31, 2013
Leasehold improvements	$ 1,116	$ 1,060
Furniture, fixtures, computers and software	3,341	2,491
Vehicles	988	835
Aircraft	910	910
Other	219	134
	6,574	5,430
Less: Accumulated depreciation and amortization	(2,711)	(1,986)
Net other property, plant and equipment	$ 3,863	$ 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 $0.3 million and $0.8 million during the three and nine months ended September 30, 2014, respectively, and $0.2 million and $0.6 million during the three and nine months ended September 30, 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 nine month periods ended September 30, 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 (ARO) consist of future plugging and abandonment expenses on oil and natural gas properties.

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Jones Energy, Inc.

Notes to the Consolidated Financial Statements (Unaudited)

A summary of the Company s ARO for the nine months ended September 30, 2014 is as follows:

(in thousands of dollars)		
Balance at December 31, 2013	$	10,963
Liabilities incurred		1,205
Accretion of discount		573
Liabilities settled due to sale of related properties		(54)
Liabilities settled due to plugging and abandonment		(55)
Change in estimate		36
Balance at September 30, 2014		12,668
Less: Current portion of ARO		(3,026)
Total long-term ARO at September 30, 2014	$	9,642

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 Accounting Standards Codification (ASC) 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 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

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Jones Energy, Inc.

Notes to the Consolidated Financial Statements (Unaudited)

under the TRA. The Company will retain the benefit of the remaining 15% of the cash savings. Liabilities under the TRA will be recognized upon the exchange of shares. As of September 30, 2014, there had been no exchanges to date that resulted in a material liability.

Stock Compensation

JEH had a management incentive plan that provided 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 and will be fully vested at December 31, 2014. All grants awarded after the initial registration statement but prior to the IPO have a vesting structure of either three or 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.

In September 2013, the Company granted each of the four outside members of the Board of Directors 6,645 shares, and in September 2014, the Company granted each of the five outside members of the Board of Directors 5,486 shares of restricted Class A common stock under the Jones Energy, Inc. 2013 Omnibus Incentive Plan. The fair value of the restricted stock awards 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 relevant vesting periods.

In May 2014, the Company granted performance unit and restricted stock unit awards to certain officers and employees under the Jones Energy, Inc. 2013 Omnibus Incentive Plan. The fair value of the performance units was based on the grant date fair value (using a Monte Carlo simulation model) and is expensed on a straight-line basis over the applicable three-year performance period. The number of shares of common stock issuable upon vesting of the performance unit awards ranges from zero to 200% based on the Company s total shareholder return relative to an industry peer group over the applicable three-year performance period. The fair value of the restricted stock unit awards 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 applicable three-year vesting period.

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

Recent Accounting Pronouncements

We have considered all new accounting pronouncements and concluded there are no new pronouncements that may have a material impact on the results of operations, financial condition or cash flows, based on current information.

3. Acquisition of Properties

No property acquisitions that would qualify as a business combination occurred during the nine months ended September 30, 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 an initial 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.

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Jones Energy, Inc.

Notes to the Consolidated Financial Statements (Unaudited)

During the quarter ended June 30, 2014, the Company made a final determination with the sellers as to the purchase price resulting in a final purchase price of $179.2 million. The amount of the total purchase price allocated to undeveloped 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:

(in thousands of dollars)	Adjusted Purchase Price
Oil and gas properties	
Unproved	$ 32,964
Proved	147,024
Asset retirement obligations	(824)
Total purchase price	$ 179,164

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.

The unaudited pro forma results presented below have been prepared to give the effect of the acquisition on our results of operations for the three and nine months ended September 30, 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 September 30, 2013		Nine Months Ended September 30, 2013	
(in thousands of dollars)	Actual	Pro Forma	Actual	Pro Forma
Total operating revenue	$ 68,851	$ 81,408	$ 188,857	$ 228,780
Total operating expenses	56,756	65,428	138,466	166,262
Operating income	12,095	15,980	50,391	62,518
Net income (loss)	(15,492)	(11,607)	31,471	43,598
Earnings per share	$ (0.07)	$ (0.02)	$ (0.07)	$ (0.02)

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

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Jones Energy, Inc.

Notes to the Consolidated Financial Statements (Unaudited)

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 because 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 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 September 30, 2014 and December 31, 2013, by consolidated balance sheet caption and by valuation hierarchy, as described above are as follows:

	September 30, 2014 Fair Value Measurements			
(in thousands of dollars)	**(Level 1)**	**(Level 2)**	**(Level 3)**	**Total**
Commodity Price Hedges				
Current assets	$	$ 13,176	$ (99)	$ 13,077
Long-term assets		15,091	34	15,125
Current liabilities		712	276	988
Long-term liabilities		913	97	1,010

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Jones Energy, Inc.

Notes to the Consolidated Financial Statements (Unaudited)

(in thousands of dollars)	December 31, 2013 Fair Value Measurements (Level 1)	(Level 2)	(Level 3)	Total
Commodity Price Hedges				
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

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 September 30, 2014.

(fair value in thousands of dollars) Commodity Price Hedges	Fair Value	Quantitative Information About Level 3 Fair Value Measurements Valuation Technique	Unobservable Input	Range
Natural gas liquid swaps	$ (438)	Use a discounted cash flow approach using inputs including forward price statements from counterparties	Natural gas liquid futures prices	$6.72 - $72.52

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 nine months ended September 30, 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)	Level 3
Balance at December 31, 2013, net	$ (1,235)
Purchases	(390)
Settlements	
Transfers to Level 2	(74)
Transfers to Level 3	
Changes in fair value	1,261
Balance at September 30, 2014, net	$ (438)

Transfers from Level 3 to Level 2 represent all of the Company s natural gas liquids and basis swaps for which observable forward curve pricing information has become readily available. There were no transfers to Level 3 for the nine months ended September 30, 2014.

