Jones Energy, Inc.
Form 10-K
February 28, 2019
Table of Contents

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10 K

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

For the fiscal year ended: December 31, 2018

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

For the transition period from to

Commission file number: 001 36006

Jones Energy, Inc.

(Exact name of registrant as specified in its charter)

Delaware	80 0907968
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

807 Las Cimas Parkway, Suite 350

Austin, Texas 78746

(Address of principal executive offices) (Zip Code)

Tel: (512) 328 2953

Registrant’s telephone number, including area code

Securities registered pursuant to Section 12(b) of the Exchange Act:

Title of class	Name of each exchange on which registered
Class A Common Stock, $0.001 par value	N/A

Securities registered pursuant to Section 12(g) of the Exchange Act: None

Indicate by check mark if the registrant is a well known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes No

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 No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S T during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10 K or any amendment to this Form 10 K.

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," "smaller reporting company" and "emerging growth company" in Rule 12b 2 of the Exchange Act.

Large accelerated filer Accelerated filer

Non accelerated filer Smaller reporting company
Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

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

The aggregate market value of the voting and non-voting common stock held by non-affiliates of the registrant computed as of June 29, 2018 (the last business day of the Registrant's most recently completed second fiscal quarter) based on the closing price of the Class A common stock as reported by the New York Stock Exchange was $20.3 million.

There were 5,826,217 and 172,193 shares of the registrant's Class A and Class B common stock, respectively, outstanding on February 20, 2019.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement for the 2019 Annual Meeting of Stockholders, to be filed no later than 120 days after the end of the fiscal year, which we refer to as the Proxy Statement, are incorporated by reference into Part III of this Annual Report on Form 10 K.

Table of Contents

JONES ENERGY, INC.

TABLE OF CONTENTS

PART 1	
Item 1. Business	3
Item 1A. Risk Factors	23
Item 1B. Unresolved Staff Comments	47
Item 2. Properties	47
Item 3. Legal Proceedings	47
Item 4. Mine Safety Disclosures	47
PART II	
Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities	48
Item 6. Selected Financial Data	49
Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations	53
Item 7A. Quantitative and Qualitative Disclosures about Market Risk	69
Item 8. Financial Statements and Supplementary Data	70
Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	70
Item 9A. Controls and Procedures	70
Item 9B. Other Information	71
PART III	
Item 10. Directors, Executive Officers and Corporate Governance	72
Item 11. Executive Compensation	72
Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters	72
Item 13. Certain Relationships and Related Transactions, and Director Independence	72
Item 14. Principal Accounting Fees and Services	72
PART IV	
Item 15. Exhibit Index	73
Item 16. Form 10-K Summary	77
Signatures	78
Financial Statements	
Balance Sheets	F 4
Statements of Operations	F 5
Statement of Changes in Stockholders' Equity	F 6
Statements of Cash Flows	F 7
Notes to the Consolidated Financial Statements	F 8

Table of Contents

Cautionary Statement Regarding Forward Looking Statements

The information in this Annual Report on Form 10 K (the “Annual Report”), includes “forward looking statements.” All statements, other than statements of historical fact included in this report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward looking statements. When used in this Annual Report, the words “could,” “should,” “will,” “may,” “believe,” “anticip “intend,” “estimate,” “expect,” “project” and similar expressions are intended to identify forward looking statements, althougl not all forward looking statements contain such identifying words. These forward looking statements are based on our current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward looking statements, you should keep in mind the risk factors and other cautionary statements described under the heading “Risk Factors” included in this report. These forward looking statements are based on management’s current belief, based on currently available information, as to the outcome and timing of future events, actions and developments including:

- business strategy;
- estimated current and future net reserves and the present value thereof, and the likelihood of establishing production from such estimates;
- drilling and completion of wells including our identified drilling locations;
- cash flows, liquidity and our leverage;
- financial strategy, capital and operating budgets, projections and operating results;
- future prices and change in prices for oil, natural gas and NGLs;
- customers’ elections to reject ethane and include it as part of the natural gas stream;
- timing and amount of future production of oil and natural gas;
- availability and cost of drilling, completion and production equipment;
- availability and cost of oilfield labor;
- the amount, nature and timing of capital expenditures, including future development costs;
- ability to fund our 2019 capital expenditure budget;
- availability and terms of capital;
- development results from our identified drilling locations;
- ability to generate returns and pursue opportunities;
- marketing of oil, natural gas and NGLs;
- property acquisitions and dispositions and realizing the expected benefits or effects of completed acquisitions and dispositions;
- the availability, cost and terms of, and competition for mineral leases and other permits and rights of way and our ability to maintain mineral leases;
- costs of developing our properties and conducting other operations, including costs associated with our operations in the Merge area as compared to our operations in the Cleveland play;
- general economic conditions, including the levels of supply and demand for oil, natural gas and NGLs, and the commodity price environment;

Table of Contents

- competitive conditions in our industry;
- effectiveness and extent of our risk management activities;
- estimates of future potential impairments;
- environmental and endangered species regulations and liabilities;
- counterparty credit risk;
- the extent and effect of any hedging activities engaged in by us;
- the impact of, and changes in, governmental regulation of the oil and natural gas industry, including tax laws and regulations, environmental, health and safety laws and regulations, and laws and regulations with respect to derivatives and hedging activities;
- developments in oil producing and natural gas producing countries;
- uncertainty regarding our future operating results;
- negative impacts from our delisting from a national securities exchange;
- weather, including its impact on oil and natural gas demand and weather related delays on operations;
- changes and uncertainties regarding technology;
- plans, objectives, expectations and intentions contained in this report that are not historical; and
- other factors that are described under Risk Factors in Item 1A of this form 10-K.

We caution you that these forward looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development and production of oil and natural gas. These risks include, but are not limited to, commodity price levels and volatility, inflation, the cost of oil field equipment and services, lack of availability of drilling, completion and production equipment and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating oil and natural gas reserves and in projecting future rates of production, cash flow and access to capital, the timing of development expenditures, and the other risks described under “Risk Factors” in this report.

Reserve engineering is a process of estimating underground accumulations of oil and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reservoir engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of oil and natural gas that are ultimately recovered.

Should one or more of the risks or uncertainties described in this report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward looking statements.

All forward looking statements, expressed or implied, included in this report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this report.

Table of Contents

References

Unless indicated otherwise in this Annual 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. is a holding company whose sole material asset is an equity interest in Jones Energy Holdings, LLC.

PART 1

Item 1. Business

Organization

Jones Energy, Inc. was formed in March 2013 as a Delaware corporation to become a publicly-traded entity and the holding company of Jones Energy Holdings, LLC. 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.

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 remaining owners of JEH prior to the initial public offering (“IPO”) of the Company (collectively, the “Class B shareholders”) and can be exchanged (together with a corresponding number of common 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. In addition, the Company’s certificate of incorporation also authorizes the Board of Directors of the Company (the “Board”) to establish one or more series of preferred stock. On August 25, 2016, the Company issued 1,840,000 shares of its 8.0% Series A Perpetual Convertible Preferred Stock, par value $0.001 per share (the “Series A preferred stock”), pursuant to a registered public offering, of which 1,804,478 remained isused and outstanding as of December 31, 2018.

Jones Energy, Inc.’s Class A common stock is quoted on the OTCQX, which is the highest market tier operated by the OTC Markets Group, Inc., under the ticker symbol “JONE.” Neither the Class B common stock nor the Series A preferred stock are listed securities.

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 Oklahoma and Texas. Our Chairman of the Board, 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 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 Basin, having concentrated our operations there for over 25 years. We have drilled approximately 970 total wells as an operator, including over 790 horizontal wells, since our formation. Our operations are focused on horizontal drilling within two distinct areas in Oklahoma and Texas:

- the Eastern Anadarko Basin—targeting the liquids rich Woodford shale and Meramec formations in the Merge area of the STACK/SCOOP plays (the “Merge”); and
- the Western Anadarko Basin—targeting the liquids rich Cleveland, Marmaton, Granite Wash and Tonkawa formations.

We seek to optimize returns through a disciplined emphasis on controlling costs and promoting operational efficiencies, and we have historically been recognized as one of the lowest-cost drilling and completion operators in the Cleveland formation. Our low-cost drilling expertise has applied directly to our newer operations in the Merge, where the Company plans to spend the majority of its 2019 capital budget.

The Anadarko Basin is among the most prolific and largest onshore oil and natural gas basins in the United States, characterized by multiple producing horizons and extensive well control collected over 100 years of development. We leverage our extensive geologic experience in the basin and seek to identify the most profitable exploration and

Table of Contents

development opportunities to apply our operational expertise. The formations we target are generally characterized by oil and/or liquids rich natural gas content, extensive production histories, long lived reserves, high drilling success rates and attractive initial production rates. We focus on formations in our operating areas that we believe offer significant development potential and to which we can apply our technical experience and operational excellence to increase reserves, production and cash flows. Our goal is to build value through a disciplined balance between developing our current inventory of 8,187 gross (2,017 net) identified drilling locations, identifying new opportunities within our existing asset base, actively pursuing organic leasing, and acquisition opportunities.

As of December 31, 2018, our total estimated proved reserves were 68.0 MMBoe, of which 90% were classified as proved developed reserves. Approximately 23% of our total estimated proved reserves as of December 31, 2018 consisted of oil, 32% consisted of NGLs, and 45% consisted of natural gas. As of December 31, 2018, our properties included 1,084 gross producing wells. For the three years ended December 31, 2018, we drilled 138 wells as operator. The following table presents summary reserve, acreage and production data for each of our core operating areas:

	As of December 31, 2018 Estimated Net Proved Reserves			Acreage		Year Ended December 31, 2018 Average Daily Net Production		
	MMBoe	% Oil and NGLs		Gross Acreage	Net Acreage	MBoe/d	% Oil and NGLs	
Western Anadarko (1)	45.0	56	%	201,841	146,169	13.1	59	%
Eastern Anadarko (2)	22.9	53	%	152,561	22,659	8.5	57	%
Other	0.1	41	%	19,287	16,925	1.1	36	%
All properties	68.0	55	%	373,689	185,753	22.7	57	%

(1) Western Anadarko includes the Cleveland, Granite Wash, Tonkawa and Marmaton formations.
(2) Eastern Anadarko consists of the Merge Meramec and Woodford formations.

The following table presents summary well and drilling location data for each of our key formations for the date indicated:

	As of December 31, 2018 Producing Wells		Identified Drilling Locations (1)	
	Gross	Net	Gross	Net
Western Anadarko	901	553	1,669	845
Eastern Anadarko	163	38	6,506	1,168
Other	20	6	12	4
All properties	1,084	597	8,187	2,017

(1) Our total 8,187 identified drilling locations includes contingent locations. There are 3,928 gross total proved undeveloped, probable and possible drilling locations, of which 137 gross locations are associated with proved undeveloped reserves as of December 31, 2018. We have estimated our drilling locations based on well spacing

assumptions for the areas in which we operate and other criteria. See “Business—Development of Proved Undeveloped Reserves” and “Business—Drilling Locations” for more information regarding our proved undeveloped reserves and the processes and criteria through which these drilling locations were identified.

Our 2018 capital expenditures totaled $192.6 million (excluding the impact of asset retirement costs, asset disposals and non-cash impairments of oil and gas properties), of which $149.5 million was utilized to drill and complete operated wells. The Company has established an initial capital budget of $60.0 million for 2019, including $48.0 million for drilling and completing wells and $12.0 million for workovers, leasing, and other capital projects. Please see “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources.”

We expect to fund our 2019 budgeted capital expenditures with cash flow from operations, as well as potential non-strategic asset sales or potentially accessing the debt and/or equity capital markets. In addition, we may, from time to time and subject to our assessment of market conditions, engage in liability management transactions in an effort to

Table of Contents

reduce indebtedness. Furthermore, we expect to develop all drilling locations classified as proved undeveloped reserves in the year end reserve report within five years of initial proved reserve booking. We consider projections of future commodity prices when determining our development plan, but many other factors are also considered. Should the commodity price environment or other material factors change significantly from current levels, we will re evaluate our development plan at that time. If the evaluation results in a shifting of capital expenditures into future periods beyond five years from the initial proved reserve booking, it could potentially lead to a reduction in proved undeveloped reserves.

We have allocated our 2019 capital expenditure budget as follows:

(in millions of dollars)	2019 Capital Expenditure Budget
Drilling and completion	
Western Anadarko	$ 15.0
Eastern Anadarko	33.0
Total drilling and completion	$ 48.0
Other activities (leasing, pooling, maintenance)	12.0
All properties and activities	$ 60.0

Recent Developments

See Note 18, “Subsequent Events,” in the Notes to Consolidated Financial Statements for discussion of recent developments.

Our Operations

Our Area of Operations

We own leasehold interests in oil and natural gas producing properties, as well as in undeveloped acreage, substantially all of which are located in the Anadarko Basin in Oklahoma and Texas. The majority of our interests are in producing properties located in fields characterized by what we believe to be long lived, predictable production profiles and repeatable development opportunities. Specifically, our properties and wells are located in fields that generally have been developed over a long period of time, typically decades. Given the long productive history of these fields, there is substantial midstream and service infrastructure in place, including natural gas and NGL pipelines and natural gas processing plants. Observing the performance of these fields over many years allows for greater understanding of production and reservoir characteristics, making future performance more predictable. For a discussion of the risks inherent in oil and natural gas production, please read “Risk Factors—Drilling for and producing oil, natural gas and NGLs are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.”

