Jones Energy, Inc.
Form 10-Q
August 05, 2016
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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 June 30, 2016

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 x
Non-accelerated filer o (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

On July 29, 2016, the Registrant had 32,819,222 shares of Class A common stock outstanding and 29,872,426 shares of Class B common stock outstanding.

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JONES ENERGY, INC.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This report contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical facts, included in this report that address activities, events or developments that the Company expects, believes or anticipates will or may occur in the future are forward-looking statements. Without limiting the generality of the foregoing, forward-looking statements contained in this report specifically include the expectations of plans, strategies, objectives and anticipated financial and operating results of the Company, including guidance regarding the timing and location of our anticipated drilling and completion activity, our ability to increase capital spending in connection with leasing, our ability to mitigate commodity price risk through our hedging program, our revised 2016 capital expenditure program, our ability to fund the revised 2016 capital budget largely with free cash flow, our ability to close the pending acquisition of assets in the Anadarko basin and the expected benefits from such acquisition, and our ability to successfully execute our 2016 development plan and guidance for the remaining quarters and full year 2016. These statements are based on certain assumptions made by the Company based on management s experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include, but are not limited to, changes in prices for oil, natural gas liquids, and natural gas prices, weather, including its impact on oil and natural gas demand and weather-related delays on operations, the amount, nature and timing of planned capital expenditures, availability and method of funding acquisitions and divestitures, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, customers elections to reject ethane and include it as part of the natural gas stream, ability to fund our 2016 capital expenditure budget, the proximity to and capacity of transportation facilities, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting the Company s business and other important factors that could cause actual results to differ materially from those projected as described in the Company s reports filed with the SEC.

Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

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PART 1 FINANCIAL INFORMATION

Item 1. Financial Statements

Jones Energy, Inc.

Consolidated Balance Sheets (Unaudited)

(in thousands of dollars)	June 30, 2016	December 31, 2015
Assets		
Current assets		
Cash	$ 59,298	$ 21,893
Accounts receivable, net		
Oil and gas sales	18,397	19,292
Joint interest owners	4,701	11,314
Other	11,093	15,170
Commodity derivative assets	63,051	124,207
Other current assets	2,648	2,298
Total current assets	159,188	194,174
Oil and gas properties, net, at cost under the successful efforts method	1,580,248	1,635,766
Other property, plant and equipment, net	3,281	3,873
Commodity derivative assets	60,920	93,302
Other assets	7,365	8,039
Total assets	$ 1,811,002	$ 1,935,154
Liabilities and Stockholders Equity		
Current liabilities		
Trade accounts payable	$ 18,940	$ 7,467
Oil and gas sales payable	25,224	32,408
Accrued liabilities	23,456	27,341
Commodity derivative liabilities	1,359	11
Asset retirement obligations	679	679
Total current liabilities	69,658	67,906
Long-term debt	729,856	837,654
Deferred revenue	10,176	11,417
Commodity derivative liabilities	1,978	
Asset retirement obligations	21,015	20,301
Liability under tax receivable agreement	38,064	38,052
Deferred tax liabilities	19,837	22,972
Total liabilities	890,584	998,302
Commitments and contingencies (Note 13)		
Stockholders equity		
Class A common stock, $0.001 par value; 31,266,437 shares issued and 31,243,835 shares outstanding at June 30, 2016 and 30,573,509 shares issued and 30,550,907 shares outstanding at December 31, 2015	32	31
Class B common stock, $0.001 par value; 31,230,213 shares issued and outstanding at June 30, 2016 and 31,273,130 shares issued and outstanding at December 31, 2015	31	31
Treasury stock, at cost: 22,602 shares at June 30, 2016 and December 31, 2015	(358)	(358)
Additional paid-in-capital	368,306	363,723

Retained earnings		32,235		36,569
Stockholders equity		400,246		399,996
Non-controlling interest		520,172		536,856
Total stockholders equity		920,418		936,852
Total liabilities and stockholders equity	$	1,811,002	$	1,935,154

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

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Jones Energy, Inc.

Consolidated Statements of Operations (Unaudited)

(in thousands of dollars except per share data)	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Operating revenues				
Oil and gas sales	$ 28,398	$ 53,222	$ 53,478	$ 110,456
Other revenues	746	695	1,524	1,557
Total operating revenues	29,144	53,917	55,002	112,013
Operating costs and expenses				
Lease operating	7,545	11,796	16,162	24,058
Production and ad valorem taxes	1,727	3,071	3,328	6,779
Exploration	77	464	239	628
Depletion, depreciation and amortization	38,137	51,302	79,899	103,385
Accretion of ARO liability	297	206	590	400
General and administrative	8,126	9,433	15,630	17,944
Other operating		1,176		4,188
Total operating expenses	55,909	77,448	115,848	157,382
Operating income (loss)	(26,765)	(23,531)	(60,846)	(45,369)
Other income (expense)				
Interest expense	(12,807)	(16,702)	(27,605)	(30,831)
Gain on debt extinguishment	8,878		99,530	
Net gain (loss) on commodity derivatives	(40,002)	(25,075)	(22,783)	21,231
Other income (expense)	(338)	675	(113)	(1,624)
Other income (expense), net	(44,269)	(41,102)	49,029	(11,224)
Income (loss) before income tax	(71,034)	(64,633)	(11,817)	(56,593)
Income tax provision (benefit)	(12,388)	(13,453)	(1,685)	(11,109)
Net income (loss)	(58,646)	(51,180)	(10,132)	(45,484)
Net income (loss) attributable to non-controlling interests	(35,401)	(32,737)	(5,798)	(29,229)
Net income (loss) attributable to controlling interests	$ (23,245)	$ (18,443)	$ (4,334)	$ (16,255)
Earnings (loss) per share:				
Basic	$ (0.75)	$ (0.66)	$ (0.14)	$ (0.70)
Diluted	$ (0.75)	$ (0.66)	$ (0.14)	$ (0.70)
Weighted average shares outstanding:				
Basic	30,897	27,904	30,724	23,131
Diluted	30,897	27,904	30,724	23,131

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

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Jones Energy, Inc.

Statement of Changes in Stockholders Equity (Unaudited)

	Common Stock				Treasury Stock					
	Class A		Class B		Class A		Additional Paid-in	Retained (Deficit)/	Non-controlling	Total Stockholders
(amounts in thousands)	Shares	Value	Shares	Value	Shares	Value	Capital	Earnings	Interest	Equity
Balance at December 31, 2015	30,551	$ 31	31,273	$ 31	23	$ (358)	$ 363,723	$ 36,569	$ 536,856	$ 936,852
Stock-compensation expense							3,084			3,084
Vested restricted shares	369									
Distributions from partnership									(10,109)	(10,109)
Sale of common stock	281	1					1,055			1,056
Exchange of Class B shares for Class A shares	43		(43)				444		(777)	(333)
Net income (loss)								(4,334)	(5,798)	(10,132)
Balance at June 30, 2016	31,244	$ 32	31,230	$ 31	23	$ (358)	$ 368,306	$ 32,235	$ 520,172	$ 920,418

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)	Six Months Ended June 30, 2016	2015
Cash flows from operating activities		
Net income (loss)	$ (10,132)	$ (45,484)
Adjustments to reconcile net income (loss) to net cash provided by operating activities		
Depletion, depreciation, and amortization	79,899	103,385
Exploration (dry hole and lease abandonment)	27	
Accretion of ARO liability	590	400
Amortization of debt issuance costs	2,107	2,159
Stock compensation expense	3,084	3,248
Deferred and other non-cash compensation expense	401	218
Amortization of deferred revenue	(1,241)	(1,028)
(Gain) loss on commodity derivatives	22,783	(21,231)
(Gain) loss on sales of assets	1	6
(Gain) on debt extinguishment	(99,530)	
Deferred income tax provision	(3,291)	(11,109)
Other - net	949	760
Changes in operating assets and liabilities		
Accounts receivable	11,353	47,947
Other assets	(482)	995
Accrued interest expense	(4,201)	8,368
Accounts payable and accrued liabilities	3,683	(15,291)
Net cash provided by operations	6,000	73,343
Cash flows from investing activities		
Additions to oil and gas properties	(27,592)	(229,060)
Proceeds from sales of assets	5	21
Acquisition of other property, plant and equipment (net of reimbursements)	12	(382)
Current period settlements of matured derivative contracts	77,622	67,646
Net cash provided by / (used in) investing	50,047	(161,775)
Cash flows from financing activities		
Proceeds from issuance of long-term debt	75,000	75,000
Repayment under long-term debt		(335,000)
Proceeds from senior notes		236,475
Purchase of senior notes	(84,589)	
Payment of debt issuance costs		(1,513)
Net distributions paid to JEH unitholders	(10,109)	
Proceeds from sale of common stock	1,056	122,779
Net cash (used in) / provided by financing	(18,642)	97,741
Net increase (decrease) in cash	37,405	9,309
Cash		
Beginning of period	21,893	13,566
End of period	$ 59,298	$ 22,875
Supplemental disclosure of cash flow information		
Cash paid for interest	$ 29,700	$ 19,517
Change in accrued additions to oil and gas properties	1,980	(100,927)

Current additions to ARO	81	931

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, the Company 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 (collectively, the Pre-IPO Owners). 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.

The Company s certificate of incorporation authorizes two classes of common stock, Class A common stock and Class B common stock. The Class B common stock is held by the owners of JEH prior to the Company s initial public offering (IPO) and can be exchanged (together with a corresponding number of units representing membership interests in JEH (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 holders to one vote on all matters to be voted on by the Company s stockholders generally. As a result of the IPO and as of June 30, 2016, the Pre-IPO Owners had 74.7% and 50.0%, respectively, 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 exploration, development, production and acquisition of oil and natural gas properties in the mid-continent United States. The Company s assets are located within the Anadarko and Arkoma basins of Texas and Oklahoma, and are owned by JEH and its operating subsidiaries. The Company is headquartered in Austin, Texas.

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 Company s financial position as of December 31, 2015 and the financial statements reported for June 30, 2016 and 2015 and the three and six month periods then ended include the Company and all of its subsidiaries.

Certain prior period amounts have been reclassified to conform to the current presentation.

These interim financial statements have not been audited. However, in the opinion of management, all adjustments necessary for a fair statement of the financial statements have been included, and all such adjustments are of a normal, reoccurring nature. 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, 2015.

Use of Estimates

There have been no significant changes in our use of estimates since those reported in Jones Energy, Inc. s Annual Report on Form 10-K for the year ended December 31, 2015.

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Recent Accounting Pronouncements

Adopted in the current year-to-date period:

In January 2015, the FASB issued ASU No. 2015-01, Income Statement Extraordinary and Unusual Items. This ASU removes the concept of extraordinary items from GAAP. Under existing guidance, an entity is required to separately disclose extraordinary items, net of tax, in the income statement after income from continuing operations if an event or transaction is of an unusual nature and occurs infrequently. This separate, net of tax presentation will no longer be allowed. The amendments are effective for interim and annual reporting periods beginning after December 15, 2015. Therefore, the Company has adopted ASU No. 2015-01 for the period ended March 31, 2016. Adoption did not have a material impact on the financial position, cash flows or results of operations.

In April 2015, the FASB issued ASU No. 2015-03, Interest Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs. Entities that have historically presented debt issuance costs as an asset, related to a recognized debt liability, will be required to present those costs as a direct deduction from the carrying amount of that debt liability. The ASU does not change the recognition, measurement, or subsequent measurement guidance for debt issuance costs. Adoption of this ASU will be applied retrospectively. In August 2015, the FASB issued ASU No. 2015-15, Interest Imputation of Interest (Subtopic 835-30), which addresses the presentation or subsequent measurement of debt issuance costs related to line-of-credit arrangements, given the absence of authoritative guidance within ASU No. 2015-03 for debt issuance costs related to line-of-credit arrangements. The amendments are effective for interim and annual reporting periods beginning after December 15, 2015. Therefore, the Company adopted ASU No. 2015-03 beginning with the period ended March 31, 2016. Changes to the balance sheet have been applied on a retrospective basis. This resulted in the reclassification of debt issuance costs of $10.3 million from Other assets to Long-term debt in the Consolidated Balance Sheet for the period ended December 31, 2015. Adoption did not have a material impact on the financial position, cash flows or results of operations.

To be adopted in a future period:

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU) No. 2014-09, Revenue from Contracts with Customers, which creates a new topic in the ASC, topic 606, Revenue from Contracts with Customers. This ASU sets forth a five-step model for determining when and how revenue is recognized. Under the model, an entity will be required to recognize revenue to depict the transfer of goods or services to a customer at an amount reflecting the consideration it expects to receive in exchange for those goods or services. Additional disclosures will be required to describe the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts. In August 2015, the FASB issued ASU 2015-14 which deferred the effective date of ASU 2014-09 by one year. The amendments are now effective for interim and annual reporting periods beginning after December 15, 2017 and may be applied on either a full or modified retrospective basis. Early adoption is permitted. The Company is currently evaluating the effect that the adoption of Update 2014-09 and Update 2015-14 will have on our financial statements.

In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842). This amendment requires, among other things, that lessees recognize the following for all leases (with the exception of short-term leases) at the commencement date: (1) a lease liability, which is a lessee s obligation to make lease payments arising from a lease, measured on a discounted basis; and (2) a right-of-use asset, which is an asset that represents the lessee s right to use, or control the use of, a specified asset for the lease term. Lessees and lessors must apply a modified retrospective transition approach for leases existing at, or entered into after, the beginning of the earliest comparative period presented in the financial statements. The amendments are effective for interim and annual reporting periods beginning after December 15, 2018. The Company is currently evaluating the impacts of the amendments to our financial statements and accounting practices for leases.