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

The following table provides the fair value of financial instruments that are not recorded at fair value in the consolidated financial statements:

(in thousands of dollars)	September 30, 2014 Carrying Amount	September 30, 2014 Fair Value	December 31, 2013 Carrying Amount	December 31, 2013 Fair Value
Debt:				
Revolver	$ 270,000	$ 270,000	$ 498,000	$ 498,000
Term Loan			160,000	160,000
2022 Notes	500,000	500,000		

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Jones Energy, Inc.

Notes to the Consolidated Financial Statements (Unaudited)

The Revolver (as defined in Note 6) is 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 approximates fair value, as it is subject to short-term floating interest rates that approximate the rates available to the Company for those periods.

The fair value of the 2022 Notes (as defined in Note 6) is based on pricing that is readily available in the public market. Accordingly, the 2022 Notes would be classified as Level 2 in the valuation hierarchy as the pricing is based on quoted market prices for similar debt securities in active markets.

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. 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. Accordingly, the fair value of oil and gas properties used in estimating impairment represents a nonrecurring Level 3 measurement. The Company assessed its unproved properties for impairment as of September 30, 2014 and no impairments were noted. In the event of an impairment, charges are recorded on the Consolidated Statement of Operations. No impairment charges on the Company s proved properties were recorded during the nine months ended September 30, 2014.

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 September 30, 2014 and December 31, 2013, as follows:

Hedging Positions

September 30, 2014

		Low	High	Weighted Average	Final Expiration
Oil swaps	Exercise price	$ 81.70	$ 101.53	$ 88.33	
	Barrels per month	29,000	179,589	86,747	December 2017
Natural gas swaps	Exercise price	$ 3.88	$ 6.90	$ 4.57	
	mmbtu per month	680,000	1,780,000	970,847	December 2018
Basis swaps	Contract differential	$ (0.43)	$ (0.11)	$ (0.31)	
	mmbtu per month	320,000	870,000	439,444	March 2016
Natural gas liquids swaps	Exercise price	$ 6.72	$ 95.24	$ 40.80	
	Barrels per month	2,000	171,000	57,487	December 2017

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Jones Energy, Inc.

Notes to the Consolidated Financial Statements (Unaudited)

		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 gain on derivative instruments of $41.2 million for the three months ended September 30, 2014, and a net loss of $9.8 million for the nine months ended September 30, 2014. The Company recognized a net loss on derivative instruments of $20.7 million for the three months ended September 30, 2013 and a net gain of $4.4 million for the nine months ended September 30, 2013.

Offsetting Assets and Liabilities

As of September 30, 2014, the counterparties to our commodity derivative contracts consisted of seven financial institutions as we entered into some contracts with a new counterparty during the current year. 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.

The following table presents information about our commodity derivative contracts that are netted on our Consolidated Balance Sheet as of September 30, 2014 and December 31, 2013:

(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
September 30, 2014					
Commodity derivative contracts					

Assets	$	31,781	$	(3,727)	$	28,054	$	148	$	28,202
Liabilities		(5,725)		3,727		(1,998)				(1,998)
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)

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Jones Energy, Inc.

Notes to the Consolidated Financial Statements (Unaudited)

6. Long-Term Debt

Senior Notes

On April 1, 2014, JEH and its wholly-owned subsidiary, Jones Energy Finance Corp. (the Issuers), sold $500.0 million in aggregate principal amount of the Issuers 6.75% Senior Notes due 2022 (the 2022 Notes). The Company used the net proceeds from the issuance of the 2022 Notes to repay all outstanding borrowings under the Term Loan ($160.0 million) and a portion of the borrowing under its Revolver ($308.0 million). The Company subsequently terminated its Term Loan in accordance with its terms. The 2022 Notes bear interest at a rate of 6.75% per year, payable semi-annually on April 1 and October 1 of each year beginning with October 1, 2014. As of September 30, 2014, the Company had $16.9 million in interest accrued related to the 2022 Notes.

The 2022 Notes are guaranteed on a senior unsecured basis by Jones Energy, Inc. and by all of its existing significant subsidiaries. The 2022 Notes will be senior in right of payment to any future subordinated indebtedness of the Issuers.

The Company may redeem the 2022 Notes at any time on or after April 1, 2017 at a declining redemption price set forth in the loan documents, plus accrued and unpaid interest.

The indenture governing the 2022 Notes contains covenants that limit the ability of the Company to incur additional indebtedness or issue certain preferred stock, pay dividends on capital stock, transfer or sell assets, make investments, create certain liens, enter into agreements that restrict dividends or other payments from the Company s restricted subsidiaries to the Company, consolidate, merge or transfer all of the Company s assets, engage in transactions with affiliates or create unrestricted subsidiaries. However, many of these covenants will be suspended if the Notes are rated investment grade by Standard & Poor s or Moody s.

Other 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). On April 1, 2014, the Term Loan was terminated in connection with the issuance of the 2022 Notes. On November 6, 2014, the Company amended the Revolver to, among other things, increase the borrowing base under the Revolver from $550.0 million to $625.0 million until the next redetermination thereof, and extend the maturity date of the Revolver to November 6, 2019. The Company s oil and gas properties are pledged as collateral for the outstanding borrowings under the Revolver.

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 and nine months ended September 30, 2014, the average interest rates under the Revolver were 2.17% and 2.54%, respectively, on average outstanding balances of $261.0 million and $334.6 million, respectively. For the same periods in 2013, the average interest rates were 2.74% and 3.04%, respectively, on average outstanding balances of $330.6 million and $406.7 million, respectively.

Total interest and commitment fees under the Revolver and Term Loan were $1.8 million and $10.3 million for the three and nine months ended September 30, 2014 and $6.2 million and $20.7 million for the three and nine months ended September 30, 2013. $3.8 million in unamortized deferred financing costs were written off to interest expense during the first half of 2014 in connection with the repayment of the Term Loan.

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Jones Energy, Inc.