Nearly 100% of our estimated proved reserves as of December 31, 2018 and approximately 95% of our average daily net production for the year ended December 31, 2018 were located in the Anadarko Basin. The Anadarko Basin is one of the most prolific oil and natural gas producing basins in the United States, covering approximately 50,000 square miles primarily in Oklahoma, but also including the upper Texas Panhandle, southwestern Kansas, and southeastern Colorado.

The Anadarko Basin has an especially well developed interval of productive Pennsylvanian age sedimentary rocks, up to 15,000 feet thick. Our wells in this area produce oil, natural gas and NGLs from various formations at depths from approximately 7,000 feet to 14,000 feet. We drilled 21 gross (16 net) wells as operator in the Anadarko Basin during 2018. Our operations in the Western Anadarko Basin have been primarily focused on the Cleveland formation where we have 630 producing wells. We also have acreage in the Marmaton, Tonkawa, Granite Wash, and various Pennsylvanian age shale formations located in western Oklahoma and the eastern portion of the Texas Panhandle. Since 2016, we have also been focused on the Woodford and Meramec formations in the Eastern Anadarko Basin.

Our production in the Anadarko Basin is currently derived primarily from the following formations, where we have 1,064 gross (591 net) producing wells and where we have identified 8,175 gross (2,013 net) drilling locations as of December 31, 2018, of which 137 have proved undeveloped reserves attributed to them as of December 31, 2018. See

Table of Contents

"Drilling Locations" for more information regarding the processes and criteria through which these drilling locations were identified.

Western Anadarko Basin.

· Cleveland Formation. Our Cleveland acreage is primarily located in Ochiltree, Lipscomb, Hutchinson, and Hemphill Counties in Texas and Ellis County in Oklahoma. The Cleveland formation ranges from depths of approximately 7,000 feet to 8,800 feet and is characterized by a tight, shaly sand with low permeability that lends itself to improved recovery through enhanced drilling and completion techniques.

As of December 31, 2018, we had 630 gross (461 net) producing wells in the formation with an average working interest of 73%, of which we operated 471 gross (401 net) producing wells. Our Cleveland properties contained 40.4 MMBoe of estimated net proved reserves as of December 31, 2018, 58% of which are oil and NGLs, and generated an average daily net production of 13.1 MBoe/d for the year ended December 31, 2018. We have identified 550 gross (371 net) drilling locations in the Cleveland formation as of December 31, 2018. Of these 550 locations, no locations have proved undeveloped reserves attributed to them as of December 31, 2018.

· Marmaton Formation. As of December 31, 2018, we identified 487 gross (286 net) drilling locations in the Marmaton formation. Our properties in the Marmaton formation are all undeveloped and span three sub-formations: properties located primarily in Ellis County, Oklahoma characterized by fluvio-deltaic sands, properties located primarily in Northeast Ochiltree and Northwest Lipscomb Counties, Texas, characterized by shallow marine sands, and properties located primarily in Ochiltree County, Texas characterized by algal reef complex. The Marmaton sand is a tight, shaly sand with similar reservoir characteristics to the Cleveland. The Marmaton sand ranges in thickness from 40 feet to 80 feet while the reef ranges from 80 feet to 150 feet.

We drilled two horizontal Marmaton wells in 2018 in Ochiltree County, Texas. As of December 31, 2018, our Marmaton properties contained 0.4 MMBoe of estimated net proved reserves.

· Tonkawa Formation. As of December 31, 2018, we identified 279 gross (168 net) drilling locations in the Tonkawa formation primarily in Lipscomb and Hemphill Counties in Texas. In addition, the Tonkawa formation is present in the area of other properties we own located primarily in Ellis and Roger Mills Counties in Oklahoma. The Tonkawa is a horizontal oil formation at depths of approximately 6,000 feet to 8,000 feet and is characterized by fine to very fine grained shallow marine sandstone, ranging in thickness from 20 feet to 40 feet.

We drilled our first horizontal Tonkawa well in May 2010 and drilled two additional horizontal wells in the formation under a farm out with Samson Resources that is not part of our current leasehold. During 2014, we drilled six additional test wells in different areas of the Company's leasehold acreage in the Tonkawa formation. As of December 31, 2018, our Tonkawa properties contained 0.3 MMBoe of estimated net proved reserves.

· Granite Wash Formation. Our Granite Wash acreage is primarily located in Roberts, Hemphill and Wheeler Counties in Texas and Roger Mills, Beckham, Custer and Washita Counties in Oklahoma. The Granite Wash spans multiple zones from depths of approximately 9,000 feet to 12,000 feet and is composed of stacked, low permeability, variable lithology alluvial fan deltaic deposits.

As of December 31, 2018, we had 74 gross (19 net) producing wells in the formation with an average working interest of 26%, of which we operated 23 gross (17 net) producing wells. Our Granite Wash properties contained 2.2 MMBoe of estimated net proved reserves as of December 31, 2018, approximately 45% of which are oil and NGLs. We have 362 gross (22 net) remaining drilling locations in the Granite Wash formation as of December 31, 2018.

Eastern Anadarko Basin.

· Meramec Formation. Our Meramec acreage is located in Canadian, Grady and McClain Counties in Oklahoma. The Meramec is a horizontal liquid-rich reservoir that ranges in depths from approximately

6

Table of Contents

8,000 feet to 12,500 feet. The reservoir includes various fluids from black oil to gas/condensate. The Meramec formation consist of siltstones, organic-rich shale, and limestones with gradations between rock types. Early results from laterals drilled in various landing points within the Meramec indicate the rock is highly conducive to improved recovery from enhanced drilling and completion techniques.
Our Meramec properties contained 11.9 MMBoe of estimated net proved reserves as of December 31, 2018, approximately 54% of which are oil and NGLs, and generated an average daily net production of 4.9 MBoe/d for the year ended December 31, 2018. We have identified 3,268 gross (578 net) drilling locations in the Meramec formation as of December 31, 2018. Of these 3,268 locations, 51 locations (3%) have proved undeveloped reserves attributed to them as of December 31, 2018.

- Woodford Formation. Our Merge Woodford acreage is located in Canadian, Grady and McClain Counties in Oklahoma. The Merge Woodford ranges in depths from approximately 8,500 feet to 13,000 feet and includes various fluids from black oil to gas/condensate. The Merge Woodford formation consists of siliceous, organic-rich shale, and thin bedded carbonates. The low permeability reservoir is naturally fractured with silica-rich brittle layers that are highly conducive to improved recovery from enhanced drilling and completion techniques.

Our Merge Woodford properties contained 10.9 MMBoe of estimated net proved reserves as of December 31, 2018, approximately 52% of which are oil and NGLs, and generated an average daily net production of 3.7 MBoe/d for the year ended December 31, 2018. We have identified 3,238 gross (590 net) drilling locations in the Merge Woodford formation as of December 31, 2018. Of these 3,238 locations, 85 locations (3%) have proved undeveloped reserves attributed to them as of December 31, 2018.

Future Potential Opportunities. Our current leasehold position provides longer term potential exposure to other prospective formations in the Anadarko Basin, including the Atoka, Cherokee, Douglas, Cottage Grove, and Upper and Lower Morrow formations in the Western Anadarko, and the Hunton, Osage, Chester, Caney, and Springer formations in the Eastern Anadarko. The Atoka and Cherokee formations, in particular, have attractive geologic properties, and we may elect to pursue their development in the future.

Drilling Locations

We have identified a total of 8,187 gross (2,017 net) drilling locations on our acreage, all of which are horizontal drilling locations. Of these total identified locations, 4,437 gross locations are attributable to acreage that is currently held by existing production, 3,928 gross locations are attributable to proved undeveloped, probable and possible drilling locations, and approximately 137 (2%) are attributable to proved undeveloped reserves as of December 31, 2018. In order to identify drilling locations, we apply geologic screening criteria based on the presence of a minimum threshold of reservoir thickness in a section and then consider the number of sections and the appropriate well density to develop the applicable field. In making these assessments, we include properties in which we hold operated and non operated interests, as well as redevelopment opportunities.

For our proved undeveloped, probable, and possible drilling locations, once we have identified acreage that is prospective for the targeted formations, well placement is determined primarily by the regulatory spacing rules prescribed by the governing body in each of our operating areas. Wells drilled in the Cleveland formation are developed ranging between 128 acre spacing (5 wells per section) and 213-acre spacing (3 wells per section). Wells drilled in the Merge Woodford formation and the Meramec formation are developed on 160 acre spacing with each formation containing two benches (4 wells per bench). Wells drilled in the Granite Wash formation are developed on 128 acre or 213 acre spacing. Wells drilled in the Tonkawa and Marmaton formations are developed on 160 acre spacing. We view the risk profiles for the Tonkawa and Marmaton formations as being higher than for our other drilling locations due to relatively less available production data and drilling history.

Our identified drilling locations are scheduled to be drilled over many years. The ultimate timing of the drilling of these locations will be influenced by multiple factors, including oil, natural gas and NGL prices, the availability and cost of capital, drilling, completion and production costs, the availability of drilling services and equipment, drilling results, lease expirations, gathering systems, processing, marketing and pipeline transportation constraints, regulatory approvals and other factors. In addition, a number of our identified drilling locations are associated with joint development agreements, and if we do not meet our obligation to drill the minimum number of wells specified in an agreement, we will lose the right to continue to develop certain acreage covered by that agreement. For a discussion of the risks

Table of Contents

associated with our drilling program, see "Risk Factors—Our identified drilling locations are scheduled to be drilled over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling, which in certain instances could prevent or delay associated expected production. In addition, we may not be able to raise the amount of capital that would be necessary to drill a substantial portion of our identified drilling locations."

Estimated Proved Reserves

The following table sets forth summary data with respect to our estimated net proved oil, natural gas and NGLs reserves as of December 31, 2018, 2017 and 2016, which are based upon reserve reports of Cawley, Gillespie & Associates, Inc., ("Cawley Gillespie"), our independent reserve engineers. Cawley Gillespie's reports were prepared in accordance with the rules and regulations of the SEC regarding oil and natural gas reserve reporting in effect during such periods.

	As of December 31,		
	2018	2017	2016
Reserve Data:			
Estimated proved reserves:			
Oil (MBbls)	15,755	29,014	23,594
Natural gas (MMcf)	183,884	255,148	283,140
NGLs (MBbls)	21,584	33,273	34,425
Total estimated proved reserves (MBoe) (1)	67,986	104,812	105,209
Estimated proved developed reserves:			
Oil (MBbls)	13,754	15,416	11,471
Natural gas (MMcf)	165,212	159,459	180,293
NGLs (MBbls)	19,699	20,181	20,941
Total estimated proved developed reserves (MBoe) (1)	60,988	62,173	62,461
Estimated proved undeveloped reserves:			
Oil (MBbls)	2,001	13,598	12,123
Natural gas (MMcf)	18,672	95,689	102,847
NGLs (MBbls)	1,885	13,092	13,484
Total estimated proved undeveloped reserves (MBoe) (1)	6,998	42,639	42,748
Standardized measure (in millions) (2)	$ 547	$ 566	$ 383
PV-10 (in millions) (3)	$ 570	$ 627	$ 401

(1) One Boe is equal to six Mcf of natural gas or one Bbl of oil or NGLs based on an approximate energy equivalency. This is a physical correlation and does not reflect a value or price relationship between the commodities.
(2) Standardized measure is calculated in accordance with ASC Topic 932, Extractive Activities—Oil and Gas.
(3) PV 10 is a non GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effect of income taxes on discounted future net cash flows. Neither PV 10 nor Standardized Measure represents an estimate of the fair market value of our oil and natural gas properties. The oil and gas industry uses PV 10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities. See "Reconciliation of PV 10 to Standardized Measure" below.

Table of Contents

The following table sets forth the benchmark prices used to determine our estimated proved reserves for the periods indicated.

	As of December 31,		
	2018	2017	2016
Oil, Natural Gas and NGLs Benchmark Prices:			
Oil (per Bbl) (1)	$ 65.56	$ 51.34	$ 42.75
Natural gas (per MMBtu) (2)	3.11	2.96	2.46
NGLs (per Bbl) (3)	25.02	18.92	17.73

(1) Benchmark prices for oil reflect the unweighted arithmetic average first day of the month prices for the prior 12 months using WTI Cushing posted prices. These prices were utilized in the reserve reports prepared by Cawley Gillespie and in management’s internal estimates and are adjusted by well for content, quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. As of December 31, 2018, 2017 and 2016, the average realized prices for oil were $62.89, $47.45 and $38.80 per Bbl, respectively.

(2) Benchmark prices for natural gas in the table above reflect the unweighted arithmetic average first day of the month prices for the prior 12 months, respectively, using Henry Hub prices. These prices were utilized in the reserve reports prepared by Cawley Gillespie and in management’s internal estimates and are adjusted by well for content, quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. As of December 31, 2018, 2017 and 2016, the average realized prices for natural gas were $1.54, $2.10 and $2.19 per MMBtu, respectively.

(3) Benchmark prices for NGLs in the table above reflects the unweighted arithmetic average first-day-of-the-month prices for the prior 12 months using 39.8% of WTI Cushing posted prices. These prices were utilized in the reserve reports prepared by Cawley Gillespie and in management’s internal estimates and are adjusted by well for content, quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead. As of December 31, 2018, 2017 and 2016, the average realized prices for NGLs were $25.01, $18.92 and $17.72 per MMBtu, respectively.