In March 2016, the FASB issued ASU 2016-09, Compensation Stock Compensation (Topic 718). This amendment is intended to simplify the accounting for share-based payment awards to employees, specifically in regard to (1) the income tax consequences, (2) classification of awards as either equity or liabilities, and (3) classification on the statement of cash flows. The amendments are effective for interim and annual reporting periods beginning after December 15, 2016. Early adoption is permitted. The Company is currently evaluating the effect that the adoption of ASU 2016-09 will have on our financial statements.

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3. Properties, Plant and Equipment

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 June 30, 2016 and December 31, 2015:

(in thousands of dollars)		June 30, 2016		December 31, 2015
Mineral interests in properties				
Unproved	$	73,712	$	75,308
Proved		1,036,356		1,031,669
Wells and equipment and related facilities		1,310,060		1,289,323
		2,420,128		2,396,300
Less: Accumulated depletion and impairment		(839,880)		(760,534)
Net oil and gas properties	$	1,580,248	$	1,635,766

There were no exploratory wells drilled or completed during the six months ended June 30, 2016 and 2015, and as such, no associated costs were capitalized.

The Company did not capitalize any interest during the six months ended June 30, 2016 as no projects lasted more than six months. Costs incurred to maintain wells and related equipment are charged to expense as incurred.

Depletion of oil and gas properties amounted to $37.8 million and $79.3 million for the three and six months ended June 30, 2016, respectively, and $51.0 million and $102.8 million for the three and six months ended June 30, 2015, respectively.

Due to the decline in forward commodity prices in early 2016, the Company continues to monitor its proved and unproved properties for impairment as of June 30, 2016. No impairment charges were recorded.

Other Property, Plant and Equipment

Other property, plant and equipment consisted of the following at June 30, 2016 and December 31, 2015:

(in thousands of dollars)	June 30, 2016	December 31, 2015
Leasehold improvements	$ 1,213	$ 1,260
Furniture, fixtures, computers and software	4,121	4,090
Vehicles	1,537	1,537
Aircraft	910	910
Other	252	247
	8,033	8,044
Less: Accumulated depreciation and amortization	(4,752)	(4,171)
Net other property, plant and equipment	$ 3,281	$ 3,873

Depreciation and amortization of other property, plant and equipment amounted to $0.3 million and $0.6 million for the three and six months ended June 30, 2016, respectively, and $0.3 million and $0.6 million for the three and six months ended June 30, 2015, respectively.

4. Long-Term Debt

Long-term debt consisted of the following at June 30, 2016 and December 31, 2015:

(in thousands of dollars)	June 30, 2016	December 31, 2015
Revolver	$ 185,000	$ 110,000
2022 Notes	409,148	500,000
2023 Notes	150,000	250,000
Total principal amount	744,148	860,000
Less: unamortized discount	(6,747)	(12,088)
Less: debt issuance costs, net	(7,545)	(10,258)
Total carrying amount	$ 729,856	$ 837,654

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Senior Unsecured Notes

On April 1, 2014, JEH and Jones Energy Finance Corp., JEH s wholly owned subsidiary formed for the sole purpose of co-issuing certain of JEH s debt (together 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), a portion of the outstanding borrowings under the Revolver ($308.0 million) and for working capital and general corporate purposes. The Company subsequently terminated the 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 October 1, 2014. The 2022 Notes were registered in March 2015.

On February 23, 2015, the Issuers sold $250.0 million in aggregate principal amount of 9.25% senior notes due 2023 (the 2023 Notes) in a private placement to affiliates of GSO Capital Partners LP and Magnetar Capital LLC. The 2023 Notes were issued at a discounted price equal to 94.59% of the principal amount. The Company used the $236.5 million net proceeds from the issuance of the 2023 Notes to repay outstanding borrowings under the Revolver and for working capital and general corporate purposes. The 2023 Notes bear interest at a rate of 9.25% per year, payable semi-annually on March 15 and September 15 of each year beginning September 15, 2015. The 2023 Notes were registered in February 2016.

During the six months ended June 30, 2016, through several open market and privately negotiated purchases, the Company purchased an aggregate principal amount of $190.9 million of its senior unsecured notes. As of June 30, 2016, the Company had purchased $90.9 million principal amount of its 2022 Notes for $38.1 million, and $100.0 million principal amount of its 2023 Notes for $46.5 million, in each case excluding accrued interest and including any associated fees. The Company used cash on hand and borrowings from its Revolver to fund the note purchases. In conjunction with the extinguishment of this debt, JEH recognized cancellation of debt income of $8.9 and $99.5 million for the three and six months ended June 30, 2016, respectively, on a pre-tax basis. This income is recorded in Gain on debt extinguishment on the Company s Consolidated Statement of Operations. Of the Company s total repurchases, $20.3 million principal amount of its 2022 Notes were not cancelled and are available for future reissuance, subject to applicable securities laws.

The 2022 Notes and 2023 Notes are guaranteed on a senior unsecured basis by the Company and by all of its significant subsidiaries. The 2022 Notes and 2023 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 and the 2023 Notes at any time on or after March 15, 2018 at a declining redemption price set forth in the respective indentures, plus accrued and unpaid interest.

The indentures governing the 2022 Notes and 2023 Notes are substantially identical and contain covenants that, among other things, 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. If at any time when the 2022 Notes or 2023 Notes are rated investment grade and no default or event of default (as defined in the indenture) has occurred and is continuing, many of the foregoing covenants pertaining to the 2022 Notes or 2023 Notes, as applicable, will be suspended. If the ratings on the 2022 Notes or 2023 Notes, as applicable, were to decline subsequently to below investment grade, the suspended covenants would be reinstated.

As of June 30, 2016, the Company was in compliance with the indentures governing the 2022 Notes and 2023 Notes.

Other Long-Term Debt

The Company entered into two credit agreements dated December 31, 2009, with Wells Fargo Bank N.A, the Senior Secured Revolving Credit Facility (the Revolver) and the Second Lien Term Loan (the Term Loan), each of which has been amended. On April 1, 2014, the Term Loan was repaid in full and terminated in connection with the issuance of the 2022 Notes. On November 6, 2014, the Company amended the Revolver to extend the maturity date of the Revolver to November 6, 2019. The Company s oil and gas properties are pledged as collateral to secure its obligations under the Revolver. The borrowing base on the Revolver was subsequently adjusted to $562.5 million in accordance with its terms as a result of the issuance of the 2023 Notes in February 2015 and was reaffirmed at this level effective April 1, 2015. Effective October 8,

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2015, the borrowing base was reduced to $510 million during the semi-annual borrowing base re-determination. On August 1, 2016, the Company entered into an amendment to the Revolver. See Note 14, Subsequent Events for further details of this amendment. Pursuant to the amendment to the Revolver, the borrowing base on the Revolver was set at $410.0 million effective immediately, with an increase to $425.0 million upon closing of our executed Purchase and Sale Agreement to acquire producing and undeveloped oil and gas assets in the Anadarko Basin (the Pending Anadarko Acquisition).

The terms of the Revolver require the Company to make periodic payments of interest on the loans outstanding thereunder, with all outstanding principal and interest under the Revolver due on the maturity date. The Revolver is subject to a borrowing base which limits the amount of borrowings which may be drawn thereunder. The borrowing base will be re-determined by the lenders at least semi-annually on or about April 1 and October 1 of each year, with such re-determination based primarily on reserve reports using lender commodity price expectations at such time. Any reduction in the borrowing base will reduce our liquidity, and, if the reduction results in the outstanding amount under our revolving credit facility exceeding the borrowing base, we will be required to repay the deficiency within a short period of time.

Interest on the Revolver is calculated, at the Company s option, at either (a) the London Interbank Offered (LIBO) rate for the applicable interest period plus a margin of 1.50% to 2.50% based on the level of borrowing base utilization at such time or (b) the greatest of the federal funds rate plus 0.50%, the one month adjusted LIBO rate plus 1.00%, or the prime rate announced by Wells Fargo Bank, N.A. in effect on such day, in each case plus a margin of 0.50% to 1.50% based on the level of borrowing base utilization at such time. For the three and six months ended June 30, 2016, the average interest rates under the Revolver were 2.25% and 2.43%, respectively, on average outstanding balances of $185.0 million and $164.0 million, respectively. For the three and six months ended June 30, 2015, the average interest rates under the Revolver were 2.35% and 2.43%, respectively, on average outstanding balances of $100.0 million and $185.5 million, respectively.

Total interest and commitment fees under the Revolver were $1.3 million and $2.6 million for the three and six months ended June 30, 2016, respectively, and $1.0 million and $3.0 million for the three and six months ended June 30, 2015, respectively.

Jones Energy, Inc. and its consolidated subsidiaries are subject to certain covenants under the Revolver, including the requirement to maintain the following financial ratios:

- a total leverage ratio, consisting of consolidated debt to EBITDAX, of not greater than 4.00 to 1.00 as of the last day of any fiscal quarter; and

- a current ratio, consisting of consolidated current assets, including the unused amounts of the total commitments, to consolidated current liabilities, of not less than 1.0 to 1.0 as of the last day of any fiscal quarter.

As of June 30, 2016, our total leverage ratio is approximately 3.2 and our current ratio is approximately 6.2, as calculated based on the requirements in our covenants. We are in compliance with all terms of our Revolver at June 30, 2016.

5. Derivative Instruments and Hedging Activities

The Company uses derivative instruments to mitigate volatility in commodity prices. While the use of these instruments limits the downside risk of adverse price changes, their use may also limit future revenues from favorable price changes. Depending on changes in oil and gas futures markets and management s view of underlying supply and demand trends, we may increase or decrease our hedging positions.

The following tables summarize our hedging positions as of June 30, 2016 and December 31, 2015:

Hedging Positions

		June 30, 2016			
		Low	High	Weighted Average	Final Expiration
Oil swaps	Exercise price	$ 43.00	$ 92.60	$ 71.60	June 2019
	Offset exercise price	$ 34.70	$ 49.00	$ 45.06	
	Net barrels per month		148,000	65,750	
Natural gas swaps	Exercise price	$ 2.25	$ 5.56	$ 4.03	June 2019
	Offset exercise price	$ 2.34	$ 3.02	$ 2.83	
	Net mmbtu per month		1,470,000	667,222	
Basis swaps	Contract differential	$ (0.30)	$ (0.15)	$ (0.18)	December 2016
	mmbtu per month	1,190,000	1,250,000	1,221,667	
Natural gas liquids swaps	Exercise price	$ 8.90	$ 84.11	$ 26.37	December 2017
	Barrels per month	110,000	133,000	116,333	

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		December 31, 2015			
		Low	High	Weighted Average	Final Expiration
Oil swaps	Exercise price	$ 54.53	$ 100.87	$ 79.16	June 2019
	Barrels per month	54,000	194,000	97,119	
Natural gas swaps	Exercise price	$ 3.22	$ 6.45	$ 4.25	June 2019
	mmbtu per month	700,000	1,640,000	1,042,857	
Basis swaps	Contract differential	$ (0.39)	$ (0.11)	$ (0.18)	December 2016
	mmbtu per month	1,190,000	1,730,000	1,360,833	
Natural gas liquids swaps	Exercise price	$ 8.90	$ 95.24	$ 32.62	December 2017
	Barrels per month	2,000	112,000	51,792	

The Company recognized net losses on derivative instruments of $40.0 million and $22.8 million for the three and six months ended June 30, 2016, respectively. The Company recognized net losses on derivative instruments of $25.1 million and net gains of $21.2 million for the three and six months ended June 30, 2015, respectively,

The Company routinely enters into oil and natural gas swap contracts as seller, thus resulting in a fixed price. In early 2016, the Company crystalized certain mark-to-market gains associated with oil and natural gas hedges the Company had in place for years 2018 and 2019. The gains were effectively crystalized by purchasing, as opposed to selling, oil and natural gas swap contracts for the equal volume that was associated with the initial hedge transaction. Therefore, as prices fluctuate, the loss (or gain) on any single contract in 2018 and 2019 will be offset by an equal gain (or loss). This essentially leaves the underlying production open to fluctuations in market prices. Since no contracts were canceled or liquidated, the gains will be recognized as the hedge contracts mature in 2018 and 2019. Information related to these purchased oil and natural gas swap contracts is presented in the table above as the offset exercise price , and the volumes in the table above are presented net of such purchased oil and natural gas swap contracts.

Offsetting Assets and Liabilities

As of June 30, 2016 the counterparties to our commodity derivative contracts consisted of six financial institutions. All of our counterparties or their affiliates are also lenders under the Revolver. We are not generally required to post additional collateral under our derivative agreements.

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

We adopted the guidance requiring disclosure of both gross and net information about financial instruments eligible for netting in the balance sheet under our derivative agreements. The following table presents information about our commodity derivative contracts that are netted on our Consolidated Balance Sheet as of June 30, 2016 and December 31, 2015:

(in thousands of dollars)	**Net Amount**

	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	
June 30, 2016					
Commodity derivative contracts					
Assets	$ 134,199	$ (10,228)	$ 123,971	$	$ 123,971
Liabilities	(13,565)	10,228	(3,337)		(3,337)
December 31, 2015					
Commodity derivative contracts					
Assets	$ 218,036	$ (527)	$ 217,509	$	$ 217,509
Liabilities	(538)	527	(11)		(11)

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6. Fair Value Measurement

Fair Value of Financial Instruments

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

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

Counterparty credit valuation adjustments are necessary when the market price of an instrument is not indicative of the fair value as a result of the credit quality of the counterparty. Generally, market quotes assume that all counterparties have low default rates and equal credit quality. Therefore, an adjustment may be necessary to reflect the quality of a specific counterparty to determine the fair value of the instrument. The Company currently has all derivative positions placed and held by members of its lending group, which have high 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.