Notes to the Consolidated Financial Statements (Unaudited)

7. Stock-based Compensation

Management Units

Prior to the IPO, JEH granted membership-interest awards in JEH to members of senior management (management units) under a previously existing management incentive plan. 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 September 30, 2014, there were 377,251 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 or forfeiture. The following table summarizes information related to the units/shares held by management as of September 30, 2014:

	JEH Units	Weighted Average Grant Date Fair Value per Share
Unvested at January 1, 2014	457,150	$ 12.46
Granted	4,772	15.00
Forfeited	(4,772)	15.00
Vested	(79,899)	15.00
Unvested at September 30, 2014	377,251	$ 11.92

Stock compensation expense associated with the management units amounted to $0.4 million and $1.2 million for the three and nine months ended September 30, 2014, respectively, and $9.9 million and $10.4 million for the three and nine months ended September 30, 2013, respectively, and is included in general and administrative expenses on the Company s Consolidated Statement of Operations.

Restricted Stock Awards

On September 23, 2014, the Company granted restricted stock awards to non-employee members of the Board of Directors. Each of the five directors was awarded 5,486 restricted shares of Class A common stock, contingent on the director serving as a director of the Company for the relevant service period. The fair value of the awards was based on the value of the Company s Class A common stock on the date of grant.

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. These awards fully vested in September 2014.

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Jones Energy, Inc.

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The total number of shares awarded to the directors is as follows:

Director Restricted Stock Awards

	Restricted Stock Awards		Weighted Average Grant Date Fair Value per Share
Unvested at January 1, 2014	26,580	$	15.05
Granted	27,430		18.77
Forfeited			
Vested	(26,580)		15.05
Unvested at September 30, 2014	27,430	$	18.77

Stock compensation expense associated with the Board of Directors awards for the three and nine months ended September 30, 2014 was $0.1 million and $0.3 million, respectively, and is included in general and administrative expenses on the Company s Consolidated Statement of Operations.

Restricted Stock Unit Awards

During the nine months ended September 30, 2014, the Company granted 303,929 restricted stock unit awards to certain officers and employees of the Company. The fair value of the restricted stock unit awards 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 applicable three-year vesting period. The total number of units awarded to the officers and employees is as follows:

Employee Restricted Stock Unit Awards

	Restricted Stock Unit Awards		Weighted Average Grant Date Fair Value per Share
Unvested at January 1, 2014		$	
Granted	303,929		17.17
Forfeited	(5,368)		17.07

Vested			
Unvested at September 30, 2014	298,561	$	17.18

Stock compensation expense associated with the employee restricted stock unit awards for the three and nine months ended September 30, 2014 was $0.4 million and $0.6 million, respectively, and is included in general and administrative expenses on the Company s Consolidated Statement of Operations.

Performance Unit Awards

During the nine months ended September 30, 2014, the Company granted 201,318 performance unit awards to certain officers of the Company. Upon the completion of the applicable three-year performance period, each officer will vest in a number of performance units. The number of performance units in which each officer vests at such time will range from 0% to 200% based on the Company s total shareholder return relative to an industry peer group over the applicable three-year performance period. Each vested performance unit is exchangeable for one share of the Company s Class A common stock. The grant date fair value of the performance units was determined using a Monte Carlo simulation model, which results in an expected percentage of performance units earned. The fair value of the performance units is recognized on a straight-line basis over the applicable three-year performance period.

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Jones Energy, Inc.

Notes to the Consolidated Financial Statements (Unaudited)

The total number of units awarded to the officers is as follows:

Employee Performance Unit Awards

	Performance Unit Awards	Weighted Average Grant Date Fair Value per Share	
Unvested at January 1, 2014		$	
Granted	201,318		21.65
Forfeited			
Vested			
Unvested at September 30, 2014	201,318	$	21.65

Stock compensation expense associated with the performance unit awards for the three and nine months ended September 30, 2014 was $0.4 million and $0.6 million, respectively, and is included in general and administrative expenses on the Company s Consolidated Statement of Operations.

The Monte Carlo simulation process is a generally accepted statistical technique used, in this instance, to simulate future stock prices for the Company and the components of the peer group. The simulation uses a risk-neutral framework along with the risk-free rate of return, the volatility of each entity, and the correlations of each entity with the other entities in the peer group. A stock price path has been simulated for the Company and each peer company and is used to determine the payout percentages and the stock price of the Company s common stock as of the vesting date. The ending stock price is multiplied by the payout percentage to determine the projected payout, which is then discounted with the risk-free rate of return to the grant date to determine the grant date fair value for that simulation. When enough simulations are generated, the resulting distribution gives a reasonable estimate of the range of future expected stock prices.

The following assumptions were used for the Monte Carlo simulation model to determine the grant date fair value and associated compensation expense during the three and nine months ended September 30, 2014:

Stock Price(1)	$	17.07
Beginning Average Stock Price(2)	$	14.78
Expected Volatility(3)		46.95%
Risk-Free Rate of Return(4)		0.61%

(1) Based on the closing price of Jones Energy, Inc. Class A common stock on May 20, 2014.

(2) Based on the 10 trading days as of the beginning of the performance period.

(3) Based on the average historical volatilities over the most recent 2.62-year period for the Company and each peer company using daily stock prices through May 20, 2014. The measurement period reflects the 2.62 years remaining in the performance period as of the grant date.

(4) Based on the yield curve of U.S. Treasury rates as of May 20, 2014.

Based on these assumptions, the Monte Carlo simulation model resulted in a simulated fair value of $21.65 based on an expected percentage of performance units earned of 126.80%.

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Jones Energy, Inc.

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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. Shares of Class B common stock are 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 potential dilutive effect of shares that could be issued by the Company in conjunction with stock awards that have been granted to directors and employees. In accordance with ASC 260, Earnings Per Share, awards of nonvested shares shall be considered outstanding as of the respective grant dates for purposes of computing diluted EPS even though the award is contingent upon vesting. For the three and nine months ended September 30, 2014, 201,318 relating to performance units were excluded from the calculation as they would have had an antidilutive effect. 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 and nine months ended September 30, 2014.