Reserves Sensitivities

Assuming NYMEX strip pricing as of February 20, 2019 through 2023 and keeping pricing flat thereafter, instead of 2018 SEC pricing, and leaving all other parameters unchanged, the Company’s proved reserves would have been 64.7 MMBoe. This alternative pricing scenario is provided only to demonstrate the impact that the current pricing environment may have on reserves volumes. There is no assurance that these prices will actually be realized. The amount of our proved reserves as of December 31, 2018 calculated using SEC pricing is higher than the amount of our proved reserves calculated using current market prices. Using SEC pricing as of December 31, 2018, our total estimated proved reserves were 68.0 MMBoe.

Reconciliation of PV 10 to Standardized Measure

PV 10 is derived from the Standardized Measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV 10 is a computation of the Standardized Measure of discounted future net cash flows on a pre tax basis. PV 10 is equal to the Standardized Measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of PV 10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our proved reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV 10, however, is not a substitute for the Standardized Measure of discounted future net cash flows. Our PV 10 measure and the Standardized Measure of discounted future net cash flows do not purport to represent the fair value of our oil and natural gas reserves.

Table of Contents

The following table provides a reconciliation of the components of the Standardized Measure of discounted future net cash flows to PV 10 at December 31, 2018, 2017 and 2016.

	As of December 31,		
(in millions of dollars)	2018	2017	2016
Standardized measure	$ 547	$ 566	$ 383
Present value of future income taxes discounted at 10%	23	61	18
PV-10	$ 570	$ 627	$ 401

Internal Controls

Our proved reserves are estimated at the well or unit level and compiled for reporting purposes by our corporate reservoir engineering staff. We maintain internal evaluations of our reserves in a secure reserve engineering database. The corporate reservoir engineering staff interacts with our internal petroleum engineers and geoscience professionals in each of our operating areas and with operating, accounting and marketing employees to obtain the necessary data for the reserves estimation process. Reserves are reviewed and approved internally by our senior management team on a semi annual basis. We expect to have our reserve estimates evaluated by Cawley Gillespie, our independent third party reserve engineers, or another independent reserve engineering firm, at least annually.

Our internal professional staff works closely with Cawley Gillespie to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. We provide all of the reserve information maintained in our secure reserve engineering database to the external engineers, as well as other pertinent data, such as geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures and relevant economic criteria. We make all requested information, as well as our pertinent personnel, available to the external engineers as part of their evaluation of our reserves. Various procedures are used to ensure the accuracy of the data provided to our independent petroleum engineers, including review processes. Changes in reserves from the previous report are closely monitored. Reconciliation of reserves from the previous report, which includes an explanation of all significant changes, is reviewed by both the engineering department and management, including our Executive Vice President of Geosciences and Business Development. Our independent petroleum engineers prepare our annual reserves estimates, whereas interim estimates are internally prepared.

Technology Used to Establish Proved Reserves

Under SEC rules, proved reserves are those quantities of oil and natural gas that by analysis of geoscience and engineering data can be estimated with reasonable certainty to be economically producible from a given date forward from known reservoirs, and under existing economic conditions, operating methods and government regulations. The term “reasonable certainty” implies a high degree of confidence that the quantities of oil and natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

To establish reasonable certainty with respect to our estimated proved reserves, our internal reserve engineers and Cawley Gillespie employed technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps and available downhole and production data, seismic data and well test data. Reserves attributable to producing wells with sufficient production history were estimated using appropriate decline curves or other performance relationships. Reserves attributable to producing wells with limited production history and for undeveloped locations were estimated using performance from analogous wells in the surrounding area and geologic data to assess the reservoir continuity. These wells were considered to be analogous based on production performance from the same formation and well completion using similar techniques.

Qualifications of Responsible Technical Persons

Internal technical specialist. Tracy Lenz, our Asset Manager, is the technical specialist responsible for overseeing the preparation of our reserves estimates. She has been with the Company since September 2012 and served as Reserve Engineer prior to being promoted to Asset Lead. Prior to joining Jones Energy, she worked

Table of Contents

as a petroleum engineer for Chevron for five years. Mrs. Lenz holds a Bachelor's of Science degree in Petroleum Engineering from University of Texas, a Master's of Science in Petroleum Engineering from the University of Southern California, and is a Registered Professional Engineer in the State of Texas (License No. 132654).

Cawley Gillespie. Cawley, Gillespie & Associates, Inc. is a Texas Registered Engineering Firm (F 693), made up of independent registered professional engineers and geologists. The firm has provided petroleum consulting services to the oil and gas industry for over 50 years. No director, officer, or key employee of Cawley Gillespie has any financial ownership in us or any of our affiliates. Cawley Gillespie's compensation for the required investigations and preparation of its report is not contingent upon the results obtained and reported, and Cawley Gillespie has not performed other work for us that would affect its objectivity. The reserves presented in the Cawley Gillespie report were prepared under the supervision of W. Todd Brooker, President at Cawley Gillespie. Mr. Brooker is an experienced reservoir engineer having been a practicing petroleum engineer since 1989. He has more than 25 years of experience in reserves evaluation and joined Cawley Gillespie as a reserve engineer in 1992. He has a Bachelor's of Science Degree in Petroleum Engineering from the University of Texas at Austin and is a Registered Professional Engineer in the State of Texas (License No. 83462).

Development of Proved Undeveloped Reserves

As of December 31, 2018, none of our proved undeveloped reserves at December 31, 2018 were scheduled to be developed on a date more than five years from the date the reserves were initially booked as proved undeveloped. However, certain of our proved undeveloped reserves are associated with joint development agreements with third parties that include obligations to drill a specified minimum number of wells in a time frame that is shorter than five years. If we do not meet our obligation to drill the minimum number of wells specified in a joint development agreement, we will lose the right to continue to develop the undeveloped acreage covered by the agreement, which in some cases would result in a reduction in our proved undeveloped reserves. Historically, our drilling and development programs were substantially funded from our cash flow from operations and the capital markets. Our expectation is to continue to fund our drilling and development programs primarily from our cash flow from operations and cash on our balance sheet, as well as potential non-strategic asset sales. Based on our current expectations of our cash resources and drilling and development programs, which include drilling of proved undeveloped locations, we believe that we will be able to fund the drilling of our current inventory of proved undeveloped locations in the next five years. For a more detailed discussion of our liquidity position, please read “Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources.”

	Total (MMBoe)
Estimated Proved Undeveloped Reserves	
December 31, 2016	42.7
Extensions and discoveries	13.8
Conversion to proved developed	(6.2)
Purchases of minerals in place	—
Sales of minerals in place	(1.6)
Revisions of previous estimates	(6.1)
December 31, 2017	42.6
Extensions and discoveries	4.2
Conversion to proved developed	(0.7)
Purchases of minerals in place	—
Sales of minerals in place	—
Revisions of previous estimates	(39.1)

December 31, 2018	7.0

We have decreased the volume of our proved undeveloped reserves year-over-year, from 42.6 MMBoe as of December 31, 2017 to 7.0 MMBoe as of December 31, 2018. The decrease was due to revisions of previous estimates, including (i) negative revisions of 23.4 MMBoe of proved undeveloped reserves due to the Company's limited capital resources available to fund our drilling program (ii) negative revisions of 10.7 MMBoe of proved undeveloped reserves rescheduled outside of five years from their initial booking due to reduced drilling and (iii) net negative revisions of 4.8 MMBoe due to lease expirations. Proved undeveloped reserves decreased as a percentage of total reserves from 41% for

Table of Contents

the year ended December 31, 2017 to 10 % for the year ended December 31, 2018. Proved undeveloped reserves remained constant as a percentage of total reserves at 41% for the years ended December 31, 2017 and 2016.

For the year ended December 31, 2018, we converted 0.7 MMBoe of proved undeveloped reserves to proved developed reserves or 1.6% of total proved undeveloped reserves booked at December 31, 2017. Our 2018 capital expenditures totaled $192.6 million (excluding the impact of asset retirement costs, asset disposals and non-cash impairments of oil and gas properties), of which $149.5 million was utilized to drill and complete operated wells, including wells that had no proved undeveloped reserves associated with them prior to drilling. The Company has established an initial capital budget of $60.0 million for 2019, with the majority dedicated to drilling and completion activities. Costs of proved undeveloped reserve development in 2018 do not represent the total costs of these conversions, as additional costs may have been incurred in previous years. Estimated future development costs relating to the development of 2018 year end proved undeveloped reserves is $61.3 million, all of which is scheduled to be incurred within five years of initial proved reserve booking. All drilling locations classified as proved undeveloped reserves in the year end reserve report are scheduled to be drilled within five years of initial proved reserve booking.

Operating Data

The following table sets forth summary data regarding production volumes, average prices and average production costs associated with our sale of oil and natural gas for the periods indicated.

	Year Ended December 31,		
	2018	2017	2016
Production and Operating Data:			
Net Production Volumes:			
Oil (MBbls)	2,241	1,964	1,685
Natural gas (MMcf)	21,384	20,425	18,842
NGLs (MBbls)	2,500	2,418	2,204
Total (MBoe)	8,305	7,786	7,029
Average net production (Boe/d)	22,753	21,332	19,205
Average Sales Price (1):			
Oil (per Bbl)	$ 63.02	$ 47.46	$ 37.83
Natural gas (per Mcf)	1.62	2.07	1.67
NGLs (per Bbl)	24.38	21.09	13.48
Combined (per Boe) realized	28.52	23.94	17.77
Average Costs per Boe:			
Lease operating	$ 5.41	$ 4.71	$ 4.64
Production and ad valorem taxes	1.46	0.88	1.11
Depreciation, depletion and amortization	20.94	21.48	21.90
General and administrative (2)	3.76	3.84	4.22

(1) Prices do not include the effects of derivative cash settlements.

(2) General and administrative includes non cash compensation of $1.4 million, $6.5 million and $8.2 million for the years ended December 31, 2018, 2017 and 2016, respectively. Excluding non-cash compensation from the above metric results in average cash general and administrative cost per Boe of $3.58, $3.01 and $3.05 for the years ended December 31, 2018, 2017 and 2016, respectively.

Table of Contents

Drilling Activity

The following table sets forth information with respect to wells drilled during the periods indicated. The information should not be considered indicative of future performance, nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found or economic value.

	Year Ended December 31,					
	2018		2017		2016	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	21	16	68	56	42	37
Mechanical failure (1)	1	1	—	—	3	3
Dry	—	—	1	1	—	—
Exploratory Wells:						
Productive	—	—	1	1	1	1
Dry	—	—	—	—	—	—
Total Wells:						
Productive	21	16	69	57	43	38
Mechanical failure (1)	1	1	—	—	3	3
Dry	—	—	1	1	—	—
Total	22	17	70	58	46	41

(1) Mechanical failures represent wells drilled during the year indicated which were classified as "Proved Developed Non-Producing" in the Reserve Report for that year, but are not currently in the process of completion at the end of the year.

For the three years ended December 31, 2018, we had one developmental or exploratory well that was deemed to be a dry well. As of December 31, 2018, there was one exploratory well drilled, but not yet completed. As of December 31, 2018, there were four development wells in the process of drilling and no wells in the process of completions. For the three years ended December 31, 2018, we drilled 138 gross (116 net) wells as operator with over a 96% success rate.

During the twelve months ended December 31, 2018, we successfully drilled 6 gross proved undeveloped wells and completed 6 gross proved undeveloped wells.

Productive Wells

The following table sets forth our total gross and net productive wells by oil or natural gas classification as of December 31, 2018.

	Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Operated (1)	256	213	345	296	601	509
Non-operated	109	15	374	73	483	88
Total	365	228	719	369	1,084	597

(1) Includes wells on which we act as contract operator.

Gross wells are the total number of producing wells in which we own an interest, and net wells are the sum of our fractional working interests owned in gross wells.

Acreage Data

The following table sets forth certain information regarding the developed and undeveloped acreage in which we have an interest as of December 31, 2018 for each of our producing areas. Acreage related to royalty, overriding royalty and

Table of Contents

other similar interests is excluded from this summary. As of December 31, 2018, approximately 94% of our leasehold acreage was held by existing production.

	Developed Acres		Undeveloped Acres		Total	
	Gross	Net	Gross	Net	Gross	Net
Western Anadarko	189,971	137,130	11,870	9,039	201,841	146,169
Eastern Anadarko	132,483	20,990	20,078	1,669	152,561	22,659
Other	19,287	16,925	—	—	19,287	16,925
All properties	341,741	175,045	31,948	10,708	373,689	185,753

Undeveloped Acreage Expirations

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2018 that will expire over the next three years by operating area unless production is established within the spacing units covering the acreage prior to the expiration dates or unless the existing leases are renewed prior to expiration.

	Expiring 2019		Expiring 2020		Expiring 2021	
	Gross	Net	Gross	Net	Gross	Net
Western Anadarko	5,605	5,393	4,376	3,117	1,889	530
Eastern Anadarko	14,497	748	5,419	799	162	121
All properties	20,102	6,141	9,795	3,916	2,051	651

A majority of the leases comprising the acreage set forth in the table above will expire at the end of their respective primary terms unless operations have commenced or production from the acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of operations or production in commercial quantities. We also have options to extend some of our leases through payment of additional lease bonus payments prior to the expiration of the primary term of the leases. In addition, we may attempt to secure a new lease upon the expiration of certain of our acreage; however, there may be third party leases that become effective immediately if our leases expire at the end of their respective terms and production has not been established prior to such date. We do not have any of our proved undeveloped reserves as of December 31, 2018 attributed to acreage whose lease expiration date precedes the scheduled initial drilling date. Our leases are mainly fee leases with primary terms of three to five years. We believe that our lease terms are similar to our competitors' fee lease terms as they relate to both primary term and royalty interests.