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 June 30, 2016 and December 31, 2015, by consolidated balance sheet caption and by valuation hierarchy, as described above are as follows:

(in thousands of dollars)	June 30, 2016 Fair Value Measurements			
Commodity Price Hedges	**(Level 1)**	**(Level 2)**	**(Level 3)**	**Total**
Current assets (1)	$	$ 63,846	$ (795)	$ 63,051
Long-term assets		60,920		60,920
Current liabilities		764	595	1,359
Long-term liabilities		1,083	895	1,978

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(in thousands of dollars) Commodity Price Hedges	December 31, 2015 Fair Value Measurements (Level 1)	(Level 2)	(Level 3)	Total
Current assets	$	$ 122,779	$ 1,428	$ 124,207
Long-term assets		93,302		93,302
Current liabilities		11		11
Long-term liabilities				

(1) Level 3 current assets are negative as a result of the netting of our commodity derivative reflected on our Consolidated Balance Sheet as of June 30, 2016. Our agreements include set-off provisions as noted in Note 5, Derivative Instruments and Hedging Activities - Offsetting Assets and Liabilities .

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 June 30, 2016:

	Quantitative Information About Level 3 Fair Value Measurements			
Commodity Price Hedges	Fair Value ($ 000 s)	Valuation Technique	Unobservable Input	Range
Natural gas liquid swaps	$ (2,285)	Use a discounted cash flow approach using inputs including forward price statements from counterparties	Natural gas liquid futures prices	$8.90 - $47.25 per barrel

Significant increases/decreases in natural gas liquid prices 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 six months ended June 30, 2016. Changes in fair value of Level 3 instruments represent changes in gains and losses for the periods that are reported in other income (expense). New contracts entered into during the year are generally entered into at no cost with changes in fair value from the date of agreement representing the entire fair value of the instrument. Transfers between levels are evaluated at the end of the reporting period.

(in thousands of dollars)	
Balance at December 31, 2015, net	$ 1,428
Purchases	(2,097)
Settlements	(579)
Transfers to Level 2	
Transfers to Level 3	
Changes in fair value	(1,037)
Balance at June 30, 2016, net	$ (2,285)

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:

	June 30, 2016		December 31, 2015	
(in thousands of dollars)	Principal Amount	Fair Value	Principal Amount	Fair Value
Debt:				
Revolver	$ 185,000	$ 185,000	$ 110,000	$ 110,000
2022 Notes	409,148	330,387	500,000	260,000
2023 Notes	150,000	126,657	250,000	153,283

The Revolver (as defined in Note 4) 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.

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The fair value of the 2022 Notes (as defined in Note 4) is based on pricing that is readily available in the public market. Accordingly, the 2022 Notes are classified as Level 1 in the valuation hierarchy as the pricing is based on quoted market prices for the debt securities and is actively traded.

The fair value of the 2023 Notes (as defined in Note 4) is based on indicative pricing that is available in the public market. Accordingly, the 2023 Notes are classified as Level 2 in the valuation hierarchy as the pricing is based on quoted market prices for the debt securities but is not actively traded.

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. As such, the fair value of oil and gas properties used in estimating impairment represents a nonrecurring Level 3 measurement.

7. Asset Retirement Obligations

A summary of the Company s ARO for the six months ended June 30, 2016 is as follows:

(in thousands of dollars)		
Balance at December 31, 2015	$	20,980
Liabilities incurred		81
Accretion of ARO liability		590
Liabilities settled due to sale of related properties		
Liabilities settled due to plugging and abandonment		(36)
Change in estimate		79
Balance at June 30, 2016		21,694
Less: Current portion of ARO		(679)
Total long-term ARO at June 30, 2016	$	21,015

8. Stock-based Compensation

Management Unit Awards

Effective January 1, 2010, JEH implemented a management incentive plan that provided indirect awards of membership interests in JEH to members of senior management (management units). These awards had various vesting schedules, and a portion of the management units vested in a lump sum at the IPO date. In connection with the IPO, both the vested and unvested management units were converted into the right to receive JEH Units and shares of Class B common stock. The JEH Units (together with a corresponding number of shares of Class B common stock) will become exchangeable under this plan into a like number of shares of Class A common stock upon vesting or forfeiture. No new management units have been awarded since the IPO and no new JEH Units or shares of Class B common stock are created upon a vesting event. Grants listed below reflect the transfer of JEH Units that occurred upon forfeiture.

The following table summarizes information related to the vesting of management units as of June 30, 2016:

	JEH Units	Weighted Average Grant Date Fair Value per Share
Unvested at December 31, 2015	189,355	$ 15.00
Granted	40,630	15.00
Forfeited	(40,630)	15.00
Vested	(96,588)	15.00
Unvested at June 30, 2016	92,767	$ 15.00

Stock compensation expense associated with the management units was $0.2 million and $0.8 million for the three and six months ended June 30, 2016, respectively, and $0.3 million and $0.6 million for the three and six months ended June 30, 2015, respectively, and is included in general and administrative expenses on the Company s Consolidated Statement of Operations.

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2013 Omnibus Incentive Plan

Under the Amended and Restated Jones Energy, Inc. 2013 Omnibus Incentive Plan (the LTIP), established in conjunction with the Company s IPO and amended on May 4, 2016 following approval by the Company s stockholders, the Company has reserved a total of 7,350,000 shares of Class A common stock for non-employee director, consultant, and employee stock-based compensation awards.

The Company granted (i) performance share unit and restricted stock unit awards to certain officers and employees and (ii) restricted shares of Class A common stock to the Company s non-employee directors under the LTIP during 2014, 2015 and 2016. During 2016, the Company also granted performance unit awards to certain members of the senior management team under the LTIP.

Restricted Stock Unit Awards

The Company has outstanding restricted stock unit awards granted to certain officers and employees of the Company under the LTIP. The fair value of the restricted stock unit awards is 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 vesting period, which is typically three years.

The following table summarizes information related to the total number of units awarded to officers and employees as of June 30, 2016:

	Restricted Stock Unit Awards	Weighted Average Grant Date Fair Value per Share
Unvested at December 31, 2015	757,245	$ 11.65
Granted	936,363	3.99
Forfeited	(169,040)	10.85
Vested	(229,388)	11.75
Unvested at June 30, 2016	1,295,180	$ 7.90

Stock compensation expense associated with the employee restricted stock unit awards was $0.9 million and $1.0 million for the three and six months ended June 30, 2016, respectively, and $0.8 million and $1.3 million for the three and six months ended June 30, 2015, respectively, and is included in general and administrative expenses on the Company s Consolidated Statement of Operations.

Performance Share Unit Awards

The Company has outstanding performance share unit awards granted to certain members of the senior management team of the Company under the LTIP. The performance share unit awards were described in earlier filings as performance unit awards. During the second quarter of 2016, the Company created a new class of equity award, described below as a performance unit award, that is settled in cash rather than shares of the Company s Class A common stock. As a result, references to performance unit awards in prior filings refer to this description of performance share unit awards.

Upon the completion of the applicable three-year performance period, each recipient may vest in a number of performance share units. The percent of awarded performance share units in which each recipient vests at such time, if any, 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 share unit is exchangeable for one share of the Company s Class A common stock. The grant date fair value of the performance share units was determined using a Monte Carlo simulation model, which results in an estimated percentage of performance share units earned. The fair value of the performance share units is expensed on a straight-line basis over the applicable three-year performance period.

The following assumptions were used for the Monte Carlo model to determine the grant date fair value and associated stock-based compensation expense of the performance share unit awards granted during the six months ended June 30, 2016:

Forecast period (years)	2.60
Risk-free interest rate	1.00%
Jones stock price volatility	71.47%

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For the performance share units granted during the six months ended June 30, 2016, the Monte Carlo simulation model resulted in approximately 69% of performance share units expected to be earned.

The following table summarizes information related to the total number of performance share units awarded to the senior management team as of June 30, 2016:

	Performance Share Unit Awards	Weighted Average Grant Date Fair Value per Share
Unvested at December 31, 2015	539,188	$ 14.22
Granted	551,252	4.75
Forfeited	(55,235)	13.27
Vested		
Unvested at June 30, 2016	1,035,205	$ 9.23

Stock compensation expense associated with the performance share unit awards was $0.6 million and $1.0 million for the three and six months ended June 30, 2016, respectively, and $0.6 million and $1.1 million for the three and six months ended June 30, 2015, respectively, and is included in general and administrative expenses on the Company s Consolidated Statement of Operations.

Performance Unit Awards

The Company has outstanding performance unit awards, granted initially in 2016, to certain members of the senior management team of the Company under the LTIP. References to performance unit awards in prior filings do not correspond to these newly created performance unit awards. Upon the completion of the applicable three-year performance period, each recipient may vest in a number of performance units. The value of awarded performance units in which each recipient vests at such time, if any, will range from $0 to $200 per performance unit based on the Company s total shareholder return relative to an industry peer group over the applicable three-year performance period. For accounting purposes, the performance units are treated as a liability award with the liability being remeasured at the end of each reporting period. Therefore, the expense associated with these awards is subject to volatility until the payout is finally determined at the end of the performance period. The value of the performance units was determined using a Monte Carlo simulation model, as of the grant date, which results in an estimated final value upon vesting of $1.3 million. The fair value measured as of June 30, 2016 increased to $1.4 million.

The following assumptions were used for the Monte Carlo model to determine the grant date fair value and associated stock-based compensation expense of the performance unit awards granted during the six months ended June 30, 2016:

Forecast period (years)	2.60
Risk-free interest rate	1.00%
Jones stock price volatility	71.47%

For the performance units granted during the six months ended June 30, 2016, the Monte Carlo simulation model resulted in a payout of $67.38 per performance unit was expected to be earned as of the grant date.

Stock compensation expense associated with the performance unit awards was less than $0.1 million for the three and six months ended June 30, 2016, and is included in general and administrative expenses on the Company s Consolidated Statement of Operations. As of June 30, 2016, $1.4 million of unrecognized compensation expense related to the performance unit awards, subject to remeasurement and adjustment for the change in estimated final value as of the end of each reporting period, is expected to be recognized over the remaining weighted-average service period of 2.5 years.

Restricted Stock Awards

The Company has outstanding restricted stock awards granted to the Company s non-employee members of the Board of Directors under the LTIP. The restricted stock will vest upon the director serving as a director of the Company for a one-year service period in accordance with the terms of the award. The fair value of the awards was based on the price of the Company s Class A common stock on the date of grant.

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The following table summarizes information related to the total value of the awards to the Board of Directors as of June 30, 2016:

	Restricted Stock Awards	Weighted Average Grant Date Fair Value per Share
Unvested at December 31, 2015	67,380	$ 7.30
Granted	139,825	4.00
Forfeited		
Vested	(67,380)	7.30
Unvested at June 30, 2016	139,825	4.00

Stock compensation expense associated with the Board of Directors awards was $0.2 million and $0.3 million for the three and six months ended June 30, 2016, respectively, and $0.2 million and $0.3 million for the three and six months ended June 30, 2015, respectively, and is included in general and administrative expenses on the Company s Consolidated Statement of Operations.

9. Income Taxes

The Company records federal and state income tax liabilities associated with its status as a corporation. The Company recognizes 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 was 17.4% and 14.3% for the three and six months ended June 30, 2016, respectively and 20.8% and 19.6% for the three and six months ended June 30, 2015, respectively. The effective rate differs from the statutory rate of 35% due to net income allocated to the non-controlling interest, percentage depletion, state income taxes, and other permanent differences between book and tax accounting.

The Company s income tax provision was a benefit of $12.4 million and $1.7 million for the three and six months ended June 30, 2016, respectively, and a benefit of $13.5 million and $11.1 million for the three and six months ended June 30, 2015, respectively.

The following table summarizes information related to the allocation of the income tax provision between the controlling and non-controlling interests:

	Three months ended June 30,		Six months ended June 30,	
(in thousands of dollars)	2016	2015	2016	2015
Jones Energy, Inc.	$ (12,215)	$ (10,792)	$ (1,646)	$ (10,351)

Non-controlling interest		(173)		(2,661)		(39)		(758)
Income tax provision (benefit)	$	(12,388)	$	(13,453)	$	(1,685)	$	(11,109)

The Company had deferred tax assets for its federal and state net operating loss carry forwards at June 30, 2016 recorded in its 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 June 30, 2016, we have a valuation allowance of $2.7 million as a result of management s assessment of the realizability of deferred tax assets in Oklahoma. Management believes that there will be sufficient future taxable income based on the reversal of temporary differences to enable utilization of substantially all other tax carryforwards.

Tax Receivable Agreement

As of June 30, 2016 and December 31, 2015 the Company had recorded a TRA liability of $38.1 million for the estimated payments that will be made to the pre-IPO members who have exchanged shares. Such exchanges generated tax basis increases leading to deferred tax assets as of June 30, 2016 and December 31, 2015 of $44.8 million, net of valuation allowance. During the three and six months ended June 30, 2016, the amount of the TRA liability was increased by $0.3 million and reduced by $0.2 million, respectively, as a result of the valuation allowance recorded against the Company s deferred tax assets, and is included in other income (expense) on the Company s Consolidated Statement of Operations. The reduction in the TRA liability was offset by an increase of $0.2 million recorded against equity. To the extent the Company does not realize all of the tax benefits in future years or in the event of a change in future tax rates, this liability may change.