(in thousands, except share data)	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2014
Income (numerator):		
Net income attributable to controlling interests	$ 9,529	$ 9,555
Weighted-average shares (denominator):		
Weighted-average number of shares of Class A common stock - basic	12,508	12,503
Weighted-average number of shares of Class A common stock - diluted	12,573	12,540
Earnings per share:		
Basic	$ 0.76	$ 0.76
Diluted	$ 0.76	$ 0.76

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 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 and nine months ended September 30, 2014 was 10.1% and 11.1%, respectively. The effective rate differs from the statutory rate of 35% primarily due to net income allocated to the non-controlling interest, percentage depletion, state income taxes, and other permanent differences. On a year to date basis, the difference in effective rate between reported periods reflects differences in the composition of estimated income and the Company s tax expense in Texas.

The Company s income tax provision was an expense of \$5.9 million and \$6.6 million for the three and nine months ended September 30, 2014, respectively, and benefit of \$0.3 million and \$0.1 million for the three and nine months ended September 30, 2013, respectively. See the table below for the allocation of the

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Jones Energy, Inc.

Notes to the Consolidated Financial Statements (Unaudited)

income tax provision between the controlling and non-controlling interests. As of September 30, 2014, the Company did not have any uncertain tax positions requiring adjustments to its tax liability.

(in thousands of dollars)	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Jones Energy, Inc.	$ 5,197	$ (375)	$ 5,395	$ (375)
Non-controlling interest	674	31	1,155	282
Income tax provision (benefit)	$ 5,871	$ (344)	$ 6,550	$ (93)

The Company had deferred tax assets for its federal and state loss carryforwards at September 30, 2014 recorded in non-current 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 September 30, 2014, management determined that a valuation allowance was not required for the tax loss carryforwards as they are expected to be fully utilized before expiration.

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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, as well as the unaudited consolidated financial statements and related notes thereto presented in this Quarterly Report on Form 10-Q, our quarterly report on Form 10-Q for the quarter ended March 31, 2014, filed on May 9, 2014 with the Securities and Exchange Commission and our quarterly report on Form 10-Q for the quarter ended June 30, 2014, filed on August 8, 2014 with the Securities and Exchange Commission. 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. 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 over 25 years and applied our knowledge to the Arkoma basin since 2011. 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, to which we can apply our technical experience and operational excellence to increase proved reserves and production and deliver attractive economic rates of return. Our goal is to build value through a disciplined balance between developing our current inventory of 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. The Henry Hub natural gas 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.

Third Quarter 2014 Highlights:

- Average daily net production for the quarter was 24.5 MBoe/d

- Cleveland 20x3 frack trial wells have now produced on average 9,800 incremental barrels of oil through the first 300 days of production. Early indications from the new cemented sliding sleeve wells show oil production which is at or above the frack trial oil production curve.

- Leased an additional 6,924 net acres since June 30th providing approximately 50 additional Cleveland net drilling locations. Average leasehold acquisition cost for the year is less than $1,500 per net acre. Cleveland net drilling locations acquired year to date now total approximately 130, which is nearly double the number of budgeted locations to be drilled in 2014.

- Signed a 10 year oil gathering and transportation agreement to transport our oil to both Plains and Valero market points. The gathering system is expected to begin operations during the second quarter of 2015.

- Increased borrowing base on the Revolver from $550 to $625 million.

- Increased hedge positions for crude oil to 150% of proved developed producing (PDP) reserves in 2015 and roughly 200% in 2016. For both oil and natural gas, approximately 60% of forecasted production from proved reserves is hedged through year-end 2016.

Updated Capital Expenditures Outlook

In our Annual Report on Form10-K for the year ended December 31, 2013, we provided an overview of our 2014 capital expenditures budget, which was approximately $350 million, $310 million of which was expected to be used to drill and complete wells. In our press release announcing financial and operational results for the second quarter of 2014, we provided an update to the market regarding our capital expenditures for the full year 2014. The updated outlook reflects our new projected capital expenditure total of $460 million.

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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 September 30, 2014	2013	Change	Nine Months Ended September 30, 2014	2013	Change
Revenues:						
Oil	$ 60,553	$ 40,528	$ 20,025	$ 179,004	$ 104,777	$ 74,227
Natural gas	19,338	13,437	5,901	64,017	41,124	22,893
NGLs	19,816	14,660	5,156	60,349	42,283	18,066
Total oil and gas	99,707	68,625	31,082	303,370	188,184	115,186
Other	639	226	413	1,610	673	937
Total operating revenues	100,346	68,851	31,495	304,980	188,857	116,123
Costs and expenses:						
Lease operating	11,244	7,761	3,483	33,635	19,308	14,327
Production taxes	4,983	3,469	1,514	14,919	9,103	5,816
Exploration	266	853	(587)	3,278	1,458	1,820
Depletion, depreciation and amortization	47,965	30,529	17,436	130,521	82,552	47,969
Accretion of discount	206	170	36	573	434	139
General and administrative	6,925	13,974	(7,049)	18,723	25,611	(6,888)
Total costs and expenses	71,589	56,756	14,833	201,649	138,466	63,183
Operating income	28,757	12,095	16,662	103,331	50,391	52,940
Other income (expenses):						
Interest expense	(11,849)	(7,148)	(4,701)	(34,659)	(23,427)	(11,232)
Net gain (loss) on commodity derivatives	41,163	(20,728)	61,891	(9,785)	4,444	(14,229)
Gain (Loss) on sales of assets	30	(55)	85	97	(30)	127
Total other income (expense)	29,344	(27,931)	57,275	(44,347)	(19,013)	(25,334)
Income (Loss) before income tax	58,101	(15,836)	73,937	58,984	31,378	27,606
Income tax provision (benefit)	5,871	(344)	6,215	6,550	(93)	6,643
Net income (loss)	52,230	(15,492)	67,722	52,434	31,471	20,963
Net income (loss) attributable to non-controlling interests	42,701	(14,623)	57,324	42,879	32,340	10,539
Net income (loss) attributable to controlling interests	$ 9,529	$ (869)	$ 10,398	$ 9,555	$ (869)	$ 10,424
Net production volumes:						
Oil (MBbls)	639	401	238	1,869	1,126	743
Natural gas (MMcf)	5,812	4,418	1,394	16,371	12,822	3,549
NGLs (MBbls)	644	462	182	1,733	1,287	446
Total (MBoe)	2,252	1,599	653	6,331	4,550	1,781
Average net (Boe/d)	24,478	17,380	7,098	23,190	16,667	6,523
Average sales price, unhedged:						
Oil (per Bbl), unhedged	$ 94.76	$ 101.07	$ (6.31)	$ 95.78	$ 93.05	$ 2.73
Natural gas (per Mcf), unhedged	3.33	3.04	0.29	3.91	3.21	0.70
NGLs (per Bbl), unhedged	30.77	31.73	(0.96)	34.82	32.85	1.97
Combined (per Boe) realized, unhedged	44.27	42.92	1.35	47.92	41.36	6.56
Average sales price, hedged:						
Oil (per Bbl), hedged	$ 90.80	$ 89.40	$ 1.40	$ 89.51	$ 87.56	$ 1.95
Natural gas (per Mcf), hedged	3.82	3.87	(0.05)	4.06	3.99	0.07
NGLs (per Bbl), hedged	30.27	31.88	(1.61)	32.74	33.91	(1.17)
Combined (per Boe) realized, hedged	44.27	42.33	1.94	45.88	42.52	3.36
Average costs (per Boe):						
Lease operating	$ 4.99	$ 4.85	$ 0.14	$ 5.31	$ 4.24	$ 1.07
Production taxes	2.21	2.17	0.04	2.36	2.00	0.36
Depletion, depreciation and amortization	21.30	19.09	2.21	20.62	18.14	2.48
General and administrative	3.08	8.74	(5.66)	2.96	5.63	(2.67)