Competition

The oil and natural gas industry is highly competitive. We compete with numerous entities, including major domestic and foreign oil companies, other independent oil and natural gas concerns and individual producers and operators. Many of these competitors are large, well established companies and have financial and other resources substantially greater than ours. As a result, our competitors may be able to pay more for productive oil and natural gas properties and exploratory prospects, as well as evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional properties and to find and develop reserves will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Please read "Risk Factors—We may be unable to compete effectively with larger companies, which may adversely affect our ability to generate sufficient revenues."

We are also affected by competition for drilling rigs, equipment, services, supplies and qualified personnel. Starting with the downturn in commodity prices in late 2014, the United States onshore oil and natural gas industry experienced a surplus of drilling and completion rigs, equipment, pipe and personnel, due to significantly lower commodity prices. Although this provided a temporary respite from the previous high demand environment, demand for such services and equipment increased as commodity prices recovered. If commodity prices continue to increase and exploration and production activity increases, market forces may revert to the previous situation that resulted in delayed development drilling and other exploration activities and caused significant increases in the prices for this equipment and personnel. We are unable to predict when, or if, such changes may occur or how they would affect our development and exploitation programs.

Oil and Natural Gas Leases

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from any wells drilled on the leased premises. The lessor royalties and

Table of Contents

other leasehold burdens on our properties generally range from 17% to 25%. Our net revenue interests average 52% for our operated leases and 21% including all operated and non operated leases.

Approximately 94% of our leases (based on net acreage) are held by existing production and do not require lease rental payments.

Marketing and Major Customers

Our oil is generally sold under short term, extendable and cancellable agreements with unaffiliated purchasers based on published price bulletins reflecting an established field posting price. As a consequence, the prices we receive for oil and liquids move up and down in direct correlation with the oil market as it reacts to supply and demand factors. We do not own any oil or liquids pipelines or other assets for the transportation of those commodities, and transportation costs related to moving oil are deducted from the price received for oil. In September of 2014, we 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 our dedicated leases in Texas. 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. We have reserved capacity of up to 12,000 barrels per day on the system with the potential to increase throughput at a future date.

Our natural gas is sold under both long term and short term natural gas purchase agreements. Natural gas produced by us is sold at various delivery points at or near producing wells to natural gas gathering and marketing companies. We receive proceeds from prices that are based on various pipeline indices less any associated fees. On virtually all of our natural gas production, we are paid for the extracted NGLs based on a negotiated percentage of the proceeds that are generated from the customer's sale of the liquids, or based on other negotiated pricing arrangements. We do not own any natural gas pipelines or other assets for the transportation of natural gas.

During the year ended December 31, 2018, the largest purchasers of our production were Plains Marketing LP ("Plains Marketing"), ETC Field Services LLC and CVR Energy, Inc., which accounted for approximately 26%, 20% and 19% of consolidated oil and gas sales, respectively. If we were to lose any one of our customers, the loss could temporarily delay production and sale of our oil and natural gas in the related producing region. If we were to lose any single customer, we believe we could identify a substitute customer to purchase the impacted production volumes. However, if one or more of our larger customers ceased purchasing oil or natural gas altogether, the loss of such customer could have a detrimental effect on our production volumes in general and on our ability to find substitute customers to purchase our production volumes. For a discussion of the risks associated with the loss of key customers, please read "Risk factors—Our customer base is concentrated, and the loss of any one of our key customers could, therefore, adversely affect our financial condition and results of operations."

Seasonality

Generally, but not always, the demand for natural gas decreases during the summer months and increases during the winter months, resulting in seasonal fluctuations in the price we receive for our natural gas production. Seasonal anomalies such as mild winters sometimes lessen this fluctuation.

Title to Properties

Prior to completing an acquisition of producing oil and natural gas properties, we perform title reviews on significant leases, and depending on the materiality of properties, we may obtain a title opinion or review previously obtained title opinions. As a result, title examinations have been obtained on a significant portion of our properties.

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the titles to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to material defects. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property.

We conduct a portion of our operations through joint development agreements with third parties. Certain of our joint development agreements include complete to earn arrangements, whereby we are assigned title to properties from the third party after we complete wells. Occasionally, delivery of such assignments may be delayed. Furthermore, certain of

Table of Contents

our joint development agreements specify that assignments are only to occur when the wells are capable of producing hydrocarbons in paying quantities. These additional conditions to assignment of title may from time to time apply to wells of substantial value.

We believe that we have satisfactory title to all of our material assets. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens and encumbrances will materially detract from the value of these properties or from our interest in these properties or materially interfere with our use of these properties in the operation of our business. In addition, we believe that we have obtained sufficient rights of way grants and permits from public authorities and private parties for us to operate our business in all material respects as described in this Annual Report on Form 10 K.

Regulations

Our operations are substantially affected by federal, state and local laws and regulations. In particular, natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and limit the number of wells or locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress and federal agencies, the states, and the courts. We cannot predict when or whether any such proposals may become effective. Our competitors in the oil and natural gas industry are generally subject to the same regulatory requirements and restrictions that affect our operations.

Environmental Matters and Regulation

Our operations are subject to stringent and complex federal, state and local laws and regulations that govern the protection of the environment, as well as the discharge of materials into the environment. These laws and regulations may, among other things:

- require the acquisition of various permits before drilling commences;

- require the installation of pollution control equipment in connection with operations;
- restrict or prohibit our drilling and production activities during periods when such activities might affect protected wildlife;
- place restrictions or regulations upon the types, quantities or concentrations of materials or substances used in our operations;
- restrict the types, quantities or concentrations of various substances that can be released into the environment or used in connection with drilling, production and transportation activities;

Table of Contents

- limit or prohibit drilling activities on lands lying within wilderness, wetlands and other protected areas; and
- require remedial measures to mitigate pollution from former and ongoing operations, such as site restoration, pit closure and plugging of abandoned wells.

These laws and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, federal, state and local lawmakers and agencies frequently revise environmental laws and regulations. Such changes could affect costs for environmental compliance, such as waste handling and disposal, permitting, or cleanup for the oil and natural gas industry and could have a significant impact on our operating costs.

The following is a summary of some of the existing laws and regulations to which our business operations are subject.

Solid and Hazardous Waste Handling and Releases

The federal Resource Conservation and Recovery Act, or RCRA, and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non hazardous waste. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, production and transportation of oil and gas are currently excluded from regulation as hazardous wastes under RCRA. In the course of our operations, however, we generate some industrial wastes, such as paint wastes, waste solvents, and waste oils, which may be regulated as hazardous wastes. Although a substantial amount of the waste generated in our operations are regulated as non hazardous solid waste rather than hazardous waste, there is no guarantee that the U.S. Environmental Protection Agency, or the EPA, or individual states will not adopt more stringent requirements for the handling of non hazardous waste. Moreover, it is possible that certain oil and gas exploration and production wastes now classified as non hazardous could be classified as hazardous wastes in the future. Pursuant to a Consent Decree with environmental groups that filed suit in 2016, the EPA must review the exemption of oil and gas exploration and production wastes under RCRA by March 2019 and either determine revisions to the exemption are not necessary or undertake rulemaking to be completed by July 2021. Any repeal or modification of this or similar exemptions in comparable state statutes, would increase the volume of hazardous waste we are required to manage and dispose of, and would cause us, as well as our competitors, to incur increased operating expenses. Any such change could result in an increase in our costs to manage and dispose of waste, which could have a material adverse effect on our results of operations and financial position.

The Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, also known as "Superfund," and comparable state laws and regulations impose liability without regard to fault or legality of the original conduct, on certain classes of persons with respect to the release into the environment of substances designated under CERCLA as hazardous substances. These classes of persons, or so called potentially responsible parties, or PRPs, include current and past owners or operators of a site where the release occurred and anyone who disposed or arranged for the disposal of a hazardous substance released at a site. Under CERCLA, such persons may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to take actions in response to threats to public health or the environment and to seek to recover from the PRPs the costs of such action. Many states have adopted comparable or more stringent state statutes. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

Although CERCLA generally exempts "petroleum" from the definition of hazardous substance, in the course of our operations, we have generated and will generate wastes that may fall within CERCLA's definition of hazardous substances and may have disposed of these wastes at disposal sites owned and operated by others. We may also be the owner or operator of sites on which hazardous substances have been released. To our knowledge, neither we nor our predecessors have been designated as a PRP by the EPA under CERCLA; we also do not know of any prior owners or operators of our properties that are named as PRPs related to their ownership or operation of such properties. If contamination is discovered at a site on which we are or have been an owner or operator or to which we sent hazardous substances, we could be liable for the costs of investigation and remediation and natural resources damages.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production for many years. Although we believe we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on or under the properties owned, leased or operated by us, or on or under other locations, including offsite locations, where such substances have been taken for disposal. In addition, some of these properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or hydrocarbons were not under our control. These properties and the substances disposed or released on them may be subject to RCRA, CERCLA, and analogous state laws. Spills or other contamination required to be remediated have not required material capital expenditures to date. In the future, we could be required to remediate property, including groundwater, containing or impacted by previously disposed wastes (including wastes disposed or released by prior owners or operators, or property contamination, including groundwater contamination by prior owners or operators) or to perform remedial plugging operations to prevent future or mitigate existing contamination.

Clean Water Act

The federal Water Pollution Control Act, or the Clean Water Act, and analogous state laws impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of produced water and other oil and natural gas wastes, into waters of the United States or waters of the state, both broadly defined terms. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by a permit issued by the U.S. Army Corps of Engineers. Federal and state regulatory agencies can impose administrative, civil and criminal penalties, as well as require remedial or mitigation measures, for non compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations. In the event of an unauthorized discharge of pollutants, we may be liable for penalties and costs. The scope of the federal Clean Water Act is unsettled as it remains controverted in courts and is also the subject of proposed rulemaking. After a variety of agency and judicial actions, the rule adopted by the EPA and the U.S. Army Corps of Engineers in June 2015 to redefine the scope of federal Clean Water Act jurisdiction is currently in effect in 22 states, including Oklahoma, while the prior rule and scope is in effect in 28 states, including Texas; litigation regarding the validity of the 2015 rule remains pending. Further, in December 2018, the EPA and Corps proposed a new rule to further redefine the scope of federal Clean Water Act jurisdiction, which if finalized, would narrow such scope of federal jurisdiction compared to both the 2015 and prior rules; the final rule would likely be subject to litigation. With respect to wastewater disposal, the EPA finalized regulations in 2016 under the Clean Water Act setting a zero-discharge standard for wastewater discharges from hydraulic fracturing and other natural gas production activities to publicly owned treatment works.

Safe Drinking Water Act

The Safe Drinking Water Act, or SDWA, regulates, among other things, underground injection operations. Congress in the past has considered legislation that would impose additional regulation under the SDWA upon the use of hydraulic fracturing fluids. If similar legislation is enacted in the future, it could impose on our hydraulic fracturing operations permit and financial assurance requirements, requirements that we adhere to construction specifications, fulfill monitoring, reporting and recordkeeping obligations, and meet plugging and abandonment requirements. In addition to subjecting the injection of hydraulic fracturing to the SDWA regulatory and permitting requirements, the previously proposed legislation would have required the disclosure of the chemicals within the hydraulic fluids. In addition, the EPA has taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to the Underground Injection Control program in states in which the EPA is the permitting authority and released permitting guidance on the use of diesel fuel as an additive in hydraulic fracturing fluids. On December 13, 2016, the EPA released a study of the potential adverse effects that hydraulic fracturing may have on water quality and public health, concluding that there is scientific evidence that hydraulic fracturing activities can potentially impact drinking water resources in the United States under some circumstances. A committee of the U.S. House of Representatives conducted its own investigation into hydraulic fracturing practices. The U.S. Department of Energy also studied hydraulic fracturing and provided broad recommendations regarding best practices and other steps to enhance companies' safety and environmental performance of hydraulic fracturing. Legislation or other new requirements or restrictions regarding hydraulic fracturing could substantially increase compliance costs and the requirements could negatively impact our ability to conduct fracturing activities on our assets.

Other Regulation of Hydraulic Fracturing

On May 19, 2014, the EPA published an advance notice of rulemaking under the Toxic Substances Control Act, to gather information regarding the potential regulation of chemical substances and mixtures used in oil and gas exploration

Table of Contents

and production. Also, effective June 24, 2015, the Bureau of Land Management, or BLM, adopted rules regarding well stimulation, chemical disclosures, water management, and other requirements for hydraulic fracturing on federal and Indian lands; however these rules were rescinded by rule in December 2017. This rescission is being judicially challenged in federal court. BLM also adopted rules effective on January 17, 2017 to reduce venting, flaring, and leaks during oil and natural gas production activities on onshore federal and Indian leases. EPA delayed some of the requirements and September 2018 adopted a rule to rescind several requirements and revise others. A challenge to the September 2018 rule remains pending in federal court. Effective December 5, 2016, the U.S. National Park Service, or NPS, finalized updates to its regulations governing non federal oil and gas rights. This regulation remains listed for agency review for potential rescission or revision purusant to the Executive Order No. 13783 titled “Promoting Energy Independence and Economic Growth” dated March 28, 2017.

Hydraulic fracturing is also subject to regulation at the state and local levels. Several states have proposed or adopted legislative or administrative rules regulating hydraulic fracturing operations. For example, in 2011 the Railroad Commission of Texas adopted the Hydraulic Fracturing Chemical Disclosure Rule. The rule requires public disclosure of chemicals in fluids used in the hydraulic fracturing process for drilling permits issued after February 1, 2012. Other states that we operate in, including Oklahoma, have adopted similar chemical disclosure measures. Additionally, the Texas Commission on Environmental Quality has imposed more stringent emissions, monitoring, inspection, maintenance, and repair requirements on Barnett Shale operators to minimize Volatile Organic Compound, or VOC, releases.