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As of June 30, 2016, the Company had not made any payments under the TRA to pre-IPO members who have exchanged JEH Units and Class B common stock for Class A common stock. The Company does not anticipate making a material payment under the TRA in 2016. However, the Company projects to make a payment in 2017 as a result of 2016 taxable income.

Cash Tax Distributions

The holders of JEH Units, including Jones Energy, Inc., incur U.S. federal, state and local income taxes on their share of any taxable income of JEH. Under the terms of its operating agreement, JEH is generally required to make quarterly pro-rata cash tax distributions to its unitholders (including us) based on income allocated to its unitholders through the end of each relevant quarter, as adjusted to take into account good faith projections by the Company of taxable income or loss for the remainder of the calendar year, to the extent JEH has cash available for such distributions and subject to certain other restrictions. This tax distribution is computed based on the estimate of net taxable income of JEH allocated to the holders of JEH Units multiplied by the highest marginal effective rate of federal, state and local income tax applicable to an individual resident in New York, New York, without regard for the federal benefit of the deduction for any state taxes.

A Special Committee of the Board of Directors comprised solely of directors who do not have a direct or indirect interest in such distribution approved, and JEH made, aggregate cash tax distributions of approximately $20.0 million to its unitholders towards its total 2016 projected tax distribution obligation. The distributions were made pro-rata to all members of JEH, and included a $9.9 million payment to the Company, and a $10.1 million payment to Pre-IPO Owners. The 2016 tax distributions are the result of taxable income generated by our operations and debt extinguishment.

10. Stockholders equity

Stockholders equity is comprised of two classes of common stock, Class A common stock and Class B common stock. The Class B common stock is held by the owners of JEH prior to the Company s IPO and can be exchanged (together with a corresponding number of units representing membership interests in 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 holders to one vote on all matters to be voted on by the Company s stockholders generally.

Equity Distribution Agreement

On May 24, 2016, the Company and Jones Energy Holdings, LLC entered into an Equity Distribution Agreement (Equity Distribution Agreement) with Citigroup Global Markets Inc. and Wells Fargo Securities, LLC (each, a Manager and collectively, the Managers). Pursuant to the terms of the Equity Distribution Agreement, the Company may sell from time to time through the Managers, as the Company s sales agents, the Company s Class A common stock having an aggregate offering price of up to $73.0 million (the Class A Shares). Under the terms of the Equity Distribution Agreement, the Company may also sell Class A Shares from time to time to any Manager as principal for its own account at a price to be agreed upon at the time of sale. Any sale of Class A Shares to a Manager as principal would be pursuant to the terms of a separate terms agreement between the Company and such Manager. Sales of the Class A Shares, if any, will be made by means of ordinary brokers transactions, to or through a market maker or directly on or through an electronic communication network, a dark pool or any similar market venue, or as otherwise agreed by the Company and one or more of the Managers.

During the six months ended June 30, 2016, the Company sold approximately 0.3 million Class A Shares under the Equity Distribution Agreement for net proceeds of approximately $1.1 million ($1.3 million gross proceeds, net of approximately $0.2 million in commissions and professional services expenses). The Company used the net proceeds for general corporate purposes. At June 30, 2016, approximately $71.7 million in aggregate offering proceeds remained available to be issued and sold under the Equity Distribution Agreement.

11. 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. Awards of nonvested shares are 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 six months ending June 30, 2016, 1,295,182 restricted stock units, and 1,035,205 performance share units were excluded from the calculation as they would have had an anti-dilutive effect.

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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 six months ended June 30, 2016:

(in thousands, except per share data)	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Income (numerator):				
Net income (loss) attributable to controlling interests	$ (23,245)	$ (18,443)	$ (4,334)	$ (16,255)
Weighted-average shares (denominator):				
Weighted-average number of shares of Class A common stock - basic	30,897	27,904	30,724	23,131
Weighted-average number of shares of Class A common stock - diluted	30,897	27,904	30,724	23,131
Earnings (loss) per share:				
Basic	$ (0.75)	$ (0.66)	$ (0.14)	$ (0.70)
Diluted	$ (0.75)	$ (0.66)	$ (0.14)	$ (0.70)

The sum of the first and second quarter earnings (loss) per share amounts differ from the total earnings (loss) per share for the six months ended June 30, 2016 due to the change in weighted-average shares outstanding.

12. Related Parties

Related Party Transactions

Transactions with Our Executive Officers, Directors and 5% Stockholders

On May 7, 2013, the Company entered into a natural gas sale and purchase agreement with Monarch Natural Gas, LLC, (Monarch), under which Monarch has the first right to gather the natural gas the Company produces from dedicated properties, process the NGLs from this natural gas production and market the processed natural gas and extracted NGLs. Effective May 1, 2015, the rights to gather natural gas under the sale and purchase agreement transferred from Monarch to Enable Midstream Partners LP, (Enable), an unaffiliated third party. Therefore, no related party revenue relating to natural gas and NGL production was recognized during 2016 associated with the aforementioned agreement. The initial term of the agreement, which remains unchanged by the transfer to Enable, runs for 10 years from the effective date of September 1, 2013.

At the time the Company entered into the 2013 Monarch agreement, Metalmark Capital owned approximately 81% 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 our directors, Howard I. Hoffen and Gregory D. Myers, are managing directors of Metalmark Capital.

In connection with the Company s entering into the 2013 Monarch agreement, Monarch issued to JEH equity interests in Monarch, having an estimated fair value of $15 million, in return for marketing services to be provided throughout the term of the agreement. The Company recorded this amount as deferred revenue which is being amortized on an estimated units-of-production basis commencing in September 2013, the first month of product sales to Monarch. The Company amortized $0.6 million and $1.2 million, respectively, of the deferred revenue balance during the three and six months ended June 30, 2016 and $0.5 million and $1.0 million, respectively, during the three and six months ended June 30, 2015. This revenue is included in other revenues on the Company s Consolidated Statement of Operations.

In September 2014, the Company signed a 10 year oil gathering and transportation agreement with Monarch Oil Pipeline LLC, pursuant to which Monarch Oil Pipeline LLC built, at its expense, a new oil gathering system and connected the gathering system to dedicated Company leases in Texas. At the time the Company entered into the agreement, Metalmark Capital owned the majority of the outstanding equity interests of Monarch Oil Pipeline LLC and/or its parent. The system began service during the fourth quarter of 2015 and provides connectivity to both a regional refinery market as well as the Cushing market hub. The Company incurred gathering fees, which were paid to Monarch Oil Pipeline LLC, of $0.7 million and $1.4 million for the three and six months ended June 30, 2016, respectively, associated with the approximately 0.3 MMBoe and 0.7 MMBoe of oil production transported under the agreement. These costs are recorded as an offset to Oil and gas sales in the Company s Consolidated Statement of Operations. The aforementioned production was recognized as Oil and gas sales on the Company s

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Consolidated Statement of Operations at the time it was sold to the purchasers, who are unaffiliated third parties, after passing through the gathering and transportation system.

Purchase of Senior Unsecured Notes

On February 29, 2016, JEH and Jones Energy Finance Corp. purchased $50.0 million principal amount of their outstanding 2023 Notes from investment funds managed by Magnetar Capital and its affiliates, which investment funds collectively own more than 5% of a class of voting securities of the Company, for approximately $23.3 million excluding accrued interest and including any associated fees. On the same day, JEH and Jones Energy Finance Corp. purchased an additional $50.0 million principal amount of their outstanding 2023 Notes from investment funds managed by Blackstone Group Management L.L.C. and its affiliates, which investment funds collectively own more than 5% of a class of voting securities of the Company, for approximately $23.3 million excluding accrued interest and including any associated fees. In conjunction with the extinguishment of this $100.0 million principal amount of debt, JEH recognized cancellation of debt income of $48.3 million on a pre-tax basis. This income is recorded in Gain on debt extinguishment on the Company s Consolidated Statement of Operations.

13. Commitments and Contingencies

The Company is subject to legal proceedings and claims that arise in the ordinary course of its business. When applicable, we record accruals for contingencies when it is probable that a liability will be incurred and the amount of loss can be reasonably estimated. While the outcome of lawsuits and other proceedings against us cannot be predicted with certainty, in the opinion of management, individually or in the aggregate, no such lawsuits are expected to have a material effect on our financial position, results of operations, or liquidity.

In an action filed on June 12, 2015 in the 31st District Court of Hemphill County, Texas, *Donna Kim Flowers and Mitchell Kirk Flowers v. Jones Energy, LLC f/k/a Jones Energy Limited, LLC f/k/a Jones Energy, Ltd.* (Case No. 7225), the Company was sued by Donna Kim Flowers and Mitchell Kirk Flowers (the plaintiffs). The plaintiffs own surface rights to property located in Hemphill County, Texas. The mineral rights are leased to third parties, and the Company is the operator of the Oil and Gas Mineral Lease. On May 28, 2010, the plaintiffs and the Company entered into a Surface Use Agreement concerning Jones fracking operations on the property, which require the Company to minimize disruption and damage to the plaintiffs surface rights. The plaintiffs allege that the Company is in breach of such contract, and seek monetary damages. In June 2016, the Company presented a settlement offer to the plaintiffs. As a result of this settlement offer, the Company has accrued $1.5 million related to its estimated obligation under this settlement offer. This accrual was included in accrued liabilities on the Company s Consolidated Balance Sheet as of June 30, 2016, and the charge was recorded as general and administrative expense on the Company s Consolidated Statement of Operations for the six months ended June 30, 2016. However, no certainty exists that a settlement will be reached or if so, the amount of any such settlement. Therefore, the ultimate loss could be greater or less than the amount accrued. In the event the plaintiffs and the Company are not able to reach a settlement, a court date has been set for October 31, 2016.

14. Subsequent Events

Borrowing Base Redetermination

On August 1, 2016, the Company entered into an amendment to the Revolver to, among other things (i) require that the Company s deposit accounts and securities accounts (subject to certain exclusions) become subject to control agreements, (ii) restrict the Company from making borrowings under the Revolver if the Company has or, after giving effect to the borrowing, will have a Consolidated Cash Balance (as defined in the Revolver) in excess of $30.0 million and (iii) set the borrowing base under the Revolver at $410.0 million effective immediately, with an increase to $425.0 million upon closing of the Pending Anadarko Acquisition.

15. Subsidiary Guarantors

On April 1, 2014, the Issuers sold $500.0 million in aggregate principal amount of the 2022 Notes. On February 23, 2015, the Issuers sold $250.0 million in aggregate principal amount of the 2023 Notes.

The 2022 Notes and the 2023 Notes are guaranteed on a senior unsecured basis by the Company and by all of JEH s current subsidiaries (except Jones Energy Finance Corp. and two immaterial subsidiaries) and certain future subsidiaries, including any future subsidiaries that guarantee any indebtedness under the Revolver. Each subsidiary guarantor is 100% owned by JEH, and all guarantees are full and unconditional, subject to customary exceptions pursuant to the indentures governing our 2022 Notes and 2023 Notes, as discussed below, and joint and several with all other subsidiary guarantees and the parent guarantee. Any subsidiaries of JEH other than the subsidiary guarantors and Jones Energy Finance Corp. are immaterial.

Guarantees of the 2022 Notes and 2023 Notes will be released under certain circumstances, including (i) in connection with any sale or other disposition of (a) all or substantially all of the properties or assets of a guarantor (including by way of merger or consolidation) or (b) all of the capital stock of such guarantor, in each case, to a person that is not the Company or a restricted subsidiary of the Company, (ii) if the Company designates any restricted subsidiary that is a guarantor as an unrestricted subsidiary, (iii) upon legal defeasance, covenant defeasance or satisfaction and discharge of the applicable indenture, or (iv) at such time as such guarantor ceases to guarantee any other indebtedness of the Company or any other guarantor.

The Company is a holding company whose sole material asset is an equity interest in JEH. The Company is the sole managing member of JEH and is responsible for all operational, management and administrative decisions related to JEH s business. In accordance with JEH s limited liability company agreement, the Company may not be removed as the sole managing member of JEH.

As of June 30, 2016, the Company held approximately 50.0% of the economic interest in JEH, with the remaining 50.0% economic interest held by a group of investors that owned interests in JEH prior to the Company s IPO (the Pre-IPO Owners). The Pre-IPO Owners have no voting rights with respect to their economic interest in JEH.

The Company has two classes of common stock, Class A common stock, which was sold to investors in the IPO, and Class B common stock. Pursuant to the Company s certificate of incorporation, each share of Class A common stock is entitled to one vote per share, and the shares of Class A common stock are entitled to 100% of the economic interests in the Company. Each share of Class B common stock has no economic rights in the Company, but entitles its holder to one vote on all matters to be voted on by the Company s stockholders generally.

In connection with a reorganization that occurred immediately prior to the IPO, each Existing Owner was issued a number of shares of Class B common stock that was equal to the number of JEH Units that such Existing Owner held. Holders of the Company s Class A common stock and Class B common stock generally vote together as a single class on all matters presented to the Company s stockholders for their vote or approval. Accordingly, the Pre-IPO Owners collectively have a number of votes in the Company equal to the aggregate number of JEH Units that they hold.

The Pre-IPO Owners have the right, pursuant to the terms of an Exchange Agreement by and among the Company, JEH and each of the Pre-IPO Owners, to exchange their JEH Units (together with a corresponding number of shares of Class B common stock) 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. As a result, the Company expects that over time the Company will have an increasing economic interest in JEH as Class B common stock and JEH Units are exchanged for Class A common stock. Moreover, any transfers of JEH Units outside of the Exchange Agreement (other than permitted transfers to affiliates) must be approved by the Company. The Company intends to retain full voting and management control over JEH.