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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 our 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:

Jones Energy, Inc.

Management s Discussion and Analysis

EBITDAX

(in thousands of dollars)	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Reconciliation of EBITDAX to net income				
Net income (loss)	$ 52,230	$ (15,492)	$ 52,434	$ 31,471
Interest expense (excluding amortization of deferred financing costs)	11,002	6,473	28,530	21,424
Exploration expense	266	853	3,278	1,458
Income taxes	5,871	(344)	6,550	(93)
Amortization of deferred financing costs	847	675	6,129	2,003
Depreciation and depletion	47,965	30,529	130,521	82,552
Accretion expense	206	170	573	434
Other non-cash charges (benefits)	201	(83)	241	227
Stock compensation expense	1,321	9,906	2,707	10,379
Other non-cash compensation expense	127	127	380	2,592
Net loss (gain) on commodity derivatives	(41,163)	20,728	9,785	(4,444)

Current period settlements of matured derivative contracts		285		(943)		(12,610)	5,262
Amortization of deferred revenue		(336)		(114)		(862)	(114)
Loss (gain) on sales of assets		(30)		55		(97)	30
EBITDAX	$	78,792	$	52,540	$	227,559	$ 153,181

Adjusted net income and adjusted earnings per share are supplemental non-GAAP financial measures that are 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, non-cash compensation expense, and the write off of the net unamortized portion of capitalized loan costs that were associated with our Term Loan, which was paid off with the proceeds from the issuance of our 2022 Notes, which we consider to be a non-recurring event. We define adjusted earnings per share as adjusted net income divided by the weighted average shares outstanding. We believe adjusted net income and

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adjusted earnings per share 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 and adjusted earnings per share 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 and nine months ended September 30, 2014 and 2013, respectively.

(in thousands of dollars except per share data)	Three Months Ended September 30, 2014	Three Months Ended September 30, 2013	Nine Months Ended September 30, 2014	Nine Months Ended September 30, 2013
Net income (loss)	$ 52,230	$ (15,492)	$ 52,434	$ 31,471
Net (gain)/ loss on commodity derivatives	(41,163)	20,728	9,785	(4,444)
Current period settlements of matured derivative contracts	285	(943)	(12,610)	5,262
Non-cash stock compensation expense	1,321	9,906	2,707	10,379
Other non-cash compensation expense	127	127	380	2,592
Net unamortized capitalized loan costs associated with Term Loan			3,761	
Tax impact(1)	3,464	(1,239)	(444)	(1,239)
Adjusted net income	16,264	$ 13,087	56,013	$ 44,021
Adjusted net income attributable to non-controlling interests	13,273		45,818	
Adjusted net income attributable to controlling interests	$ 2,991		$ 10,195	

	Three Months Ended September 30, 2014	Nine Months Ended September 30, 2014
Earnings per share (basic)	$ 0.76	$ 0.76
Net (gain)/ loss on commodity derivatives	(0.83)	0.20
Current period settlements of matured derivative contracts		(0.26)
Non-cash stock compensation expense	0.03	0.06
Other non-cash compensation expense		0.01
Net unamortized capitalized loan costs associated with Term Loan		0.08
Tax impact	0.28	(0.03)
Adjusted earnings per share (basic)	$ 0.24	$ 0.82
Earnings per share (diluted)	$ 0.76	$ 0.76
Net (gain)/ loss on commodity derivatives	(0.83)	0.20
Current period settlements of matured derivative contracts		(0.26)
Impairment of oil and gas properties		
Non-cash stock compensation expense	0.02	0.05
Other non-cash compensation expense		0.01
Net unamortized capitalized loan costs associated with Term Loan		0.08
Tax impact	0.28	(0.03)
Adjusted earnings per share (diluted)	$ 0.23	$ 0.81
Effective tax rate on net income attributable to controlling interests	32.9%	32.9%

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Results of Operations - Three months ended September 30, 2014 as compared to the three months ended September 30, 2013