Some states, including Oklahoma and Texas, also assert the authority to shut down injection wells or hydraulic fraturing operations that are deemed to contribute to induced seismicity, or seismic activity that is caused by human activity. The Oklahoma Corporation Commission (“OKCC”) adopted a plan calling for mandatory reductions in oil and gas wastewater disposal well volumes to address potential induced seismicity in Oklahoma, has been was implemented since 2015 by ongoing monitoring, reductions, or shut ins of disposal wells. In February 2017, the OKCC issued a directive aimed at limiting the growth in future underground injection disposal rates into the Arbuckle formation in an area with seismicity issues. The OKCC announced seismicity guidelines for hydraulic fracturing operations in the SCOOP and STACK plays in February 2018. Please see “Risk Factors—Federal and state legislative and regulatory initiatives relating to hydraulic fracturing and other oil and gas production activities as well as governmental reviews of such activities could result in increased costs, additional operating restrictions or delays, which could adversely affect our production” for a further discussion of state hydraulic fracturing regulation. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular.

Oil Pollution Act

The primary federal law related to oil spill liability is the Oil Pollution Act, or the OPA, which amends and augments oil spill provisions of the Clean Water Act and imposes certain duties and liabilities on certain “responsible parties” related to the prevention of oil spills and damages resulting from such spills in or threatening United States waters or adjoining shorelines. For example, operators of certain oil and gas facilities must develop, implement and maintain facility response plans, conduct annual spill training for certain employees and provide varying degrees of financial assurance. A liable “responsible party” includes the owner or operator of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge, or in the case of offshore facilities, the lessee or permittee of the area in which a discharging facility is located. OPA assigns strict joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist to the liability imposed by OPA, they are limited. In the event of an oil discharge or substantial threat of discharge, we may be liable for costs and damages.

Air Emissions

Our operations may be subject to the Clean Air Act, or CAA, and comparable state and local requirements for the control of emissions from sources of air pollution. Federal and state laws require new and modified sources of air pollutants to obtain permits prior to commencing construction. Major sources of air pollutants are subject to more stringent, federally imposed requirements including additional permits. Federal and state laws designed to control hazardous (toxic) air pollutants, might require installation of additional controls. Administrative enforcement actions for failure to comply strictly with air pollution regulations or permits are generally resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could bring lawsuits for civil penalties or injunctions or require us to forego construction, modification or operation of certain air emission sources.

Table of Contents

We may incur expenditures in the future for air pollution control equipment in connection with obtaining or maintaining operating permits and approvals for air emissions. For instance, effective October 15, 2012, final federal rules established new air emission controls for oil and natural gas production and natural gas processing operations, specifically addressing emissions of sulfur dioxide and volatile organic compounds, and hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The rules establish specific requirements regarding reduced emission completions, emissions from compressors, dehydrators, storage tanks and other production equipment in addition to leak detection requirements for natural gas processing plants. In October 2012, several challenges to the EPA's rules were filed by various parties, including environmental groups and industry associations. In a January 16, 2013 unopposed motion to hold this litigation in abeyance, the EPA indicated that it might reconsider some aspects of the rules. The case remains in abeyance. The EPA has since made several changes to the rules, including adopting amendments on March 12, 2018 to two narrow provisions for the collection of fugitive emission components at well sites and compressor stations. Further, on October 15, 2018, EPA proposed a rule to amend certain of these rules related to fugitive emissions requirements, well site pneumatic pump standards, the requirements for certification of closed vent systems by a professional engineer, and the alternative means of emissions limitations provisions. Depending on the outcome of judicial proceedings and regulatory actions, the rules may be further modified or rescinded or the EPA may issue new rules. These rules, as well as any modifications to these rules or additional rules, could require a number of modifications to our operations including the installation of new equipment. We have already reported some of our facilities as being subject to these rules and have incurred, and will continue to incur, costs to control emissions, and to satisfy reporting and other administrative requirements associated with these rules. Additionally, federal rules to regulate emissions of methane and volatile organic compounds from new and modified sources in the oil and gas sector and to establish the alternative criteria for aggregating multiple small surface sites into a single source for air quality permitting purposes became effective on August 2, 2016. This aggregation rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting processes and requirements across the oil and gas industry. Further, in 2015, the EPA adopted a lower national ambient air quality standard for ozone. This lower standard has caused additional areas to be designated as ozone nonattainment areas, causing states to revise their implementation plans to require additional emissions control equipment and to impose more stringent permit requirements on facilities in those areas; however, the areas in which we operate are not currently designated by EPA as nonattainment areas.

Endangered Species and Migratory Birds

The Endangered Species Act, or ESA, restricts activities that may affect endangered or threatened species or their habitats. Pursuant to the ESA, if a species is listed as threatened or endangered, activities adversely affecting that species or its habitat may be considered "take" and may incur liability. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. Criminal liability has been imposed in some jurisdictions for even an incidental taking of migratory birds, and the federal government recently issued indictments under the Migratory Bird Treaty Act to several oil and gas companies after dead migratory birds were found near reserve pits associated with drilling activities. However, on December 22, 2017, the U.S. Department of the Interior issued a new legal opinion that concludes that the Migratory Bird Treaty Act does not prohibit the accidental or "incidental" taking or killing of migratory birds.

We conduct operations in areas where certain species that are listed as threatened or endangered under the ESA may be present. On March 27, 2014, the U.S. Fish and Wildlife Service listed the Lesser Prairie Chicken as a threatened species under the Endangered Species Act. The designated habitat for the Lesser Prairie Chicken encompasses significant portions of our properties in the Anadarko Basin. On September 1, 2015 a federal district court in Texas vacated the listing of the Lesser Prairie Chicken as a threatened species, holding the Fish and Wildlife Service did not sufficiently account for voluntary range wide conservation efforts being implemented to protect the species. In July 2016, the Lesser Prairie Chicken was removed from the ESA List of Endangered and Threatened Wildlife following the court order. However, as of November 29, 2016, the Fish and Wildlife Service completed initial reviews of a petition filed by environmental groups to list the Lesser Prairie Chicken as endangered and found substantial information that the petitioned action may be warranted. An assessment of the biological status of the Lesser Prairie Chicken began in 2015 and further action remains pending.

In a special rule under ESA Section 4(d) released simultaneously with the decision to list the Lesser Prairie Chicken as threatened, the Fish and Wildlife Service exempted from "take" certain oil and gas and other activities conducted by a participant that could have resulted in an "incidental take" of the Lesser Prairie Chicken as long as the participant was enrolled in, and operating in compliance with, a range wide conservation plan endorsed by the Fish and Wildlife Service. The range wide conservation plan also included a Candidate Conservation Agreement with Assurances, or the CCAA, component that provides "take" coverage for properties enrolled into the CCAA before the listing was effective. Prior to

Table of Contents

the delisting, to mitigate the risk of liability from "incidental takes" of the Lesser Prairie Chicken, we enrolled affected leasehold interests in the CCAA. Given the delisted status of the Lesser Prairie Chicken and other considerations, Jones terminated its enrollment in the CCAA.   If the Lesser Prairie Chicken is listed as a threatened or endangered species, it could force us to incur additional costs and delay or otherwise limit or terminate our operations in the Anadarko Basin.

ESA issues remain dynamic. For example, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or limit future development activity in the affected areas. On August 23, 2016 an environmental group filed a Notice of Intent to sue the Fish and Wildlife Service for failure to act on 417 petitions to list species as threatened or endangered under the ESA.We continue to evaluate the impact of these rules, agency actions, and legal challenges on our operations. The listing under the Endangered Species Act of species in areas that we operate could force us to incur additional costs and delay or otherwise limit or terminate our operations.

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands may be subject to the National Environmental Policy Act, or NEPA, which requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an Environmental Assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed Environmental Impact Statement that may be made available for public review and comment. All of our current production activities, as well as any exploration and development plans that may be proposed in the future, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay or impose additional conditions upon the development of oil and natural gas projects.

Climate Change

More stringent laws and regulations relating to climate change and greenhouse gases, or GHGs, may be adopted in the future and could cause us to incur material expenses in complying with them. Both houses of Congress have in the past actively considered, but not passed, legislation to reduce emissions of GHGs. In the absence of comprehensive federal legislation on GHG emission control, the EPA is regulating GHGs as pollutants under the CAA. The EPA has adopted regulations affecting emissions of GHGs from motor vehicles and is also requiring permit review for GHGs from certain stationary sources that emit GHGs at levels above statutory and regulatory thresholds and are otherwise subject to CAA permitting requirements based on emissions of non GHG regulated air pollutants. We do not believe our operations are currently subject to these permitting requirements, but if our operations become subject to these or other similar requirements, we could incur significant costs to control our emissions and comply with regulatory requirements.

In addition, the EPA has adopted a mandatory GHG emissions reporting program that imposes reporting and monitoring requirements on various types of facilities and industries. In 2010, the EPA issued final rules to expand its existing GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage, and distribution facilities. The rule requires reporting of GHG emissions by regulated entities to the EPA on an annual basis. In 2015, the EPA added reporting of GHG emissions from gathering and boosting systems, completions and workovers of oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines to the GHG reporting rule. We are currently required to monitor and report GHG emissions under this rule, and operational and/or regulatory changes could increase the burden of compliance with GHG emissions monitoring and reporting requirements.

Because of the lack of any comprehensive legislative program addressing GHGs, there is continuing uncertainty regarding the further development of federal regulation of GHG emitting sources. Additionally, a number of states, either individually or as part of regional initiatives, have begun taking actions to control and/or reduce GHG emissions primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions to acquire and surrender emission allowances. The international, federal, regional and local regulatory initiatives that target GHGs also could adversely affect the marketability of the oil and natural gas we produce. For example, in 2015, the United States participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement entered into force November 4, 2016, and requires countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals, every five years beginning in 2020. The United States has expressed an intention to withdraw from participation in the Paris Agreement, but some state and local governments have expressed intentions to take GHG-related actions. In connection with the decision to adopt the Paris Agreement, the Intergovernmental Panel on Climate Change, or the IPCC, prepared a special report focused on the impacts of a specific increase in the average global temperature above pre-industrial levels and related GHG emission pathways, which was released on October 6, 2018, or the 2018 IPCC Report. The 2018 IPCC Report concludes that severe impacts of climate change could arise with a global warming of 1.5ºC above pre-industrial levels and that, if the increase continues at the current rate, global warming is likely to reach this temperature rise between 2030 and 2052. The report concludes that the measures set forth in the Paris Agreement are insufficient and that more aggressive targets and measures will be needed. Due to the uncertainties surrounding the regulation of and other risks associated with GHG emissions, we cannot predict the financial impact of related developments on our operations, however, we do not expect our operations to be affected any differently than other similarly situated domestic competitors.

The federal administration also issued a Climate Action Plan in June 2013. Among other things, the Climate Action Plan directs federal agencies to develop a strategy for the reduction of methane emissions, including emissions from the oil and natural gas industry. As previously mentioned, the EPA finalized a rule effective August 2016, setting standards for methane and volatile organic compound emissions from new and modified sources in the oil and gas sector. On November 10, 2016, the EPA issued a final Information Collection Request, or the ICR, that would have required numerous oil and gas companies to provide information regarding methane emissions from existing oil and gas facilities, but on March 2, 2017, EPA withdrew that ICR. The regulatory focus is shifting in the current administration, however, additional GHG regulation of the oil and gas industry remains a possibility. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations.

OSHA and Other Laws and Regulation

We are subject to the requirements of the federal Occupational Safety and Health Act, or OSHA, and comparable state statutes. These laws and regulations strictly govern the protection of the health and safety of employees. The OSHA hazard communication standard, the EPA community right to know regulations under Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that we are in substantial compliance with these applicable requirements and with other OSHA and comparable requirements.

We believe that we are in substantial compliance with all existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. We did not incur any material capital expenditures for remediation or pollution control activities for the years ended December 31, 2018, 2017 or 2016. Additionally, we are not aware of any environmental issues or claims that will require material capital expenditures during 2019 or that will otherwise have a material impact on our financial position or results of operations in the future. However, we cannot assure you that the passage of more stringent laws and regulations in the future will not have a negative impact on our business activities, financial condition or results of operations.

Offices

We currently lease approximately 43,000 square feet of office space in Austin, Texas at 807 Las Cimas Parkway, Austin, Texas 78746, where our principal offices are located. The primary lease expires in April 2020. We also lease approximately 5,000 square feet of office space in Oklahoma City, Oklahoma. Additionally, we lease field offices in Oklahoma City, Oklahoma and Canadian, Texas.

Employees

As of December 31, 2018, we had 83 employees, including 24 technical (geosciences, engineering, land), 33 field operations, 22 corporate (finance, accounting, business development, IT, human resources, office management) and 4 management. None of these employees are represented by labor unions or covered by any collective bargaining agreement. We consider our relations with our employees to be satisfactory. From time to time, we utilize the services of independent contractors to perform various field and other services as needed.

Available information

We are required to file annual, quarterly and current reports, proxy statements and other information with the SEC. Reports filed with the SEC are made available on its website at www.sec.gov.