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Jones Energy, Inc.

Condensed Consolidating Balance Sheet

June 30, 2016

(in thousands of dollars)	JEI (Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets						
Current assets						
Cash	$ 10,010	$ 11,674	$ 37,594	$ 20	$	$ 59,298
Accounts receivable, net						
Oil and gas sales			18,397			18,397
Joint interest owners			4,701			4,701
Other		10,903	190			11,093
Commodity derivative assets		63,051				63,051
Other current assets		401	2,247			2,648
Intercompany receivable	16,802	1,183,655			(1,200,457)	
Total current assets	26,812	1,269,684	63,129	20	(1,200,457)	159,188
Oil and gas properties, net, at cost under the successful efforts method			1,580,248			1,580,248
Other property, plant and equipment, net			2,617	664		3,281
Commodity derivative assets		60,920				60,920
Other assets		6,656	709			7,365
Investment in subsidiaries	429,419				(429,419)	
Total assets	$ 456,231	$ 1,337,260	$ 1,646,703	$ 684	$ (1,629,876)	$ 1,811,002
Liabilities and Stockholders Equity						
Current liabilities						
Trade accounts payable	$ 91	$ 206	$ 18,643	$	$	$ 18,940
Oil and gas sales payable			25,224			25,224
Accrued liabilities	1,534	11,807	10,115			23,456
Commodity derivative liabilities		1,359				1,359
Asset retirement obligations			679			679
Intercompany payable			1,408,566	2,487	(1,411,053)	
Total current liabilities	1,625	13,372	1,463,227	2,487	(1,411,053)	69,658
Long-term debt		729,856				729,856
Deferred revenue		10,176				10,176
Commodity derivative liabilities		1,978				1,978
Asset retirement obligations			21,015			21,015
Liability under tax receivable agreement	38,064					38,064
Deferred tax liabilities	16,296	3,541				19,837
Total liabilities	55,985	758,923	1,484,242	2,487	(1,411,053)	890,584
Stockholders / members equity						
Members equity		578,337	162,461	(1,803)	(738,995)	
Class A common stock, $0.001 par value; 31,266,437 shares issued and 31,243,835 shares	32					32

outstanding						
Class B common stock, $0.001 par value; 31,230,213 shares issued and outstanding	31					31
Treasury stock, at cost; 22,602 shares	(358)					(358)
Additional paid-in-capital	368,306					368,306
Retained earnings	32,235					32,235
Stockholders equity	400,246	578,337	162,461	(1,803)	(738,995)	400,246
Non-controlling interest					520,172	520,172
Total stockholders equity	400,246	578,337	162,461	(1,803)	(218,823)	920,418
Total liabilities and stockholders equity	$ 456,231	$ 1,337,260	$ 1,646,703	$ 684	$ (1,629,876)	$ 1,811,002

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Jones Energy, Inc.

Condensed Consolidating Balance Sheet

December 31, 2015

(in thousands of dollars)	JEI(Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets						
Current assets						
Cash	$ 100	$ 12,448	$ 9,325	$ 20	$	$ 21,893
Accounts receivable, net						
Oil and gas sales			19,292			19,292
Joint interest owners			11,314			11,314
Other		14,444	726			15,170
Commodity derivative assets		124,207				124,207
Other current assets		444	1,854			2,298
Intercompany receivable	12,866	1,161,997			(1,174,863)	
Total current assets	12,966	1,313,540	42,511	20	(1,174,863)	194,174
Oil and gas properties, net, at cost under the successful efforts method			1,635,766			1,635,766
Other property, plant and equipment, net			3,168	705		3,873
Commodity derivative assets		93,302				93,302
Other assets		7,456	583			8,039
Investment in subsidiaries	444,362				(444,362)	
Total assets	$ 457,328	$ 1,414,298	$ 1,682,028	$ 725	$ (1,619,225)	$ 1,935,154
Liabilities and Stockholders Equity						
Current liabilities						
Trade accounts payable	$	$ 388	$ 7,079	$	$	$ 7,467
Oil and gas sales payable			32,408			32,408
Accrued liabilities		15,741	11,600			27,341
Commodity derivative liabilities		11				11
Asset retirement obligations			679			679
Intercompany payable			1,391,838	2,434	(1,394,272)	
Total current liabilities		16,140	1,443,604	2,434	(1,394,272)	67,906
Long-term debt		837,654				837,654
Deferred revenue		11,417				11,417
Asset retirement obligations			20,301			20,301
Liability under tax receivable agreement	38,052					38,052
Deferred tax liabilities	19,280	3,692				22,972
Total liabilities	57,332	868,903	1,463,905	2,434	(1,394,272)	998,302
Stockholders / members equity						
Members equity		545,395	218,123	(1,709)	(761,809)	
Class A common stock, $0.001 par value; 30,573,509 shares issued and 30,550,907 shares outstanding	31					31

Class B common stock, $0.001 par value; 31,273,130 shares issued and outstanding	31					31
Treasury stock, at cost: 22,602 shares	(358)					(358)
Additional paid-in-capital	363,723					363,723
Retained earnings	36,569					36,569
Stockholders equity	399,996	545,395	218,123	(1,709)	(761,809)	399,996
Non-controlling interest					536,856	536,856
Total stockholders equity	399,996	545,395	218,123	(1,709)	(224,953)	936,852
Total liabilities and stockholders equity	$ 457,328	$ 1,414,298	$ 1,682,028	$ 725	$ (1,619,225)	$ 1,935,154

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Jones Energy, Inc.

Condensed Consolidating Statement of Operations

Three Months Ended June 30, 2016

(in thousands)	JEI (Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Operating revenues						
Oil and gas sales	$	$	$ 28,398	$	$	$ 28,398
Other revenues		596	150			746
Total operating revenues		596	28,548			29,144
Operating costs and expenses						
Lease operating			7,545			7,545
Production and ad valorem taxes			1,727			1,727
Exploration			77			77
Depletion, depreciation and amortization			38,118	19		38,137
Accretion of ARO liability			297			297
General and administrative		3,293	4,806	27		8,126
Total operating expenses		3,293	52,570	46		55,909
Operating income (loss)		(2,697)	(24,022)	(46)		(26,765)
Other income (expense)						
Interest expense		(12,727)	(80)			(12,807)
Gain on debt extinguishment		8,878				8,878
Net gain (loss) on commodity derivatives		(40,002)				(40,002)
Other income (expense)	(267)	(73)	2			(338)
Other income (expense), net	(267)	(43,924)	(78)			(44,269)
Income (loss) before income tax	(267)	(46,621)	(24,100)	(46)		(71,034)
Equity interest in income	(35,100)				35,100	
Income tax provision (benefit)	(12,122)	(266)				(12,388)
Net income (loss)	$ (23,245)	$ (46,355)	$ (24,100)	$ (46)	$ 35,100	$ (58,646)
Net income (loss) attributable to non-controlling interests					(35,401)	(35,401)
Net income (loss) attributable to controlling interests	$ (23,245)	$	$	$	$	$ (23,245)

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Jones Energy, Inc.

Condensed Consolidating Statement of Operations

Six Months Ended June 30, 2016

(in thousands)	**JEI (Parent)**	**Issuers**	**Guarantor Subsidiaries**	**Non-Guarantor Subsidiaries**	**Eliminations**	**Consolidated**
Operating revenues						
Oil and gas sales	$	$	$ 53,478	$	$	$ 53,478
Other revenues		1,241	283			1,524
Total operating revenues		1,241	53,761			55,002
Operating costs and expenses						
Lease operating			16,162			16,162
Production and ad valorem taxes			3,328			3,328
Exploration			239			239
Depletion, depreciation and amortization			79,857	42		79,899
Accretion of ARO liability			590			590
General and administrative		6,171	9,407	52		15,630
Total operating expenses		6,171	109,583	94		115,848
Operating income (loss)		(4,930)	(55,822)	(94)		(60,846)
Other income (expense)						
Interest expense		(27,766)	161			(27,605)
Gain on debt extinguishment		99,530				99,530
Net gain (loss) on commodity derivatives		(22,783)				(22,783)
Other income (expense)	162	(274)	(1)			(113)
Other income (expense), net	162	48,707	160			49,029
Income (loss) before income tax	162	43,777	(55,662)	(94)		(11,817)
Equity interest in income	(6,132)				6,132	
Income tax provision (benefit)	(1,636)	(49)				(1,685)
Net income (loss)	$ (4,334)	$ 43,826	$ (55,662)	$ (94)	$ 6,132	$ (10,132)
Net income (loss) attributable to non-controlling interests					(5,798)	(5,798)
Net income (loss) attributable to controlling interests	$ (4,334)	$	$	$	$	$ (4,334)

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Jones Energy, Inc.

Condensed Consolidating Statement of Operations

Three Months Ended June 30, 2015

(in thousands)	JEI (Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Operating revenues						
Oil and gas sales	$	$	$ 53,222	$	$	$ 53,222
Other revenues		503	192			695
Total operating revenues		503	53,414			53,917
Operating costs and expenses						
Lease operating			11,796			11,796
Production and ad valorem taxes			3,071			3,071
Exploration			464			464
Depletion, depreciation and amortization			51,280	22		51,302
Accretion of ARO liability			206			206
General and administrative		158	9,251	24		9,433
Other operating			1,176			1,176
Total operating expenses		158	77,244	46		77,448
Operating income (loss)		345	(23,830)	(46)		(23,531)
Other income (expense)						
Interest expense		(16,464)	(238)			(16,702)
Net gain (loss) on commodity derivatives		(25,075)				(25,075)
Other income (expense)		(28)	703			675
Other income (expense), net		(41,567)	465			(41,102)
Income (loss) before income tax		(41,222)	(23,365)	(46)		(64,633)
Equity interest in income	(28,725)				28,725	
Income tax provision (benefit)	(10,282)	(3,171)				(13,453)
Net income (loss)	$ (18,443)	$ (38,051)	$ (23,365)	$ (46)	$ 28,725	$ (51,180)
Net income (loss) attributable to non-controlling interests					(32,737)	(32,737)
Net income (loss) attributable to controlling interests	$ (18,443)	$	$	$	$	$ (18,443)

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Jones Energy, Inc.

Condensed Consolidating Statement of Operations

Six Months Ended June 30, 2015

(in thousands)	JEI (Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Operating revenues						
Oil and gas sales	$	$	$ 110,456	$	$	$ 110,456
Other revenues		1,028	529			1,557
Total operating revenues		1,028	110,985			112,013
Operating costs and expenses						
Lease operating			24,058			24,058
Production and ad valorem taxes			6,779			6,779
Exploration			628			628
Depletion, depreciation and amortization			103,340	45		103,385
Accretion of ARO liability			400			400
General and administrative		2,985	14,912	47		17,944
Other operating			4,188			4,188
Total operating expenses		2,985	154,305	92		157,382
Operating income (loss)		(1,957)	(43,320)	(92)		(45,369)
Other income (expense)						
Interest expense		(30,148)	(683)			(30,831)
Net gain (loss) on commodity derivatives		21,231				21,231
Other income (expense)		(2,301)	677			(1,624)
Other income (expense), net		(11,218)	(6)			(11,224)
Income (loss) before income tax		(13,175)	(43,326)	(92)		(56,593)
Equity interest in income	(26,096)				26,096	
Income tax provision (benefit)	(9,841)	(1,268)				(11,109)
Net income (loss)	$ (16,255)	$ (11,907)	$ (43,326)	$ (92)	$ 26,096	$ (45,484)
Net income (loss) attributable to non-controlling interests					(29,229)	(29,229)
Net income (loss) attributable to controlling interests	$ (16,255)	$	$	$	$	$ (16,255)

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Jones Energy, Inc.

Condensed Consolidating Statement of Cash Flows

Six Months Ended June 30, 2016

(in thousands of dollars)	JEI (Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows from operating activities						
Net income (loss)	$ (4,334)	$ 43,826	$ (55,662)	$ (94)	$ 6,132	$ (10,132)
Adjustments to reconcile net income (loss) to net cash provided by operating activities	3,278	(92,614)	111,506	94	(6,132)	16,132
Net cash provided by / (used in) operations	(1,056)	(48,788)	55,844			6,000
Cash flows from investing activities						
Additions to oil and gas properties			(27,592)			(27,592)
Proceeds from sales of assets			5			5
Acquisition of other property, plant and equipment (net of reimbursements)			12			12
Current period settlements of matured derivative contracts		77,622				77,622
Net cash (used in) / provided by investing		77,622	(27,575)			50,047
Cash flows from financing activities						
Proceeds from issuance of long-term debt		75,000				75,000
Purchase of senior notes		(84,589)				(84,589)
Net distributions paid to JEH unitholders	9,910	(20,019)				(10,109)
Proceeds from sale of common stock, net of expense	1,056					1,056
Net cash provided by / (used in) financing	10,966	(29,608)				(18,642)
Net increase (decrease) in cash	9,910	(774)	28,269			37,405
Cash						
Beginning of period	100	12,448	9,325	20		21,893
End of period	$ 10,010	$ 11,674	$ 37,594	$ 20	$	$ 59,298

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Jones Energy, Inc.