Oil and gas sales. Oil and gas sales increased $31.1 million, or 45.3%, to $99.7 million for the three months ended September 30, 2014, as compared to $68.6 million for the three months ended September 30, 2013. The increase is attributable to a 40.8% increase in production volumes, as the drop in realized crude oil price was offset by the increase in natural gas prices. Average daily production increased to 24,478 Boe per day for the three months ended September 30, 2014 from 17,380 Boe per day for the three months ended September 30, 2013 driven by increases in crude oil, natural gas and natural gas liquids production. We produced 639,000 barrels of crude oil during the three months ended September 30, 2014 as compared to 401,000 barrels of crude oil during the three months ended September 30, 2013, an increase of 59.4%. Natural gas production increased 31.6% from 4,418 MMcf for the three months ended September 30, 2013 to 5,812 MMcf for the three months ended September 30, 2014. The overall increase in production is a result of enhanced completion techniques and an increase in the number of producing wells stemming from continued drilling activity and the acquisition of 92 producing Sabine wells. The increase in oil production is attributable to an increased focus on drilling liquids-rich wells. In addition, NGLs experienced production increases of 39.4%. Average realized prices for each product, excluding the effects of derivatives, for the three months ended September 30, 2014 as compared to the three months ended September 30, 2013 were as follows: crude oil declined 6.2% from $101.07 to $94.76 per barrel, natural gas increased 9.5% from $3.04 to $3.33 per Mcf, and NGLs declined 3.0% from $31.73 to $30.77 per barrel.

Costs and expenses

Lease operating. Lease operating expenses increased $3.5 million, or 43.6%, to $11.2 million for the three months ended September 30, 2014, as compared to $7.8 million for the three months ended September 30, 2013. The increase in lease operating expenses is attributable to the increase in number of producing wells leading to the 40.8% increase in production volumes discussed above. On a per unit basis, lease operating expenses increased $0.14, or 2.9%, from $4.85 in third quarter of 2013 to $4.99 in the third quarter of 2014. The increase is attributable to increases in certain types of expenses such as pipeline and salt water disposal costs that are characteristic of the types of wells we have been drilling.

Production taxes. Production taxes increased by $1.5 million, or 42.9%, to $5.0 million for the three months ended September 30, 2014, as compared to $3.5 million for the three months ended September 30, 2013. Overall, production taxes increased in conjunction with the 45.3% increase in oil and gas sales. The average production tax rate for the current quarter decreased slightly from 5.1% to 5.0% from the third quarter of 2013.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $17.5 million, or 57.4%, to $48.0 million for the three months ended September 30, 2014, as compared to $30.5 million for the three months ended September 30, 2013. Depreciation, depletion and amortization increased from $19.09 per Boe in the third quarter of 2013 to $21.30 per Boe in the third quarter of 2014, or an increase of 11.6%. The increase was primarily the result of continued drilling activity, higher per-well drilling costs, and the addition of the Sabine properties at the end of 2013, which increased our total depreciable basis.

General and administrative. General and administrative expenses decreased by $7.1 million, or 50.7%, to $6.9 million for the three months ended September 30, 2014, as compared to $14.0 million for the three months ended September 30, 2013. In the third quarter of 2013, we recognized $9.6 million of stock compensation expense related to the immediate vesting of certain shares upon the Company s initial public offering date. Excluding this one-time, non-cash event, general and administrative expenses increased by $2.5 million, or 56.8%, for the three months ended September 30, 2014 as compared to the three months ended September 30, 2013. Of the $2.5 million, $0.9 million was attributable to an increase in other stock compensation expense resulting from the new long term incentive plan, under which the first awards were made in the second quarter of 2014. The remaining increase is attributable to the overall growth of the company, including an increase in employee headcount. Excluding the aforementioned non-cash expenses, general and administrative expense increased, on a per unit basis, from $2.75 per Boe for the three months ended September 30, 2013 to $3.08 for the three months ended September 30, 2014.

Interest expense. Interest expense increased by $4.7 million, or 66.2%, to $11.8 million for the three months ended September 30, 2014 as compared to $7.1 million for the three months ended September 30, 2013. The increase is

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primarily attributable to increased borrowings and the issuance of the 2022 Notes which were issued on April 1, 2014.

Net gain (loss) on commodity derivatives. Our net gain or loss on commodity derivatives increased from a net loss of $20.7 million during the three months ended September 30, 2013 to a net gain of $41.2 million during the three months ended September 30, 2014. The variance was driven by lower average crude oil prices ($94.76 for the third quarter of 2014, as compared to the average crude oil price of $101.07 for the third quarter of 2013), combined with lower average futures prices as of September 30, 2014 as compared to September 30, 2013 for oil.

Results of Operations - Nine months ended September 30, 2014 as compared to the nine months ended September 30, 2013

Oil and gas sales. Oil and gas sales increased $115.2 million, or 61.2%, to $303.4 million for the nine months ended September 30, 2014, as compared to $188.2 million for the nine months ended September 30, 2013. The increase is attributable to increases in production and prices for all three commodity streams. Average daily production increased 39.1% to 23,190 Boe per day for the nine months ended September 30, 2014 from 16,667 Boe per day for the nine months ended September 30, 2013 with the main driver being an increase in crude oil production, which specifically accounted for 60.0% of the total increase in oil and gas sales. We produced 1.9 million barrels of crude oil during the nine months ended September 30, 2014 as compared to 1.1 million barrels of crude oil during the nine months ended September 30, 2013. The overall increase in production is a result of enhanced completion techniques and an increase in the number of producing wells stemming from continued drilling and the acquisition of 92 producing Sabine wells. The increase in oil production is attributable to an increased focus on drilling oil-based wells. In addition, both natural gas and NGLs experienced production increases of more than 25%. Average prices for all three products increased in the nine months ended September 30, 2014 as compared to the nine months ended September 30, 2013. The average realized price of crude oil, natural gas and natural gas liquids, excluding the effects of derivatives, increased from $93.05 to $95.78 per barrel, $3.21 to $3.91 per Mcf, and $32.85 to $34.82 per barrel, respectively, for the nine months ended September 30, 2014 as compared to the nine months ended September 30, 2013.