Table of Contents

Our Class A common stock is traded on the OTCQX, which is the highest market tier operated by the OTC Markets Group, Inc., under the symbol "JONE." Our reports, proxy statements and other information are filed with the SEC. Through our website, www.jonesenergy.com, you can access, free of charge, electronic copies of all of the documents that we file with the SEC, including our annual reports on Form 10 K, quarterly reports on Form 10 Q and current reports on Form 8 K, as well as any amendments to these reports.

Item 1A. Risk Factors

Our business involves a high degree of risk. If any of the following risks, or any risks described elsewhere in this Annual Report on Form 10 K, were actually to occur, our business, financial condition or results of operations could be materially adversely affected and the trading price of our shares could decline resulting in the loss of part or all of your investment. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we currently consider immaterial may also adversely affect us.

Risks Relating to the Oil and Natural Gas Industry and Our Business:

Our indebtedness could adversely affect our financial condition. Our annual interest expense is large relative to our cash flow.

As of December 31, 2018, we had approximately $1.0 billion of total long-term debt obligations. Our indebtedness may significantly affect our financial flexibility in the future, including by making it more difficult for us to borrow in the future, making us more vulnerable to adverse economic or industry conditions and deterring third parties from material transactions with us. Our business may not continue to generate sufficient cash flow from operations to repay our indebtedness. If we are unable to generate sufficient cash flow from operations, we may be required to sell assets, to refinance all or a portion of our indebtedness or to obtain additional financing.

For more information on our indebtedness, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

We have concluded that we need to restructure our balance sheet to continue as a going concern, and we can provide no assurances of the terms of any such restructuring transaction in which we may engage or how any such transaction will impact our security-holders.

As a result of extremely challenging current market conditions and our significant indebtedness, we believe we will require a significant restructuring of our balance sheet within the next twelve months in order to continue as a going concern in the near term. We have based this belief on assumptions and estimates that may prove to be wrong, and we could spend our available financial resources less or more rapidly than currently expected. We have previously entered into confidentiality agreements and commenced discussions with legal and financial advisors for certain creditors to explore one or more possible restructuring, financing, refinancing, reorganization, recapitalization, amendment, waiver, forbearance, asset sale and/or similar transactions involving the Company. We have not yet reached agreement on mutually acceptable terms and conditions with our creditors regarding a possible transaction. Our current circumstances raise substantial doubt as to the ability of the company to continue to realize the carrying value of our assets and operate as a going concern.

There can be no assurance that our efforts will result in any agreement or what the terms of any agreement will be. If an agreement is reached and we pursue a restructuring, it may be necessary for us to file a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code in order to implement the agreement through the confirmation and consummation of a plan of reorganization approved by the bankruptcy court in the bankruptcy proceedings. We also may conclude that it is necessary to initiate Chapter 11 proceedings to implement a restructuring of our obligations even if we are unable to reach an agreement with our creditors and other relevant parties regarding the terms of such a restructuring. In either case, such a proceeding could be commenced in the near term. If a plan of reorganization is implemented in a bankruptcy proceeding, it is possible that holders of claims and interests with respect to, or rights to acquire, our equity securities would be entitled to little or no recovery, and those claims and interests may be canceled for little or no consideration. If that were to occur, we anticipate that all or substantially all of the value of all investments in our equity securities would be lost and that our equity holders would lose all or substantially all of their investment. It is also possible that our other stakeholders, including our secured and unsecured creditors, will receive substantially less than the amount of their claims.

Table of Contents

Our potential for restructuring transactions may impact our business, financial condition and operations.

Due to the potential for a restructuring of our balance sheet, there is risk that, among other things

- third parties lose confidence in our ability to continue to operate in the ordinary course, which could impact our ability to execute on our business strategy;
- it may become more difficult to attract, retain or replace key employees;
- employees could be distracted from performance of their duties;
- we could lose some or a significant portion of our liquidity, either due to stricter credit terms from vendors, or, in the event we undertake a Chapter 11 proceeding and conclude that we need to procure debtor-in-possession financing, an inability to obtain any needed debtor-in-possession financing or to provide adequate protection to certain secured lenders to permit us to access some or all of our cash; and
- our vendors, hedge counterparties, and service providers could seek to renegotiate the terms of our arrangements, terminate their relationship with us or require financial assurances from us.

We have significant capital needs, and our ability to access the capital and credit markets to raise capital on favorable terms is limited by our debt level and industry conditions.

Disruptions in the capital and credit markets, in particular with respect to the energy sector, could limit our ability to access these markets or may significantly increase our cost to borrow. Low commodity prices have caused and may continue to cause lenders to increase interest rates, enact tighter lending standards, refuse to refinance existing debt around maturity on favorable terms or at all and may reduce or cease to provide funding to borrowers. If we are unable to access the capital and credit markets on favorable terms, it could have a material adverse effect on our business, financial condition, results of operations, cash flows and liquidity and our ability to repay or refinance our debt.

A substantial or extended decline in oil, natural gas or NGL prices would adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil, natural gas and NGLs heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. During the past eight years, the NYMEX WTI oil price has ranged from a low of $26.19 per Bbl in February 2016 to a high of $113.39 per Bbl in April 2011, and was $56.92 as of February 20, 2019. The NYMEX Henry Hub spot market price of gas has ranged from a high of $8.15 per MMBtu in February 2014 to a low of $1.49 in March 2016, and was $2.64 as of February 20, 2019. These markets will likely continue to be volatile in the future, especially given the current geopolitical conditions. The prices we receive for our production and the levels of our production depend on numerous factors beyond our control. These factors include the following:

- regional and worldwide economic conditions impacting the supply and demand for oil, natural gas and NGLs;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC, including whether it meets the reduced output targets it has previously announced or may announce in the future;
- the level of production in non-OPEC countries;
- the price and quantity of imports of foreign oil, natural gas and NGLs;
- political conditions regionally, domestically or in other oil and gas producing regions;
- the level of domestic and global oil and natural gas exploration and production;
- the level of domestic and global oil and natural gas inventories;

Table of Contents

- localized supply and demand fundamentals and available pipeline and other oil and gas transportation capacity;
- weather conditions and natural disasters;
- domestic, local and foreign governmental regulations and taxes;
- activities by non-governmental organizations to restrict the exploration, development and production of oil and gas so as to reduce the potential for harm to the environment from such activities, including emissions of carbon dioxide, a greenhouse gas;
- speculation as to the future price of oil, natural gas and NGLs and the speculative trading of oil, natural gas and NGLs;
- trading prices of futures contracts;
- price and availability of competitors' supplies of oil, natural gas and NGLs;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- the impact of energy conservation efforts.

NGLs are made up of ethane, propane, isobutane, butane and natural gasoline, all of which have different uses and different pricing characteristics. NGLs comprised 30% of our 2018 production, and we realized an average price of $24.38 per barrel, a 15.6% increase from the average realized price of our 2017 production. An extended decline in NGL prices could materially and adversely affect our future business, financial condition and results of operations.

Substantially all of our production is sold to purchasers under contracts with market based prices. Lower oil, natural gas and NGL prices will reduce our cash flows and the present value of our reserves. Additionally, prices could reduce our cash flows to a level that would require us to borrow to fund our planned capital budget. Lower oil, natural gas and NGL prices may also reduce the amount of oil, natural gas and NGLs that we can develop and produce economically. Substantial decreases in oil, natural gas and NGL prices could render uneconomic a significant portion of our identified drilling locations. This may result in significant downward adjustments to our estimated proved reserves. As a result, a substantial or extended decline in oil, natural gas or NGL prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

Drilling for and producing oil, natural gas and NGLs are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future financial condition and results of operations will depend on the success of our exploration, exploitation, development and production activities. Our oil, natural gas and NGLs exploitation, development and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil and natural gas production. Our decisions to purchase, explore, develop or otherwise exploit locations or properties will depend in part on the evaluation of information obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospectus or producing fields will be applicable to our drilling prospects. In addition, our cost of drilling, completing and operating wells is often uncertain before drilling commences, which ultimately results in uncertainty as to when the capital investment required to deploy rigs will create an acceptable return for our shareholders. Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- delays imposed by or resulting from compliance with regulatory and contractual requirements and related lawsuits, which may include limitations on hydraulic fracturing or the discharge of greenhouse gases;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;

Table of Contents

- equipment failures or accidents;
- lack of available gathering facilities or delays in construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;
- fires and blowouts;
- adverse weather conditions, such as hurricanes, blizzards and ice storms;
- environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface or subsurface environment;
- declines in oil, natural gas and NGL prices;
- limited availability of financing at acceptable rates;
- title problems; and
- limitations in the market for oil, natural gas and NGLs.

Part of our strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations involve utilizing some of the latest drilling and completion techniques as developed by us and our service providers. Risks that we face while drilling include, but are not limited to, the following:

- effectively controlling the level of pressure flowing from particular wells;
- landing our wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running our casing the entire length of the wellbore; and
- running tools and other equipment consistently through the horizontal wellbore.

Risks that we face while completing our wells include, but are not limited to, the following:

- the ability to effectively fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

The results of our drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas have limited or no production history and, consequently, we are more limited in assessing future drilling results in these areas.

The value of our undeveloped acreage could decline if drilling results are unsuccessful.

The success of our horizontal drilling and completion techniques can only be evaluated over time as more wells are drilled and production profiles are established over a sufficiently long time period. If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, access to gathering systems, declines in oil, natural gas and NGL prices and/or other factors, the return on our investment in these areas may not be as attractive as we anticipate. Further, as a result of any of these developments we could incur material write downs of our oil and gas properties and the value of our undeveloped acreage could decline in the future.

Table of Contents

Our business requires substantial capital expenditures, and we may be unable to obtain needed capital or financing on satisfactory terms or at all.

Our exploration, exploitation, development and acquisition activities require substantial capital expenditures. Our 2018 capital expenditures totaled $192.6 million (excluding the impact of asset retirement costs, asset disposals and non-cash impairments of oil and gas properties), of which $149.5 million was utilized to drill and complete operated wells. The Company has established an initial capital budget of $60.0 million for 2019. Historically, we have funded development and operating activities primarily through a combination of equity capital raised from a private equity partner and public equity offerings, through borrowings under our senior secured revolving credit facility (the “Revolver”), through the issuance of debt securities and through internal operating cash flows. We intend to finance the majority of our capital expenditures predominantly with cash flows from operations. If necessary, we may also access capital through proceeds from potential asset dispositions, cash on hand, and the issuance of additional debt and equity securities. Our cash flow from operations and access to capital are subject to a number of variables, including:

- the estimated quantities of our oil, natural gas and NGL reserves;
- the amount of oil, natural gas and NGLs we produce from existing wells;
- the prices at which we sell our production;
- any gains or losses from our hedging activities;
- the costs of developing and producing our oil, natural gas and NGL reserves;
- take away capacity;
- our ability to acquire, locate and produce new reserves;
- the ability and willingness of banks and other lenders to lend to us; and
- our ability to access the equity and debt capital markets.

If our cash flow from operations is not sufficient to fund our capital expenditure budget, we may have limited ability to obtain the additional capital necessary to conduct our operations at expected levels. The indentures governing our senior notes due 2022, or the 2022 Notes, and senior notes due 2023, or the 2023 Notes, and the 2023 First Lien Notes restrict our ability to obtain new debt financing. We may not be able to obtain debt or equity financing on terms favorable to us, or at all. The failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a decline in our oil, natural gas and NGLs production or reserves, and in some areas a loss of properties.

External financing may be required in the future to fund our growth. We may not be able to obtain additional financing, and financing through the capital markets may not be available in the future. Without additional capital resources, we may be unable to pursue and consummate acquisition opportunities as they become available, and we may be forced to limit or defer our planned oil, natural gas and NGLs development program, which will adversely affect the recoverability and ultimate value of our oil, natural gas and NGLs properties, in turn negatively affecting our business, financial condition and results of operations.

Our transition to the OTCQX from the New York Stock Exchange (“NYSE”) may impact our trading volume and liquidity, lower prices of our Class A common stock and make more difficult for us to raise capital.

On November 26, 2018, the Company notified the NYSE of its intention to voluntarily delist its Class A common stock from the NYSE. Since November 27, 2018, our Class A common stock has been trading on the OTCQX under the symbol “JONE.” If an adequate trading market for our Class A common stock does not develop on the OTCQX, it could negatively impact us by (i) reducing the liquidity and market price of our Class A common stock; (ii) reducing the number of investors willing to hold or acquire our Class A common stock, which could negatively impact our ability to raise equity financing; (iii) limiting our ability to use a registration statement to offer and sell freely tradeable securities, thereby preventing us from accessing the public capital markets; and (iv) impairing our ability to provide equity incentives to our employees.

Table of Contents

The development of our proved undeveloped reserves in our areas of operation may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our undeveloped reserves may not be ultimately developed or produced by us. In addition, there are no assurances that our proved undeveloped reserves will be converted into producing reserves by us.

Approximately 10% of our total estimated proved reserves were classified as proved undeveloped as of December 31, 2018. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. In addition, declines in commodity prices could cause us to reevaluate our development plans and delay or cancel development. Delays in the development of our reserves, increases in costs to drill and develop such reserves or sustained periods of low commodity prices will reduce the future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves or lower commodity prices could cause us to have to reclassify our proved reserves as unproved reserves. There is no certainty that we will be able to convert unproved reserves to developed reserves.

Our identified drilling locations are scheduled to be drilled over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling, which in certain instances could prevent or delay associated expected production. In addition, we may not be able to raise the amount of capital that would be necessary to drill a substantial portion of our identified drilling locations.