Condensed Consolidating Statement of Cash Flows

Six Months Ended June 30, 2015

(in thousands of dollars)	JEI (Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows from operating activities						
Net income (loss)	$ (16,255)	$ (11,907)	$ (43,326)	$ (92)	$ 26,096	$ (45,484)
Adjustments to reconcile net income (loss) to net cash provided by operating activities	(106,524)	(21,934)	273,289	92	(26,096)	118,827
Net cash provided by / (used in) operations	(122,779)	(33,841)	229,963			73,343
Cash flows from investing activities						
Additions to oil and gas properties			(229,060)			(229,060)
Proceeds from sales of assets			21			21
Acquisition of other property, plant and equipment			(382)			(382)
Current period settlements of matured derivative contracts		67,646				67,646
Net cash (used in) / provided by investing		67,646	(229,421)			(161,775)
Cash flows from financing activities						
Proceeds from issuance of long-term debt		75,000				75,000
Repayment under long-term debt		(335,000)				(335,000)
Proceeds from senior notes		236,475				236,475
Payment of debt issuance costs		(1,513)				(1,513)
Proceeds from sale of common stock, net of expense	122,779					122,779
Net cash provided by / (used in) financing	122,779	(25,038)				97,741
Net increase (decrease) in cash		8,767	542			9,309
Cash						
Beginning of period	100	1,000	12,436	30		13,566
End of period	$ 100	$ 9,767	$ 12,978	$ 30	$	$ 22,875

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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, 2015, filed on March 9, 2016 with the Securities and Exchange Commission, and with the unaudited consolidated financial statements and related notes thereto presented in this Quarterly Report and in our quarterly report for the quarter ended March 31, 2016, filed on May 6, 2016 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). Jones Energy, Inc. (JONE) is a holding company whose sole material asset is an equity interest in JEH.

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 mid-continent United States, spanning areas 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. We have drilled 836 total wells as operator, including 660 horizontal wells, since our formation and delivered compelling rates of return over various commodity price cycles. Our operations are focused on horizontal drilling and completions within two distinct basins in the Texas Panhandle and Oklahoma:

- the Anadarko Basin targeting the liquids rich Cleveland, Granite Wash, Tonkawa and Marmaton formations; and

- the Arkoma Basin targeting the Woodford shale formation.

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

Second Quarter and Year-to-Date 2016 Highlights:

- Average daily net production for the second quarter 2016 of 18.6 MBoe/d, with oil production of 4.4 MBbl/d

- Lease operating expense for the second quarter 2016 of $7.5 million, down 12% from last quarter

- Entered into an agreement to acquire approximately 26,000 net acres in Anadarko Basin for $27.1 million, which is expected to add 92 gross/68 net Cleveland locations in core footprint, or approximately 1.5 years of drilling inventory at current rig pace

- Net loss for the second quarter of 2016 of $58.6 million and EBITDAX of $46.2 million

Pending Anadarko Acquisition

On August 3, 2016, the Company announced it has entered into a definitive agreement to acquire producing and undeveloped oil and gas assets in the Anadarko Basin (the Pending Anadarko Acquisition) for $27.1 million, subject to customary closing adjustments. The assets subject to the Pending Anadarko Acquisition include approximately 26,000 net acres in Lipscomb and Ochiltree Counties in the Texas Panhandle. The Company expects to fund the Pending Anadarko Acquisition with cash on hand, and anticipates the transaction will close by the end of August, subject to completion of due diligence and satisfaction of customary closing conditions.

Pending Anadarko Acquisition Highlights:

- Approximately 26,000 net acres in the Anadarko Basin

- Expected to add 92 gross/68 net locations in core Cleveland footprint

- Acreage is 98% held by production with no near-term lease expirations

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- Daily net production expected to be approximately 850 Boe/d as of August 2016

Updated Capital Expenditures Outlook

In our Annual Report on Form 10-K for the year ended December 31, 2015, we provided an overview of our 2016 capital expenditures budget, which was initially set at $25 million with the majority dedicated to capital well workovers and field optimization activities. On May 4, 2016 the Company announced a revised 2016 capital expenditures program of $100 million. The Company resumed drilling with one rig in the Cleveland in April 2016, followed by the addition of a second and third rig in June 2016. On August 3, 2016, the Company announced a further revised 2016 capital expenditures program, lowering full year 2016 guidance (excluding acquisitions) by 10% to $90 million, primarily due to better than expected execution on the Company s Cleveland drilling program and maintenance projects coming in below budget. The Company expects to fund its revised capital budget with cash flows from operations.

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Results of Operations

The following table sets forth selected financial data of Jones Energy, Inc. for the periods indicated.

(in thousands of dollars except for production, sales price and average cost data)	Three Months Ended June 30, 2016	2015	Change	Six Months Ended June 30, 2016	2015	Change
Revenues:						
Oil	$ 16,108	$ 33,316	$ (17,208)	$ 29,422	$ 66,665	$ (37,243)
Natural gas	5,115	10,596	(5,481)	11,657	25,103	(13,446)
NGLs	7,175	9,310	(2,135)	12,399	18,688	(6,289)
Total oil and gas	28,398	53,222	(24,824)	53,478	110,456	(56,978)
Other	746	695	51	1,524	1,557	(33)
Total operating revenues	29,144	53,917	(24,773)	55,002	112,013	(57,011)
Costs and expenses:						
Lease operating	7,545	11,796	(4,251)	16,162	24,058	(7,896)
Production and ad valorem taxes	1,727	3,071	(1,344)	3,328	6,779	(3,451)
Exploration	77	464	(387)	239	628	(389)
Depletion, depreciation and amortization	38,137	51,302	(13,165)	79,899	103,385	(23,486)
Accretion of ARO liability	297	206	91	590	400	190
General and administrative	8,126	9,433	(1,307)	15,630	17,944	(2,314)
Other operating		1,176	(1,176)		4,188	(4,188)
Total costs and expenses	55,909	77,448	(21,539)	115,848	157,382	(41,534)
Operating income (loss)	(26,765)	(23,531)	(3,234)	(60,846)	(45,369)	(15,477)
Other income (expenses):						
Interest expense	(12,807)	(16,702)	3,895	(27,605)	(30,831)	3,226
Gain on debt extinguishment	8,878		8,878	99,530		99,530
Net gain (loss) on commodity derivatives	(40,002)	(25,075)	(14,927)	(22,783)	21,231	(44,014)
Other income (expense)	(338)	675	(1,013)	(113)	(1,624)	1,511
Total other income (expense)	(44,269)	(41,102)	(3,167)	49,029	(11,224)	60,253
Income (loss) before income tax	(71,034)	(64,633)	(6,401)	(11,817)	(56,593)	44,776
Income tax provision	(12,388)	(13,453)	1,065	(1,685)	(11,109)	9,424
Net income (loss)	(58,646)	(51,180)	(7,466)	(10,132)	(45,484)	35,352
Net income (loss) attributable to non-controlling interests	(35,401)	(32,737)	(2,664)	(5,798)	(29,229)	23,431
Net income (loss) attributable to controlling interests	$ (23,245)	$ (18,443)	$ (4,802)	$ (4,334)	$ (16,255)	$ 11,921
Net production volumes:						
Oil (MBbls)	396	644	(248)	875	1,400	(525)
Natural gas (MMcf)	4,608	6,139	(1,531)	9,528	12,103	(2,575)
NGLs (MBbls)	529	637	(108)	1,084	1,264	(180)
Total (MBoe)	1,693	2,304	(611)	3,547	4,681	(1,134)
Average net (Boe/d)	18,604	25,319	(6,715)	19,489	25,862	(6,373)
Average sales price, unhedged:						
Oil (per Bbl), unhedged	$ 40.68	$ 51.73	$ (11.05)	$ 33.63	$ 47.62	$ (13.99)
Natural gas (per Mcf), unhedged	1.11	1.73	(0.62)	1.22	2.07	(0.85)
NGLs (per Bbl), unhedged	13.56	14.62	(1.06)	11.44	14.78	(3.34)
Combined (per Boe) realized, unhedged	16.77	23.10	(6.33)	15.08	23.60	(8.52)
Average sales price, hedged:						
Oil (per Bbl), hedged	$ 87.87	$ 75.59	$ 12.28	$ 85.77	$ 73.64	$ 12.13
Natural gas (per Mcf), hedged	3.40	3.20	0.20	3.54	3.44	0.10
NGLs (per Bbl), hedged	17.64	27.09	(9.45)	17.33	27.25	(9.92)
Combined (per Boe) realized, hedged	35.33	37.14	(1.81)	35.96	38.28	(2.32)
Average costs (per Boe):						
Lease operating	$ 4.46	$ 5.12	$ (0.66)	$ 4.56	$ 5.14	$ (0.58)
Production and ad valorem taxes	1.02	1.33	(0.31)	0.94	1.45	(0.51)
Depletion, depreciation and amortization	22.53	22.27	0.26	22.53	22.09	0.44
General and administrative	4.80	4.09	0.71	4.41	3.83	0.58

Non-GAAP financial measures

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. 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

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presentation of EBITDAX should not be construed as an inference that our results will be unaffected by unusual or nonrecurring 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:

(in thousands of dollars)	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Reconciliation of EBITDAX to net income				
Net income (loss)	$ (58,646)	$ (51,180)	$ (10,132)	$ (45,484)
Interest expense	12,083	15,902	26,118	29,263
Exploration expense	77	464	239	628
Income taxes	(12,388)	(13,453)	(1,685)	(11,109)
Amortization of deferred financing costs	724	800	1,487	1,568
Depreciation and depletion	38,137	51,302	79,899	103,385
Accretion of ARO liability	297	206	590	400
Reduction of TRA liability	267		(162)	
Other non-cash charges	1,645	353	1,111	760
Stock compensation expense	1,899	1,824	3,084	3,248
Deferred and other non-cash compensation expense	133	109	401	218
Net (gain) loss on commodity derivatives	40,002	25,075	22,783	(21,231)
Current period settlements of matured derivative contracts	31,410	32,344	74,081	68,719
Amortization of deferred revenue	(596)	(503)	(1,241)	(1,028)
(Gain) loss on sales of assets	(3)	(20)	1	6
(Gain) on debt extinguishment	(8,878)		(99,530)	
Stand-by rig costs		1,176		4,188
Financing expenses and other debt fees	73	28	273	2,301
EBITDAX	$ 46,236	$ 64,427	$ 97,317	$ 135,832

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 other items described below. We define Adjusted Earnings per Share as earnings per share plus that portion of the components of adjusted net income allocated to the controlling interests divided by weighted average shares outstanding. We believe adjusted net income and adjusted earnings per share are useful to investors because they provide readers with a more meaningful measure of our profitability before recording certain items for which the timing or amount cannot be reasonably determined. However, these measures are 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 periods indicated:

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(in thousands of dollars, except per share data)	Three Months Ended June 30, 2016	Three Months Ended June 30, 2015	Six Months Ended June 30, 2016	Six Months Ended June 30, 2015
Net income (loss)	$ (58,646)	$ (51,180)	$ (10,132)	$ (45,484)
Net (gain) loss on commodity derivatives	40,002	25,075	22,783	(21,231)
Current period settlements of matured derivative contracts	31,410	32,344	74,081	68,719
Exploration	77	464	239	628
Non-cash stock compensation expense	1,899	1,824	3,084	3,248
Deferred and other non-cash compensation expense	133	109	401	218
(Gain) on debt extinguishment	(8,878)		(99,530)	
Stand-by rig costs		1,176		4,188
Financing expenses				2,250
Reduction of TRA liability	267		(162)	
Tax impact of adjusting items (1)	(11,390)	(9,593)	(331)	(9,272)
Change in valuation allowance	(597)		392	
Adjusted net income (loss)	$ (5,723)	$ 219	$ (9,175)	$ 3,264
Adjusted net income (loss) attributable to non-controlling interests	(2,948)	899	(5,566)	2,394
Adjusted net income (loss) attributable to controlling interests	$ (2,775)	$ (680)	$ (3,609)	$ 870
Earnings (loss) per share (basic and diluted)	$ (0.75)	$ (0.66)	$ (0.14)	$ (0.70)
Net (gain) loss on commodity derivatives	0.64	0.41	0.37	(0.16)
Current period settlements of matured derivative contracts	0.51	0.52	1.20	1.15
Exploration		0.01		0.01
Non-cash stock compensation expense	0.03	0.03	0.05	0.06
Deferred and other non-cash compensation expense			0.01	
(Gain) on debt extinguishment	(0.14)		(1.60)	
Stand-by rig costs		0.02		0.05
Financing expenses				0.04
Reduction of TRA liability	0.01		(0.01)	
Tax impact of adjusting items (1)	(0.37)	(0.35)	(0.01)	(0.41)
Change in valuation allowance	(0.02)		0.01	
Adjusted earnings (loss) per share (basic and diluted)	$ (0.09)	$ (0.02)	$ (0.12)	$ 0.04
Weighted average shares outstanding:				
Basic and diluted	30,897	27,904	30,724	23,131
Effective tax rate on net income (loss) attributable to controlling interests	36.8%	37.0%	36.8%	37.0%

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

Results of Operations - Three months ended June 30, 2016 as compared to three months ended June 30, 2015

Operating revenues

Oil and gas sales. Oil and gas sales decreased $24.8 million, or 46.6%, to $28.4 million for the three months ended June 30, 2016, as compared to $53.2 million for the three months ended June 30, 2015. The decrease was attributable to the decline in commodity prices ($11.6 million), as well as decreased production volumes ($13.2 million). The decrease in production volumes was driven by the temporary suspension of our drilling program. The average realized oil price, excluding the effects of commodity derivative instruments, decreased from $51.73 per Bbl for the three months ended June 30, 2015 to $40.68 per Bbl for the three months ended June 30, 2016, or 21.4%. The average realized natural gas price, excluding the effects of commodity derivative instruments, decreased from $1.73 per Mcf for the three months ended June 30, 2015 to $1.11 per Mcf for the three months ended June 30, 2016, or 35.8%. The average realized natural gas liquids price, excluding the effects of commodity derivative instruments, decreased from $14.62 per Bbl for the three months ended June 30, 2015 to $13.56 per Bbl for the three months ended June 30, 2016, or 7.3%. Average daily production decreased 26.5% to 18,604 Boe per day for the three months ended June 30, 2016 as compared to 25,319 Boe per day for the three months ended June 30, 2015.