Costs and expenses

Lease operating. Lease operating expenses increased $14.3 million, or 74.1% to $33.6 million for the nine months ended September 30, 2014, as compared to $19.3 million for the nine months ended September 30, 2013. The increase in lease operating expense is primarily attributable to the increase in number of producing wells leading to the 39.1% increase in production volumes discussed above. On a per unit basis, lease operating expenses increased $1.07, or 25.2%, from $4.24 in the first nine months of 2013 to $5.31 in the first nine months of 2014. The increase is partly driven by an increased focus on production-enhancing activities, including more compression, gas lift, and other stimulation efforts. An additional $0.16 of the per unit variance can be specifically attributed to an increase in ad valorem taxes which is due to the increase in the number of producing wells from new drilling in Texas. The remainder of the increase is explained through increases in certain types of expenses such as wellhead labor, pipeline and salt water disposal costs that are characteristic of the types of wells we have been drilling.

Production taxes. Production taxes increased by $5.8 million, or 63.7%, to $14.9 million for the nine months ended September 30, 2014, as compared to $9.1 million for the nine months ended September 30, 2013. Overall, production taxes increased in conjunction with the 61.2% increase in oil and gas sales. The average production tax rate for the nine months ended September 30, 2014 was 4.9% as compared to 4.8% for the nine months ended September 30, 2013.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $47.9 million, or 58.0%, to $130.5 million for the nine months ended September 30, 2014, as compared to $82.6 million for the nine months ended September 30, 2013. Depreciation, depletion and amortization increased from $18.14 per Boe in the first nine months of 2013 to $20.62 per Boe in the first nine months of 2014, or an increase of 13.7%. The increase was primarily the result of continued drilling activity, higher per-well drilling costs, and the addition of the Sabine properties at the end of 2013, which increased our total depreciable basis.

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General and administrative. General and administrative expenses decreased by $6.9 million, or 27.0%, to $18.7 million for the nine months ended September 30, 2014, as compared to $25.6 million for the nine months ended September 30, 2013. Non-cash compensation expense decreased by $9.9 million as there was a $9.6 million one-time charge in the prior year related to the immediate vesting of certain shares upon the Company s initial public offering and a $2.6 million one-time management distribution related to the Monarch incentive plan during the prior year. New non-cash long term incentive plan awards valued at $1.2 million implemented in 2014 partially offset these decreases. The decrease in non-cash items was offset by increases in other general administrative expenses that are attributable to the overall growth of the company including an increase in employee headcount. Excluding the aforementioned non-cash expenses, general and administrative expense increased $0.01, on a per unit basis, from $2.95 per Boe for the nine months ended September 30, 2013 to $2.96 per Boe for the nine months ended September 30, 2014. The increase in activity resulting from our increased drilling program, combined with the acquisition of the Sabine properties, increased production without a proportionate increase in general and administrative expenses.

Interest expense. Interest expense increased by $11.3 million, or 48.3%, to $34.7 million for the nine months ended September 30, 2014 as compared to $23.4 million for the nine months ended September 30, 2013. The increase is primarily attributable to increased borrowings and the issuance of the 2022 Notes on April 1, 2014.

Net gain (loss) on commodity derivatives. Our net gain or loss on commodity derivatives decreased from a net gain of $4.4 million during the nine months ended September 30, 2013 to a net loss of $9.8 million during the nine months ended September 30, 2014. The variance was driven by higher average crude oil and natural gas prices ($95.78 and $3.91 respectively) for the first nine months of 2014, as compared to the average crude oil and natural gas prices ($93.05 and $3.21, respectively) for the first nine months of 2013, combined with higher average futures prices as of September 30, 2014 as compared to September 30, 2013 for both commodities.

Liquidity and Capital Resources

Historically, our primary sources of liquidity have been private and public sales of our equity and debt, 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 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 Revolver, 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 September 30, 2014 reflects a working capital deficit as we use the available balance of the borrowing base under our Revolver to manage cash flow.

On April 1, 2014, we issued $500.0 million aggregate principal amount of 6.75% senior notes due 2022 at an offering price equal to 100% of par. We received net proceeds of approximately $489.0 million, of which $160.0 million was used to repay all of the outstanding borrowings under our Term Loan, with the remaining proceeds used to pay down borrowings under our Revolver. We subsequently terminated the Term Loan in accordance with its terms. For additional information regarding the terms of the 2022 Notes, see Note 6 to the Consolidated Financial Statements appearing in Part I, Item 1 of this Quarterly Report on Form 10-Q. As of September 30, 2014, we have $280.0 million of available borrowing capacity under the Revolver, which significantly enhances our liquidity and capital resources.

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 nine months ended September 30, 2014 and 2013:

	Nine Months Ended September 30,			
(in thousands of dollars)		**2014**		**2013**
Net cash provided by operating activities	$	251,832	$	118,565
Net cash used in investing activities		(343,073)		(119,609)
Net cash provided by financing activities		100,211		373
Net increase(decrease) in cash	$	8,970	$	(671)

Cash flow provided by operating activities

Net cash provided by operating activities was $251.8 million during the nine months ended September 30, 2014 as compared to net cash provided by operating activities of $118.6 million during the nine months ended September 30, 2013. The increase in operating cash flows was primarily due to the $115.2 million increase in oil and gas revenues during the nine months ended September 30, 2014 as compared to the nine months ended September 30, 2013, driven by a 39.1% increase in production between the two periods and increases in prices for all products. The increase in revenues was augmented by an increase in accounts payable and accrued liabilities which were also driven by the increase in drilling activity.

Cash flow used in investing activities

Net cash used in investing activities was $343.1 million during the nine months ended September 30, 2014 as compared to net cash used in investing activities of $119.6 million during the nine months ended September 30, 2013. The increase was primarily driven by an increase in capital expenditures resulting from our continued drilling program with eleven rigs operating at September 30, 2014.