Our management team has identified and scheduled certain drilling locations as an estimation of our future multi year drilling activities on our existing acreage. These drilling locations represent a significant part of our growth strategy. Our drilling locations are in various stages of evaluation, ranging from a location that is ready to drill to a location that will require substantial additional interpretation. There is no way to predict in advance of drilling and testing whether any particular location will yield oil, natural gas or NGLs in sufficient quantities to recover drilling or completion costs or to be economically viable. Similarly, the use of technologies and the study of producing fields in the same area of producing wells will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. Even if sufficient quantities of oil or natural gas exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production or abandonment of the well. If we drill additional wells that we identify as dry holes in our current and future drilling locations, our drilling success rate may decline and materially harm our business. In addition, our ability to drill and develop these drilling locations depends on a number of uncertainties, including oil, natural gas and NGL prices, the availability and cost of capital, drilling and production costs, the availability of drilling services and equipment, drilling results, lease expirations, gathering systems, marketing and pipeline transportation constraints, regulatory approvals and other factors. Because of the uncertainty inherent in these factors, we do not know if the numerous drilling locations we have identified will ever be drilled or if we will be able to produce oil, natural gas or NGLs from these or any other drilling locations.

Our liquidity position has resulted in impairment of certain of our properties. Future declines in commodity prices, increases in operating costs or adverse changes in well performance may result in additional write-downs of the carrying amounts of our assets, which could materially and adversely affect our results of operations in future periods.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on prevailing commodity prices and specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our properties. A write down constitutes a non cash charge to earnings. Such impairment may be accompanied by a reduction in proved reserves, thereby increasing future depletion charges per unit of production.

Primarily due to our liquidity position, we recorded non-cash, pre-tax impairment charges of $261.0 million and $1,060.0 million to our proved oil and gas properties in the Eastern Anadarko Basin and Western Anadarko Basin, respectively and a non-cash, pre-tax impairment charge of $11.0 million to our unproved oil and gas properties in the Western Anadarko Basin. Future declines in natural gas, NGLs or oil prices, increases in operating costs or adverse changes in well performance, among other things, may result in our having to make significant additional future downward adjustments to our estimated proved reserves and/or could result in additional non-cash impairment charges to write-down the carrying amount of our assets, which may have a material adverse effect on our results of operations in future periods. Any impairment of our assets would require us to take an immediate charge to earnings. Such charges could be material to our results of operations and could adversely impact our financial condition and results of operations. See “Impairment of Oil and Gas Properties” in “Management’s Discussion and Analysis of Financial Condition and Results of Operations.”

Our use of 2D and 3D seismic data is subject to interpretation and may not accurately identify the presence of drilling hazards, including faults, or hydrocarbons, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 2D and 3D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons or drilling hazards such as faults are, in fact, present in those structures. In addition, the use of 3D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur greater drilling and testing expenses as a result of such expenditures, which may result in a reduction in our returns or losses. As a result, our drilling activities may not be successful or economical, and our overall drilling success rate or our drilling success rate for activities in a particular area could decline.

We often gather 3D seismic data over large areas. Our interpretation of seismic data delineates those portions of an area that we believe are desirable for drilling. Therefore, we may choose not to acquire option or lease rights prior to acquiring seismic data, and, in many cases, we may identify hydrocarbon indicators before seeking option or lease rights in the location. Conversely, we may incur substantial expenditures to acquire and analyze 3D seismic data but not be able to lease attractive locations on acceptable terms.

Our hedging strategy may be ineffective in reducing the impact of commodity price volatility from our cash flows or may limit our ability to realize cash flows from commodity price increases, which could result in financial losses or could reduce our income.

To achieve more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of oil, natural gas and NGLs, we have historically entered into commodity derivative contracts for a significant portion of our oil, natural gas and NGL production that could result in both realized and unrealized hedging losses. The extent of our commodity price exposure is related largely to the effectiveness and scope of our commodity derivative contracts. For example, some of the commodity derivative contracts we utilize are based on quoted market prices, which may differ significantly from the actual prices we realize in our operations for oil, natural gas and NGLs. For the years ending December 31, 2019, 2020, and 2021, approximately 38%, 67%, and 100%, respectively, of our estimated total oil, natural gas and NGL production from proved reserves, based on our reserve report as of December 31, 2018, will not be covered by commodity derivative contracts.

Our policy has been to hedge a significant portion of our estimated oil, natural gas and NGLs production. However, our price hedging strategy and future hedging transactions will be determined at our discretion. We are not under an obligation to hedge a specific portion of our production. The prices at which we hedge our production in the future will be dependent upon commodity prices at the time we enter into these transactions, which may be substantially higher or lower than current oil, natural gas and NGLs prices. Accordingly, our price hedging strategy may not protect us from significant declines in oil, natural gas and NGL prices received for our future production. Conversely, our hedging strategy may limit our ability to realize cash flows from commodity price increases. For example, the estimated mark-to-market value of our commodity price hedges in 2019 and beyond represents a liability of $8.2 million, incorporating strip pricing as of February 20, 2019 but excluding adjustments for credit risk.

In addition, our actual future production may be significantly higher or lower than we estimate at the time we enter into commodity derivative contracts for such period. If the actual amount is higher than we estimate, we will have greater commodity price exposure than we projected. If the actual amount is lower than the notional amount of our commodity derivative contracts, we might be forced to satisfy all or a portion of our commodity derivative contracts without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, substantially diminishing our liquidity. There may be a change in the expected differential between the underlying commodity price in the commodity derivative contract and the actual price received, which may result in payments to our derivative counterparty that are not offset by our receipt of payments for our production in the field.

As a result of these factors, our commodity derivative activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows.

Table of Contents

Our hedging transactions expose us to counterparty credit risk.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden changes in a counterparty's liquidity, which could impair their ability to perform under the terms of the derivative contract. We are unable to predict sudden changes in a counterparty's creditworthiness or ability to perform. Even if we do accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions. Currently our entire hedge portfolio is hedged directly with banks in our credit agreements, thus allowing hedging without any margin requirements.

During periods of falling commodity prices, our hedge receivable positions generally increase, which increases our counterparty credit exposure. If the creditworthiness of our counterparties deteriorates and results in their nonperformance, we could incur a significant loss.

Derivatives legislation and implementing rules could have an adverse effect on our ability to use derivatives to reduce the effect of commodity price risk, interest rate risk and other risks associated with our business.

We use commodity derivatives to manage our commodity price risk. The U.S. Congress adopted comprehensive financial reform legislation that, among other things, expands comprehensive federal oversight and regulation of derivatives and many of the entities that participate in that market. Although the Dodd Frank Wall Street Reform and Consumer Protection Act, or the Dodd Frank Act, was enacted on July 21, 2010, the Commodity Futures Trading Commission, or the CFTC, and the SEC, along with certain other regulators, must promulgate final rules and regulations to implement many of its provisions relating to derivatives. While some of these rules have been finalized, some have not. When fully implemented, the law and any new regulations could increase the operational and transactional cost of derivatives contracts and affect the number and/or creditworthiness of available counterparties.

In addition, we may transact with counterparties based in the European Union, Canada or other jurisdictions which, like the U.S., are in the process of implementing regulations to regulate derivatives transactions, some of which are currently in effect and impose operational and transactional costs on our derivatives activities.

Unless we replace our reserves, our reserves and production will naturally decline, which would adversely affect our business, financial condition and results of operations.

Unless we conduct successful exploration, development and acquisition activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil, natural gas and NGL reserves and production, and therefore our cash flows and income, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations will be adversely affected.

If we do not fulfill our obligation to drill minimum numbers of wells specified in our joint development agreements, we will lose the right to develop the undeveloped acreage associated with the agreement and any proved undeveloped reserves attributable to such undeveloped acreage.

If we do not meet our obligation to drill the minimum number of wells specified in a joint development agreement, we will lose the right to continue to develop the undeveloped acreage covered by the agreement, which would result in the loss of any proved undeveloped reserves attributable to such undeveloped acreage.

Our estimated oil, natural gas and NGLs reserve quantities and future production rates are based on many assumptions that may prove to be inaccurate. Any significant inaccuracies in these reserve estimates or the underlying assumptions will materially affect the quantities and present value of our reserves.

Numerous uncertainties are inherent in estimating quantities of oil, natural gas and NGL reserves. Our estimates of our proved reserve quantities are based upon our reserve report as of December 31, 2018. Reserve estimation is a subjective process of evaluating underground accumulations of oil, natural gas and NGLs that cannot be measured in an exact manner. Reserves that are “proved reserves” are those estimated quantities of oil, natural gas and NGLs that geological and engineering data demonstrate with reasonable certainty are recoverable in future years from known reservoirs under

Table of Contents

existing economic and operating conditions and that relate to projects for which the extraction of hydrocarbons must have commenced or the operator must be reasonably certain will commence within a reasonable time.

The process of estimating oil, natural gas and NGL reserves is complex, requiring significant decisions and assumptions in the evaluation of available geological, engineering and economic data for each reservoir, and these reports rely upon various assumptions, including assumptions regarding future oil, natural gas and NGL prices, production levels, and operating and development costs. As a result, estimated quantities of proved reserves and projections of future production rates and the timing of development expenditures may prove to be inaccurate. Quantities of proved reserves are estimated based on pricing conditions in existence during the period of assessment and costs at the end of the period of assessment. Changes to oil, natural gas and NGL prices in the markets for such commodities may have the impact of shortening the economic lives of certain fields, because it becomes uneconomic to produce all recoverable reserves on such fields, which reduces proved property reserve estimates.

Over time, we may make material changes to reserve estimates taking into account the results of actual drilling and production. Any significant variance in our assumptions and actual results could greatly affect our estimates of reserves, the economically recoverable quantities of oil, natural gas and NGLs attributable to any particular group of properties, the classifications of reserves based on risk of recovery, and estimates of the future net cash flows. In addition, changes in future production cost assumptions could have a significant effect on our proved reserve quantities.

The standardized measure of discounted future net cash flows from our proved reserves will not necessarily be the same as the current market value of our estimated oil, natural gas and NGL reserves.

You should not assume that the standardized measure of discounted future net cash flows from our proved reserves is the current market value of our estimated oil, natural gas and NGL reserves. In accordance with SEC requirements, we based the discounted future net cash flows from our proved reserves on the 12 month unweighted arithmetic average of the first day of the month commodities prices for the preceding 12 months without giving effect to derivative transactions. Actual future net cash flows from our oil and natural gas properties will be affected by factors such as:

- commodity price hedging and actual prices we receive for oil, natural gas and NGLs;
- actual cost of development and production expenditures;
- the amount and timing of actual development and production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating standardized measure may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our company or the oil and natural gas industry in general.

If oil prices decline by $10.00 per Bbl, then our standardized measure as of December 31, 2018 excluding hedging impacts would decrease approximately $93.7 million holding all costs constant. If natural gas prices decline by $1.00 per Mcf, then our standardized measure as of December 31, 2018 excluding hedging impacts would decrease by approximately $71.7 million holding all costs constant.

Over 66% of our estimated proved reserves are located in the Western Anadarko Basin in the Texas Panhandle and Oklahoma; however, our 2019 drilling plan is primarily focused on the development of our assets in the Merge play located in the Eastern Anadarko Basin in Oklahoma. Drilling, exploring for and producing, oil, natural gas and NGLs in a different play than the location of our historical operations subjects us to uncertainties that could adversely affect our business, financial condition or results of operations.

Over 66% of our estimated proved reserves as of December 31, 2018 were located in the Western Anadarko Basin in the Texas Panhandle and Oklahoma, and approximately 58% of our 2018 production was from the Cleveland formation where properties are located in four contiguous counties of Texas and Oklahoma. In 2019, we plan to target the liquids rich Woodford shale and Meramec formations with our rig program in the Merge. As a result of this change in the area of our significant operations, we may be exposed to the impact of different supply and demand factors, regulations, processing or transportation capacity constraints, availability of equipment, facilities, personnel or services market limitations than we have been exposed to previously in our historical operations in the Western Anadarko Basin. These uncertainties and others inherent in allocating our capital resources to operations in a new geographic area could have a material adverse effect on our financial condition and results of operations.

Our customer base is concentrated, and the loss of any one of our key customers could, therefore, adversely affect our financial condition and results of operations.

Historically, we have been dependent on a few customers for a significant portion of our revenue. For the year ended December 31, 2018 purchases by our top five customers accounted for approximately 26%, 20%, 19%, 12% and 6%, respectively, of our total oil, natural gas and NGL sales. This concentration of customers may increase our overall exposure to credit risk, and customers will likely be similarly affected by changes in economic and industry conditions. To the extent that any of our major purchasers reduces their purchases of oil, natural gas or NGLs or defaults on their obligations to us, our financial condition and results of operations could be adversely affected.

We may be unable to make attractive acquisitions or successfully integrate acquired businesses, and any inability to do so may disrupt our business and hinder our ability to grow.

In the future we may make acquisitions of businesses that complement or expand our current business. We may not be able to identify attractive acquisition opportunities, particularly in light of our low liquidity levels. In addition, increased competition in the areas in which we operate, including the Merge play, may make it more difficult for us to identify or complete acquisitions. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

Any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about estimated proved reserves, future production, commodity prices, revenues, capital expenditures, operating expenses and costs;
- an inability to successfully integrate the assets we acquire;
- an inability to obtain satisfactory title to the assets we acquire;
- a decrease in our liquidity by using a significant portion of our available cash or borrowing capacity to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur additional debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs for which we obtain no or limited indemnity or other recourse;
- the diversion of management’s attention from other business concerns;
- an inability to hire, train or retain qualified personnel to manage and operate our growing assets; and
- the occurrence of other significant changes, such as impairment of oil and natural gas properties, goodwill or other intangible assets, asset devaluation or restructuring charges.