Costs and expenses

Lease operating. Lease operating expenses decreased by $4.3 million, or 36.4%, to $7.5 million for the three months ended June 30, 2016, as compared to $11.8 million for the three months ended June 30, 2015. The decrease was principally attributable to reduction in post-completion costs driven by a temporary suspension of the drilling program, operational focus on reducing recurring operating expenses, such as optimizing the usage of compressors and rental equipment, and vendor price reductions. On a per unit basis, lease operating expenses decreased $0.66 per Boe, or 12.9%, from $5.12 per Boe in the three months ended June 30, 2015 to $4.46 per Boe in the three months ended June 30, 2016.

Production and ad valorem taxes. Production and ad valorem taxes decreased by $1.4 million, or 45.2%, to $1.7 million for the three months ended June 30, 2016, as compared to $3.1 million for the three months ended June 30, 2015. The decrease was driven by a $0.7 million (70.0%) reduction in production taxes, which decreased in conjunction with the 46.6% decrease in oil and gas revenue. Production tax rates vary between states, products, and production levels; therefore, the overall blended rate is impacted by numerous factors and the mix of producing wells at any given time. Additionally, estimated ad valorem taxes decreased $0.7 million from $1.0 million for the three months ended June 30, 2015 to $0.3 million for the three months ended June 30, 2016, reflecting lower property assessments due to lower commodity prices. The average effective rate excluding the impact of ad valorem taxes increased from 3.8% for the three months ended June 30, 2015 to 4.8% for the three months ended June 30, 2016.

Exploration. Exploration expense decreased from $0.5 million for the three months ended June 30, 2015 to $0.1 million for the three months ended June 30, 2016. Spending during the second quarter of 2016 primarily related to geological data and seismic processing associated with unproved acreage. No exploratory wells were drilled during either year.

Depreciation, depletion and amortization. Depreciation, depletion and amortization decreased by $13.2 million, or 25.7%, to $38.1 million for the three months ended June 30, 2016, as compared to $51.3 million for the three months ended June 30, 2015. The decrease was primarily the result of lower production caused by a reduction in capital spending driven by a temporary suspension of the drilling program. On a per unit basis, depletion expense increased $0.26 per Boe or 1.2% from $22.27 per Boe for the three months ended June 30, 2015 as compared to $22.53 per Boe for the three months ended June 30, 2016.

General and administrative. General and administrative expenses decreased by $1.3 million, or 13.8%, to $8.1 million for the three months ended June 30, 2016, as compared to $9.4 million for the three months ended June 30, 2015. The decrease in general and administrative expense was primarily attributable to staff and other cost reductions. Non-cash compensation expense increased $0.1 million from $1.9 million for the three months ended June 30, 2015 to $2.0 million for the three months ended June 30, 2016. On a per unit basis, general and administrative expenses, excluding non-cash items, decreased from $3.10 per Boe for the three months ended June 30, 2015 to $2.63 per Boe for the three months ended June 30, 2016.

Other operating expense. Other operating expense decreased from $1.2 million for the three months ended June 30, 2015 to none for the three months ended June 30, 2016. Expense for the three months ended June 30, 2015 represents stand-by rig costs associated with the early termination of drilling rig contracts. There were no similar charges during 2016.

Interest expense. Interest expense decreased by $3.9 million, or 23.4%, to $12.8 million for three months ended June 30, 2016, as compared to $16.7 million for the three months ended June 30, 2015. The decrease was driven by a reduction in the outstanding balance of the 2022 Notes and the 2023 Notes as a result of our debt extinguishments. During the three months ended June 30, 2016, borrowings under the Revolver, the 2022 Notes and the 2023 Notes bore interest at a weighted average rate of 2.25%, 6.75% and 9.25%, respectively. Average outstanding balances for the three months ended June 30, 2016 were $185.0 million, $411.1 million and $150.0 million under the Revolver, the 2022 Notes and the 2023 Notes, respectively.

Gain on debt extinguishment. The gain on debt extinguishment of $8.9 million for the three months ended June 30, 2016 was related to the purchase of an aggregate principal amount of $20.3 million of our senior unsecured notes for cash of $11.2 million. The company recognized accelerated amortization of debt issuance costs of $0.3 million associated with the cancellation. See Note 4, Long-Term Debt, for further details regarding the debt extinguishment. There were no similar gains during 2015.

Net gain (loss) on commodity derivatives. The net gain (loss) on commodity derivatives was a net loss of $40.0 million for the three months ended June 30, 2016, as compared to a net loss of $25.1 million for the three months ended June 30, 2015. The loss was driven by higher average crude oil and natural gas prices ($45.46 per barrel and $2.15 per Mcf, respectively) for the three months ended June 30, 2016, as compared to the crude oil and natural gas prices as of March 31, 2016 ($33.35 per barrel and $1.99 per Mcf, respectively) as well as additional hedging activity during 2016.

Other income (expense). Other income (expense) decreased by $1.0 million to net expense of $0.3 million for the three months ended June 30, 2016, as compared to a net income of $0.7 million for the three months ended June 30, 2015. Other income (expense) for the three months ended June 30, 2016 related to a reduction of the TRA valuation allowance which resulted in expense of $0.3 million. Other income (expense) for the three months ended June 30, 2015 was income of $0.7 million related to the receipt of dividend income from our investment in Monarch Natural Gas Holdings, LLC.

Income taxes. The provision for federal and state income taxes for the three months ended June 30, 2016 was a benefit of $12.4 million resulting in an 17.4% effective tax rate as a percentage of our pre-tax book income for the quarter as compared to a benefit of

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$13.5 million for the three months ended June 30, 2015. Our effective tax rate is based on the statutory rate applicable to the U.S. and the blended rate of the states in which we conduct business and is adjusted from the enacted rates for the share of net income allocated to the non-controlling interest. See Note 9, Income Taxes, for further details.

Results of Operations - Six months ended June 30, 2016 as compared to six months ended June 30, 2015

Operating revenues

Oil and gas sales. Oil and gas sales decreased $57.0 million, or 51.6%, to $53.5 million for the six months ended June 30, 2016, as compared to $110.5 million for the six months ended June 30, 2015. The decrease was attributable to the decline in commodity prices ($34.1 million), as well as decreased production volumes ($22.9 million). The decrease in production volumes was driven by the temporary suspension of our drilling program. The average realized oil price, excluding the effects of commodity derivative instruments, decreased from $47.62 per Bbl for the six months ended June 30, 2015 to $33.63 per Bbl for the six months ended June 30, 2016, or 29.4%. The average realized natural gas price, excluding the effects of commodity derivative instruments, decreased from $2.07 per Mcf for the six months ended June 30, 2015 to $1.22 per Mcf for the six months ended June 30, 2016, or 41.1%. The average realized natural gas liquids price, excluding the effects of commodity derivative instruments, decreased from $14.78 per Bbl for the six months ended June 30, 2015 to $11.44 per Bbl for the six months ended June 30, 2016, or 22.6%. Average daily production decreased 24.6% to 19,489 Boe per day for the six months ended June 30, 2016 as compared to 25,862 Boe per day for the six months ended June 30, 2015.

Costs and expenses

Lease operating. Lease operating expenses decreased by $7.9 million, or 32.8%, to $16.2 million for the six months ended June 30, 2016, as compared to $24.1 million for the six months ended June 30, 2015. The decrease was principally attributable to reduction in post-completion costs driven by a temporary suspension of the drilling program, operational focus on reducing recurring operating expenses, such as optimizing the usage of compressors and rental equipment, and vendor price reductions. On a per unit basis, lease operating expenses decreased $0.58 per Boe, or 11.3%, from $5.14 per Boe in the six months ended June 30, 2015 to $4.56 per Boe in the six months ended June 30, 2016.

Production and ad valorem taxes. Production and ad valorem taxes decreased by $3.5 million, or 51.5%, to $3.3 million for the six months ended June 30, 2016, as compared to $6.8 million for the six months ended June 30, 2015. The decrease was driven by a $2.4 million (48.0%) reduction in production taxes, which decreased in conjunction with the 51.6% decrease in oil and gas revenue. Production tax rates vary between states, products, and production levels; therefore, the overall blended rate is impacted by numerous factors and the mix of producing wells at any given time.

Additionally, estimated ad valorem taxes decreased $1.1 million from $1.8 million for the six months ended June 30, 2015 to $0.8 million for the six months ended June 30, 2016, reflecting lower property assessments due to lower commodity prices. The average effective rate excluding the impact of ad valorem taxes increased from 4.5% for the six months ended June 30, 2015 to 4.8% for the six months ended June 30, 2016.

Exploration. Exploration expense decreased from $0.6 million for the six months ended June 30, 2015 to $0.2 million for the six months ended June 30, 2016. Spending during 2016 primarily related to geological data and seismic processing associated with unproved acreage. No exploratory wells were drilled during either year.

Depreciation, depletion and amortization. Depreciation, depletion and amortization decreased by $23.5 million, or 22.7%, to $79.9 million for the six months ended June 30, 2016, as compared to $103.4 million for the six months ended June 30, 2015. The decrease was primarily the result of lower production caused by a reduction in capital spending driven by a temporary suspension of the drilling program. On a per unit basis, depletion expense increased $0.44 per Boe or 2.0% from $22.09 per Boe for the six months ended June 30, 2015 as compared to $22.53 per Boe for the six months ended June 30, 2016.

General and administrative. General and administrative expenses decreased by $2.3 million, or 12.8%, to $15.6 million for the six months ended June 30, 2016, as compared to $17.9 million for the six months ended June 30, 2015. The decrease in general and administrative expense was primarily attributable to staff and other cost reductions. Non-cash compensation expense remained consistent at $3.5 million for the six months ended June 30, 2016 and 2015. On a per unit basis, general and administrative expenses, excluding non-cash items, increased from $2.87 per Boe for the six months ended June 30, 2015 to $3.11 per Boe for the six months ended June 30, 2016 primarily due to production declines.

Other operating expense. Other operating expense decreased from $4.2 million for the six months ended June 30, 2015 to none for the six months ended June 30, 2016. Expense for the six months ended June 30, 2015 represents stand-by rig costs associated with the early termination of drilling rig contracts. There were no similar charges during 2016.

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Interest expense. Interest expense decreased by $3.2 million, or 10.4%, to $27.6 million for six months ended June 30, 2016, as compared to $30.8 million for the six months ended June 30, 2015. The decrease was driven by a reduction in the outstanding balance of the 2022 Notes and the 2023 Notes as a result of our debt extinguishments. During the six months ended June 30, 2016, borrowings under the Revolver, the 2022 Notes and the 2023 Notes bore interest at a weighted average rate of 2.43%, 6.75% and 9.25%, respectively. Average outstanding balances for the six months ended June 30, 2016 were $164.0 million, $431.5 million and $182.8 million under the Revolver, the 2022 Notes and the 2023 Notes, respectively.

Gain on debt extinguishment. The gain on debt extinguishment of $99.5 million for the six months ended June 30, 2016 was related to the purchase of an aggregate principal amount of $190.9 million of our senior unsecured notes for cash of $84.6 million. The company recognized accelerated amortization of debt issuance costs of $6.7 million associated with the cancellation. See Note 4, Long-Term Debt, for further details regarding the debt extinguishment. There were no similar gains during 2015.

Net gain (loss) on commodity derivatives. The net gain (loss) on commodity derivatives was a net loss of $22.8 million for the six months ended June 30, 2016, as compared to a net gain of $21.2 million for the six months ended June 30, 2015. The loss was driven by higher average crude oil prices ($39.55 per barrel) for the six months ended June 30, 2016, as compared to the crude oil prices as of December 31, 2015 ($37.13 per barrel) as well as additional hedging activity during 2016.

Other income (expense). Other income (expense) increased by $1.5 million to net expense of $0.1 million for the six months ended June 30, 2016, as compared to a net expense of $1.6 million for the six months ended June 30, 2015. Other income (expense) for the six months ended June 30, 2016 related to an increase in the TRA valuation allowance which resulted in income of $0.2 million, partially offset by financing costs which resulted in expenses of $0.3 million. Other income (expense) for the six months ended June 30, 2015 related to financing costs which resulted in expenses of $2.3 million, partially offset by the receipt of dividend income of $0.7 million from our investment in Monarch Natural Gas Holdings, LLC.

Income taxes. The provision for federal and state income taxes for the six months ended June 30, 2016 was a benefit of $1.7 million resulting in an 14.3% effective tax rate as a percentage of our pre-tax book income year-to-date as compared to a benefit of $11.1 million for the six months ended June 30, 2015. Our effective tax rate is based on the statutory rate applicable to the U.S. and the blended rate of the states in which we conduct business and is adjusted from the enacted rates for the share of net income allocated to the non-controlling interest. The change in effective tax rate was due primarily to the percentage of income allocated to the non-controlling interest. See Note 9, Income Taxes, for further details.