Cash flow provided by financing activities

Net cash provided by financing activities was $100.2 million during the nine months ended September 30, 2014 as compared to net cash provided by financing activities of $0.4 million during the nine months ended September 30, 2013. We recorded proceeds of $489.0 million from the issuance of the 2022 Notes, net of costs, in the second quarter of 2014, which were offset by net repayments during the period of $388.0 million on the Revolver and Term Loan.

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 on Form 10-K for the year ended December 31, 2013.

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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 September 30, 2014 was a net asset of $26.2 million.

As of September 30, 2014, we have hedged approximately 60% of our total forecasted oil and natural gas production from proved reserves through year end 2016.

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 Revolver 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 depending on the base rate used and the amount of the loan outstanding in relation to the borrowing base.

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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 September 30, 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 September 30, 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 recently enacted 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

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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.

There have been no material changes in our risk factors from those described in our Annual Report and our Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2014 (our Second Quarter 10-Q). For a discussion of our potential risks and uncertainties, see the information in Item 1A. Risk Factors in our Annual Report and our Second Quarter 10-Q.

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

The following table reflects the Company s repurchase of its Class A common stock for the three months ended September 30, 2014:

	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs (1)	Aggregate Dollar Value of Shares Purchased	Approximate Dollar Value That May Yet Be Purchased Under Plans or Programs (1)
July 1, 2014 - July 30, 2014	304	$ 18.47	304	$ 5,615	$ 642,389
August 1, 2014 - August 31, 2014					
September 1, 2014 September 30, 2014					
Total purchases during quarter ended September 30, 2014	304	$ 18.47	304	$ 5,615	$ 642,389

(1) On April 28, 2014, the Board of Directors authorized the Company to repurchase up to $1,000,000 of its Class A common stock from certain employees of the Company (the Electing Employees) to permit the payment of certain tax withholding obligations. The repurchase plan may be suspended, modified or discontinued at any time, and the Company has no obligation to repurchase any amount of its common stock under the plan.

(2) On July 23, 2014, the Company issued an aggregate of 304 shares of Class A common stock, respectively, to Electing Employees in exchange for an equivalent number of membership interests in Jones Energy Holdings, LLC (the JEH LLC Units) and shares of Class B common stock held by such Electing Employees. This exchange (the Exchange) was made pursuant to and in accordance with the Exchange Agreement, dated July 29, 2013, included as Exhibit 10.3 to the Issuer s Current Report on Form 8-K filed July 30, 2013. Immediately following the Exchange, the shares of Class A common stock were purchased by the Company from the Electing Employees for cash at a purchase price equal to the closing price per share of Class A common stock on the New York Stock Exchange on July 23, 2014. These shares were previously reported as being beneficially owned by Jonny Jones solely as a result of his status as a member of JRJ Management Company, LLC, as the manager of Jones Energy Management, LLC and as the trustee of the managing member

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of JET 3 GP, LLC, which are the general partners of the entities that held these shares prior to the Exchange. However, the purchase of the Class A common stock by the Company from the Electing Employees and any future purchases of Class A common stock pursuant to the repurchase plan is for the sole benefit of the Company and the Electing Employees and no proceeds will go to Jonny Jones or any other director or executive officer of the Company other than the Electing Employees. The Exchange was exempt from registration pursuant to Section 4(2) of the Securities Act of 1933, as amended.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

On September 26, 2014, Jones Energy, LLC (JEL) and Monarch Oil Pipeline, LLC (Monarch Pipeline) entered into two crude oil gathering and transportation agreements whereby Monarch Pipeline agreed to construct, own and operate pipeline, trucking and appurtenant facilities capable of receiving, gathering and transporting JEL s crude oil production from specified, dedicated areas in Lipscomb and Hemphill Counties, Texas (the Dedicated Areas). One of the agreements provides for intrastate transportation of an initial committed volume of 5,000 barrels per day from the Dedicated Areas to delivery points at the Valero Energy Piper Station and at the Monarch Pipeline Lipscomb and Casey Stations, all of which are located in Lipscomb County, Texas. The other agreement provides for interstate transportation of an initial committed volume of 7,000 barrels per day from the Dedicated Areas and from the Monarch Pipeline Casey Station to a delivery point at the Plains Pipeline Reydon Station located in Roger Mills County, Oklahoma. Beginning in the fifth year of the term of each agreement and for each year thereafter, the committed volume under each agreement is subject to upward or downward adjustment based on JEL s crude oil deliveries during the prior year. JEL may also at any time deliver crude oil volumes in excess of its committed volumes if Monarch Pipeline is able to receive such excess crude oil volumes. Both agreements have primary terms of 10 years that automatically extend for one year periods until either JEL or Monarch Pipeline terminates the agreements. The entire Monarch Pipeline system is expected to begin operations during the second quarter of 2015.

Monarch Pipeline is an affiliate of Monarch Natural Gas, LLC (Monarch). As of September 30, 2014, Metalmark Capital owned approximately 76% of the outstanding equity interests of Monarch. In addition, Metalmark Capital beneficially owns in excess of five percent of the Company s outstanding equity interests and two of the Company s directors, Howard I. Hoffen and Gregory D. Myers, are managing directors of Metalmark Capital.

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Item 6. Exhibits

Exhibit No.	Description
10.1*	Master Assignment, Agreement and Amendment No. 9 to Credit Agreement dated as of November 5, 2014, among Jones Energy Holdings, LLC, as borrower, Jones Energy, Inc., Jones Energy, LLC and Nosley Assets, LLC, as guarantors, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto.
10.2*	Firm Crude Oil Gathering and Transportation Agreement, dated September 26, 2014, by and between Monarch Oil Pipeline, LLC and Jones Energy, LLC.
10.3*	Gathering and Transportation Services Agreement, dated as of September 26, 2014, by and between Monarch Oil Pipeline, LLC and Jones Energy, LLC.
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: November 10, 2014	By:	/s/ Jonny Jones	
		Name:	Jonny Jones
		Title:	*Chief Executive Officer*