Liquidity and Capital Resources

Historically, our primary sources of liquidity have been private and public sales of our debt and equity, borrowings under bank credit facilities and cash flows from operations. Our primary use of capital has been for the exploration, development and acquisition of oil and gas properties. As we pursue reserves and production growth, we continually consider which capital resources, including equity and debt financings, are available to meet our future financial obligations, planned capital expenditure activities and liquidity requirements. Our 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 (as defined below), 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 June 30, 2016 reflects a positive working capital balance largely due to the value of our current commodity derivative assets as of this date. We have historically and in the future expect to maintain a negative working capital balance, and we use our Revolver to help manage our working capital.

Availability under the Revolver is subject to a borrowing base. Our borrowing base at June 30, 2016 was $510 million of which $185.0 million was utilized leaving an unused capacity of $325.0 million. The borrowing base will be re-determined at least semi-annually on or about April 1 and October 1 of each year, with such re-determination based primarily on reserve reports using lender commodity price expectations at such time. Any reduction in the borrowing base will reduce our liquidity, and, if the reduction results in the outstanding amount under our Revolver exceeding the borrowing base, we will be required to repay the deficiency within a short period of time. The borrowing base was reduced to $410.0 million effective August 1, 2016, with an increase to $425.0 million upon closing of the Pending Anadarko Acquisition. See Note 14, Subsequent Events for further details.

The Revolver also contains a covenant which restricts the ability of Jones Energy, Inc. to (i) hold any assets, (ii) incur, create, assume, or suffer to exist any debt or any other liability or obligation, (iii) create, make or enter into any investment or (iv) engage in any other activity or operation other than, among other exceptions described therein, its ownership of equity interests in JEH and the activities of a passive holding company and assets and operations incidental thereto (including the maintenance of cash and reserves for the payment of operational costs and expenses).

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Jones Energy, Inc. and its consolidated subsidiaries are also required under the Revolver to maintain the following financial ratios:

- a total leverage ratio, consisting of consolidated debt to EBITDAX, of not greater than 4.00 to 1.00 as of the last day of any fiscal quarter; and

- a current ratio, consisting of consolidated current assets, including the unused amounts of the total commitments, to consolidated current liabilities, of not less than 1.0 to 1.0 as of the last day of any fiscal quarter.

As of June 30, 2016, our total leverage ratio is approximately 3.2 and our current ratio is approximately 6.2, as calculated based on the requirements in our covenants. We are in compliance with all terms of our Revolver at June 30, 2016, and we expect to maintain compliance throughout 2016. However, factors including those outside of our control, such as commodity price declines, may prevent us from maintaining compliance with these covenants, at future measurement dates in 2016 and beyond. In the event it were to become necessary, we believe we have the ability to take actions that would prevent us from failing to comply with our covenants, such as hedge restructuring. If an event of default exists under the Revolver, the lenders will be able to accelerate the obligations outstanding under the Revolver and exercise other rights and remedies. Our Revolver contains customary events of default, including the occurrence of a change of control, as defined in the Revolver.

Our capital budget is primarily focused on the development of the Cleveland formation through exploitation and development. The amount of capital we expend may fluctuate materially based on the market conditions for commodity prices and costs of drilling and completing wells, the economic returns being realized and the success of our drilling results as the year progresses.

On May 24, 2016, the Company and Jones Energy Holdings, LLC entered into an Equity Distribution Agreement with Citigroup Global Markets Inc. and Wells Fargo Securities, LLC (each, a Manager and collectively, the Managers). Pursuant to the terms of the Equity Distribution Agreement, the Company may sell from time to time through the Managers, as the Company s sales agents, the Company s Class A common stock having an aggregate offering price of up to $73.0 million (the Class A Shares). Under the terms of the Equity Distribution Agreement, the Company may also sell Class A Shares from time to time to any Manager as principal for its own account at a price to be agreed upon at the time of sale. Any sale of Class A Shares to a Manager as principal would be pursuant to the terms of a separate terms agreement between the Company and such Manager. Sales of the Class A Shares, if any, will be made by means of ordinary brokers transactions, to or through a market maker or directly on or through an electronic communication network, a dark pool or any similar market venue, or as otherwise agreed by the Company and one or more of the Managers.

During the six months ended June 30, 2016, the Company sold approximately 0.3 million Class A Shares under the Equity Distribution Agreement for net proceeds of approximately $1.1 million ($1.3 million gross proceeds, net of approximately $0.2 million in commissions and professional services expenses). The Company used the net proceeds for general corporate purposes. At June 30, 2016, approximately $71.7 million in aggregate offering price remained available to be issued and sold under the Equity Distribution Agreement.

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 to 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 continuously 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 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 six months ended June 30, 2016 and 2015:

	Six Months Ended June 30,	
(in thousands of dollars)	**2016**	**2015**
Net cash provided by operating activities	$ 6,000	$ 73,343
Net cash provided by / (used in) investing activities	50,047	(161,775)
Net cash (used in) / provided by financing activities	(18,642)	97,741
Net increase in cash	$ 37,405	$ 9,309

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Cash flow provided by operating activities

Net cash provided by operating activities was $6.0 million during the six months ended June 30, 2016 as compared to net cash provided by operating activities of $73.3 million during the six months ended June 30, 2015. The decrease in operating cash flows was primarily due to the $57.0 million decrease in oil and gas revenues for the six months ended June 30, 2016 as compared to the six months ended June 30, 2015, driven by declines in production volumes as a result of the temporary suspension of the drilling program, as well as declines in commodity prices.

Cash flow provided by / (used in) investing activities

Net cash provided by investing activities was $50.0 million during the six months ended June 30, 2016 as compared to net cash used in investing activities of $161.8 million during the six months ended June 30, 2015. The increase in investing cash flow was primarily driven by the reduction in capital spending, resulting from a temporary suspension of the drilling program.

Cash flow (used in) / provided by financing activities

Net cash used in financing activities was $18.6 million during the six months ended June 30, 2016 as compared to net cash provided by financing activities of $97.7 million during the six months ended June 30, 2015. The decrease in financing cash flows was primarily due to the purchase of an aggregate principal amount of $190.9 million of our senior unsecured notes for cash of $84.6 million. The Company used cash on hand and borrowings from its Revolver to fund the note purchases. Additionally, we paid cash tax distributions of approximately $10.1 million to Pre-IPO Owners. Borrowings under the Revolver totaled $75.0 million during the six months ended June 30, 2016. Cash flows from financing activities were modestly impacted by sales of Class A Shares under the Equity Distribution Agreement. During the six months ended June 30, 2016, we sold approximately 0.3 million Class A Shares for net proceeds of approximately $1.1 million ($1.3 million gross proceeds, net of approximately $0.2 million in commissions and professional services expenses).

Contractual Obligations

The holders of JEH Units, including Jones Energy, Inc., incur U.S. federal, state and local income taxes on their share of any taxable income of JEH. Under the terms of its operating agreement, JEH is generally required to make quarterly pro-rata cash tax distributions to its unitholders (including us) based on income allocated to its unitholders through the end of each relevant quarter, as adjusted to take into account good faith projections by the Company of taxable income or loss for the remainder of the calendar year, to the extent JEH has cash available for such distributions and subject to certain other restrictions. This tax distribution is computed based on the estimate of net taxable income of JEH allocated to the holders of JEH Units multiplied by the highest marginal effective rate of federal, state and local income tax applicable to an individual resident in New York, New York, without regard for the federal benefit of the deduction for any state taxes.

Based on our 2016 capital budget, debt extinguishment through July 29, 2016, and other information available as of this filing, we estimate that the total amount of tax distributions to JEH unitholders in 2016 would be approximately $42.4 million, including the approximately $20.0 million that has been paid to date. The distributions are to be made pro-rata to all members, and would result in a $22.6 million payment to the Company, and a $19.8 million payment to Pre-IPO Owners. The 2016 tax distributions are the result of taxable income generated by our operations and debt extinguishment, and our current projections do not currently lead us to anticipate payment of such tax distribution obligations beyond the current year

There have been no other material changes in our contractual obligations as reported in our Annual Report on Form 10-K for the year ended December 31, 2015.

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, 2015.

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, 2015, as well as with the unaudited consolidated financial statements and notes included in this Quarterly Report.

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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.

Potential Impairment of Oil and Gas Properties

Oil and natural gas prices are inherently volatile and have decreased significantly since 2014. Depressed commodity prices have continued into 2016, and historically low commodity prices may exist for an extended period. In applying the prescribed impairment test under the successful efforts method at June 30, 2016, no impairment charge was indicated.

Our revenues and net income are sensitive to crude oil, NGL and natural gas prices which have been and are expected to continue to be highly volatile. The recent volatility in crude oil and natural gas prices increases the uncertainty as to the impact of commodity prices on our estimated proved reserves. Although we are unable to predict future commodity prices, a prolonged period of depressed commodity prices may have a significant impact on the volumetric quantities of our proved reserves. The impact of commodity prices on our estimated proved reserves can be illustrated as follows: if the prices used for our December 31, 2015 Reserve Report had been replaced with the unweighted arithmetic average of the first-day-of-the-month prices for the applicable commodity for the trailing 12-month period ended June 30, 2016 (without regard to our commodity derivative positions and without assuming any change in development plans, costs, or other variables), then estimated proved reserves volumes as of December 31, 2015 would have decreased by approximately 2.2%. The use of this pricing example is for illustration purposes only, and does not indicate management s view on future commodity prices, costs or other variables, or represent a forecast or estimate of the actual amount by which our proved reserves may fluctuate when a full assessment of our reserves is completed as of December 31, 2016.

Periodic revisions to the estimated reserves and related future cash flows may be necessary as a result of a number of factors, including changes in oil and natural gas prices, reservoir performance, new drilling and completion, purchases, sales and terminations of leases, drilling and operating cost changes, technological advances, new geological or geophysical data or other economic factors. All of these factors are inherently estimates and are inter dependent. While each variable carries its own degree of uncertainty, some factors, such as oil and natural gas prices, have historically been highly volatile and may be highly volatile in the future. This high degree of volatility causes a high degree of uncertainty associated with the estimation of reserve quantities and estimated future cash flows. Therefore, future results are highly uncertain and subject to potentially significant revisions. Accordingly, reserve estimates are generally different from the quantities of oil and natural gas that are ultimately recovered. We cannot predict the amounts or timing of future reserve revisions, as such revisions could be negatively impacted by:

- Declines in commodity prices or actual realized prices below those assumed for future years;
- Increases in service costs;
- Increases in future global or regional production or decreases in demand;

- Increases in operating costs;
- Reductions in availability of drilling, completion, or other equipment.

If such revisions are significant, they could significantly affect future amortization of capitalized costs and result in an impairment of assets that may be material. Any future impairments are difficult to predict, and although it is not reasonably practicable to quantify the impact of any future impairments at this time, such impairments may be significant.

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 June 30, 2016 was a net asset of $120.6 million.

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Interest rate risk

We are subject to market risk exposure related to changes in interest rates on our variable rate indebtedness. The terms of the senior secured revolving credit facility 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% depending on the base rate used and the amount of the loan outstanding in relation to the borrowing base. The base rate margins under the terminated term loan were 6.0% to 7.0% depending on the base rate used and the amount of the loan outstanding. The terms of our senior notes provide for a fixed interest rate through their respective maturity dates. During the three months ended June 30, 2016, borrowings under the Revolver, the 2022 Notes and the 2023 Notes bore interest at a weighted average rate of 2.25%, 6.75% and 9.25%, respectively. During the six months ended June 30, 2016, borrowings under the Revolver, the 2022 Notes and the 2023 Notes bore interest at a weighted average rate of 2.43%, 6.75% and 9.25%, respectively.

Item 4. Controls and Procedures

Changes in Internal Control over Financial Reporting

There have been no changes in internal control over financial reporting during the quarter ended June 30, 2016 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.

Based on this evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were not effective as of June 30, 2016 because of the material weakness in internal control over financial reporting described in our Annual Report on Form 10-K for the year ended December 31, 2015.

Management s Assessment of Internal Control over Financial Reporting

The SEC, as required by Section 404 of the Sarbanes-Oxley Act, adopted rules requiring every public company that files reports with the SEC to include a management report on such company s internal control over financial reporting in its annual report. Pursuant to the Jumpstart Our Business Startups Act of 2012 (the JOBS Act), our independent registered public accounting firm will not be required to attest to the effectiveness of our internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002 for up to five years or through such earlier date that we are no longer an emerging growth company as defined in the JOBS Act. Our Annual Report on Form 10-K for the year ended December 31, 2015 included a report of management s assessment regarding internal control over financial reporting.

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PART II OTHER INFORMATION

Item 1. Legal Proceedings

For a discussion of legal proceedings, see Note 13 Commitments and contingencies, in the Notes to Consolidated Financial Statements for further discussion 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, 2015, 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.

For a discussion of our potential risks and uncertainties, see the information in Item 1A. Risk Factors in our Annual Report on Form 10-K for the year ended December 31, 2015 and our Quarterly Report on Form 10-Q for the three months ended March 31, 2016. There have been no material changes in our risk factors from those described in our Annual Report or our Quarterly Report for the three months ended March 31, 2016.

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

None.

Item 3. Defaults Upon Senior Securities

None.

Item 4. Mine Safety Disclosures

Not applicable.

Item 5. Other Information

Not applicable.

Item 6. Exhibits

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

* - filed herewith

** - furnished herewith

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SIGNATURES

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

Jones Energy, Inc.

(registrant)

Date: August 5, 2016	By:	/s/ Robert J. Brooks	
		Name:	Robert J. Brooks
		Title:	Chief Financial Officer (Principal Financial Officer)

Signature Page to Form 10-Q (Q2 2016)