Our decision to acquire a property will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic data and other information, the results of which are often inconclusive and subject to various interpretations.

The success of any completed acquisition will depend on our ability to integrate effectively the acquired assets into our existing operations. The process of integrating acquired assets may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, even if we successfully integrate an acquisition, it may not be possible to realize the full benefits we may expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame. Anticipated benefits of an acquisition may be offset by operating losses relating to changes in commodity prices in oil and natural gas industry conditions, risks and uncertainties relating to the exploratory

Table of Contents

prospects of the combined assets or operations, or an increase in operating or other costs or other difficulties. If we fail to realize the benefits we anticipate from an acquisition, our results of operations may be adversely affected.

Deficiencies of title to our leased interests could significantly affect our financial condition.

It is our practice, in acquiring oil and natural gas leases or undivided interests in oil and natural gas leases or other developed rights, not to incur the expense of retaining lawyers to examine the title to the mineral interest to be acquired. Rather, we rely upon the judgment of oil and natural gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental or county clerk's office to determine mineral ownership before we acquire an oil and gas lease or other developed rights in a specific mineral interest.

Prior to the drilling of an oil or gas well, it is the normal practice in our industry for the operator of the well to obtain a drilling title opinion from a qualified title attorney to ensure there are no obvious title defects on the property on which the well is to be located. The title attorney would typically research documents that are of record, including liens, taxes and all applicable contracts that burden the property. Frequently, as a result of such examinations, certain curative work must be undertaken to correct defects in the marketability of the title, and such curative work entails expense. Our failure to completely cure any title defects may invalidate our title to the subject property and adversely impact our ability in the future to increase production and reserves. Additionally, because a less strenuous title review is conducted on lands where a well has not yet been scheduled, undeveloped acreage has greater risk of title defects than developed acreage. Any title defects or defects in assignment of leasehold rights in properties in which we hold an interest may adversely impact our ability in the future to increase production and reserves, which could have a material adverse effect on our business, financial condition and results of operations.

We conduct a substantial portion of our operations through joint development agreements with third parties. Certain of our joint development agreements include complete to earn arrangements, whereby we are assigned title to properties from the third party after we complete wells and, in the case of certain counterparties, after completion reports relating to the wells have been approved by regulatory authorities whose approval may be delayed. Furthermore, certain of our joint development agreements specify that assignments are only to occur when the wells are capable of producing hydrocarbons in paying quantities. These additional conditions to assignment of title may from time to time apply to wells of substantial value. If one of our counterparties assigned title to a well in which we had earned an interest (according to our joint development agreement) to a third party, our title to such a well could be adversely impacted. In addition, if one of our counterparties becomes a debtor in a bankruptcy proceeding, or is placed into receivership, or enters into an assignment for the benefit of creditors, after we had earned ownership of, but before we had received title to, a well, certain creditors of the counterparty may have rights in that well that would rank prior to ours.

Recently enacted tax legislation may impact our ability to fully utilize our interest expense deductions and net operating loss carryovers to fully offset our taxable income in future periods.

Recently enacted legislation commonly known as the Tax Cuts and Jobs Act includes provisions that generally will (i) limit our annual deductions for interest expense to no more than 30% of our "adjusted taxable income" (plus 100% of our business interest income) for the year and (ii) permit us to offset only 80% (rather than 100%) of our taxable income with net operating losses we generated after 2017. Interest expense and net operating losses subject to these limitations may be carried forward by us for use in later years, subject to these limitations. Additionally, the Tax Cuts and Jobs Act repealed the domestic manufacturing tax deduction for oil and gas companies. These tax law changes could have the effect of causing us to incur income tax liability and/or obligations under our Tax Receivable Agreement (the "Tax Receivable Agreement") sooner than we otherwise would have incurred such liability or, in certain cases, could cause us to incur income tax liability that we might otherwise not have incurred, in the absence of these tax law changes. The Tax Cuts and Jobs Act also includes provisions that reduce the maximum federal corporate income tax rate from 35% to 21% and eliminate the alternative minimum tax, which would lessen any adverse impact of the limitations described in the preceding sentences.

Certain federal income tax deductions currently available with respect to oil and natural gas exploration and development may be eliminated and new taxes may be imposed as a result of future legislation.

From time to time, legislation is introduced that would, if enacted, make significant changes to U.S. tax laws. These proposed changes have included repealing many tax incentives and deductions that are currently used by U.S. oil and gas companies and imposing new fees. Among others, proposed changes have included: elimination of the ability to fully deduct intangible drilling costs in the year incurred; repeal of the percentage depletion deduction for oil and gas

Table of Contents

properties; repeal of the domestic manufacturing tax deduction for oil and gas companies; increase in the geological and geophysical cost amortization period for independent producers; imposing a per barrel fee on domestically produced oil; and implementation of a fee on non producing federal oil and gas leases. The recently enacted Tax Cuts and Jobs Act did not include any of these proposals, except for the repeal of the domestic manufacturing tax deduction for oil and gas companies. However, it is possible that such provisions could be proposed in the future. The passage of legislation containing some or all of these provisions or any other similar change in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available to us with respect to oil and natural gas exploration and development, and any such change could have a material adverse effect on our business, financial condition and results of operations.

We may be unable to compete effectively with larger companies, which may adversely affect our ability to generate sufficient revenues.

The oil and natural gas industry is intensely competitive, and we compete with other companies that have more resources than us. Many of our larger competitors not only drill for and produce oil and natural gas, but also engage in refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may have a greater ability to continue drilling activities during periods of low oil, natural gas and NGL prices, to contract for drilling equipment, to secure trained personnel, and to absorb the burden of present and future federal, state, local and other laws and regulations. The oil and natural gas industry has periodically experienced shortages of drilling rigs, equipment, pipe and personnel, which has delayed development drilling and other exploitation activities and has caused significant price increases. Competition for hiring experienced personnel, particularly in the engineering and technical, accounting and financial reporting, tax and land departments continues to be strong. In addition, competition for attractive oil and natural gas producing properties, oil and natural gas companies, and undeveloped leases and drilling rights remains robust. Any inability to compete effectively with larger companies could have a material adverse impact on our financial condition and results of operations.

The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services using new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage or competitive pressures may force us to implement those new technologies at substantial costs. In addition, other oil and natural gas companies may have greater financial, technical, and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures and implement new technologies on a timely basis or at an acceptable cost. If one or more of the technologies we use now or in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, our business, financial condition and results of operations could be materially adversely affected.

We participate in oil and gas leases with third parties who may not be able to fulfill their commitments to our projects.

We frequently own less than 100% of the working interest in the oil and gas leases on which we conduct operations, and other parties will own the remaining portion of the working interest. Financial risks are inherent in any operation where the cost of drilling, equipping, completing and operating wells is shared by more than one person. We could be held liable for joint activity obligations of other working interest owners, such as nonpayment of costs and liabilities arising from the actions of other working interest owners. In addition, declines in oil, natural gas and NGL prices may increase the likelihood that some of these working interest owners, particularly those that are smaller and less established, are not able to fulfill their joint activity obligations. A partner may be unable or unwilling to pay its share of project costs, and, in some cases, a partner may declare bankruptcy. In the event any of our project partners do not pay their share of such costs, we would likely have to pay those costs, and we may be unsuccessful in any efforts to recover these costs from our partners, which could materially adversely affect our financial position.

The unavailability or high cost of drilling rigs, equipment, supplies, personnel and oil field services as well as fees for the cancellation of such services could adversely affect our ability to execute development and exploitation plans on a timely basis and within budget, and consequently could adversely affect our anticipated cash flow.

We utilize third party services to maximize the efficiency of our operation. The cost of oil field services typically fluctuates based on demand for those services. We may not be able to contract for such services on a timely basis, or the cost of such services may not remain at a satisfactory or affordable level. Shortages or the high cost of drilling rigs, equipment, supplies or personnel, including hydraulic fracturing equipment, supplies and personnel necessary for horizontal drilling, could delay or adversely affect our development and exploitation operations, which could have a material adverse effect on our financial condition and results of operations.

Our business depends in part on pipelines, transportation and gathering systems and processing facilities owned by others. Any limitation in the availability of those facilities could interfere with our ability to market our oil, natural gas and NGLs production and could harm our business.

The marketability of our oil, natural gas and NGLs production depends in part on the availability, proximity and capacity of pipelines and other transportation methods, such as trucks, gathering systems and processing facilities owned by third parties. The amount of oil, natural gas and NGLs that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage or lack of contracted capacity on such systems. Also, the transfer of our oil, natural gas and NGLs on third party pipelines may be curtailed or delayed if it does not meet the quality specifications of the pipeline owners. Our access to transportation options, including trucks owned by third parties, can also be affected by U.S. federal and state regulation of oil and gas production and transportation, general economic conditions and changes in supply and demand. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we are provided only with limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering system or transportation or processing facility capacity could reduce our ability to market our oil, natural gas and NGLs production and harm our business.

We could experience periods of higher costs if commodity prices continue to rise. These increases could reduce our profitability, cash flow and ability to complete development activities as planned.

Historically, our capital and operating costs have risen during periods of increasing oil, natural gas and NGL prices. These cost increases result from a variety of factors beyond our control, such as increases in the cost of electricity, steel and other raw materials that we and our vendors rely upon; increased demand for labor, services and materials as drilling activity increases; and increased taxes. Decreased levels of drilling activity in the oil and natural gas industry in recent periods have led to declining costs of some drilling equipment, materials and supplies. However, with the recent increase in commodity prices, such costs may rise faster than increases in our revenue, thereby negatively impacting the profitability of our wells. This impact may be magnified to the extent that our ability to participate in the commodity price increases is limited by our derivative activities.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. Our oil and natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater contamination;
- adverse weather conditions and natural disasters;
- encountering abnormally pressured formations;
- facility or equipment malfunctions;

- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- personal injuries and death; and
- terrorist attacks targeting oil and natural gas related facilities and infrastructure.

Table of Contents

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage and associated clean up responsibilities;
- regulatory investigations, penalties or other sanctions;
- suspension of our operations; and
- repair and remediation costs.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

Our oil and natural gas exploration and production operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. Failure or delay in obtaining regulatory approvals or drilling permits could have a material adverse effect on our ability to develop our properties, and receipt of drilling permits with onerous conditions could increase our compliance costs. In addition, regulations regarding conservation practices and the protection of correlative rights affect our operations by limiting the quantity of oil, natural gas and NGLs we may produce and sell.

We are subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration, production and transportation of oil, natural gas and NGLs, as well as safety matters. Legal requirements are frequently changed and subject to interpretation, and we are unable to predict the ultimate cost of compliance with these requirements or their ultimate effect on our operations. We may be required to make significant expenditures to comply with governmental laws and regulations. The discharge of oil, natural gas, NGLs or other pollutants into the air, soil or water may give rise to significant liabilities on our part to the government, and third parties and may require us to incur substantial costs for remediation.

See “Item 1. Business—Regulations” for a further description of the laws and regulations that affect us.

Our ability to pursue our business strategies may be adversely affected if we incur costs and liabilities due to a failure to comply with environmental regulations or a release of hazardous substances into the environment.

We may incur significant costs and liabilities as a result of environmental requirements applicable to the operation of our wells, gathering systems and other facilities. These costs and liabilities could arise under a wide range of federal, state and local environmental laws and regulations, including, for example:

- the Clean Air Act, or CAA, and comparable state laws and regulations that impose obligations related to air emissions;
- the Clean Water Act and Oil Pollution Act, or OPA, and comparable state laws and regulations that impose obligations related to discharges of pollutants into regulated bodies of water;
- the Resource Conservation and Recovery Act, or RCRA, and comparable state laws that impose requirements for the handling and disposal of waste from our facilities;
- the Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or at locations to which we have sent waste for disposal;

Table of Contents

- the Environmental Protection Agency's, or the EPA's, community right to know regulations under the Title III of CERCLA and comparable state laws that require that we organize and/or disclose information about hazardous materials used or produced in our operations;
- the Occupational Safety and Health Act, or OSHA, which establishes workplace standards for the protection of the health and safety of employees, including the implementation of hazard communications programs designed to inform employees about hazardous substances in the workplace, potential harmful effects of these substances, and appropriate control measures;
- the National Environmental Policy Act, or NEPA, which requires federal agencies to evaluate major agency actions having the potential to significantly impact the environment and which may require the preparation of Environmental Assessments and more detailed Environmental Impact Statements that may be made available for public review and comment;
- the Migratory Bird Treaty Act, which implements various treaties and conventions between the United States and certain other nations for the protection of migratory birds and, pursuant to which the taking, killing, or possessing of migratory birds is unlawful without a permit, thereby potentially requiring the implementation of operating restrictions or a temporary, seasonal, or permanent ban on operations in affected areas; and
- the Endangered Species Act, or ESA, and analogous state laws, which seek to ensure that activities do not jeopardize endangered or threatened animals, fish and plant species, nor destroy or modify the critical habitat of such species. In particular, if the Lesser Prarie Chicken is listed as threatened or endangered under the ESA, it could force us to incur additional costs and delay or otherwise limit or terminate our operations in significant portions of the Anadarko Basin.

We may incur significant delays, costs and liabilities as a result of federal, state and local environmental, health and safety requirements applicable to exploration, development and production activities. These laws and regulations may require us to obtain a variety of permits or other authorizations governing our air emissions, water discharges, waste disposal, development in regulated wetlands or waters, or other environmental impacts associated with drilling, production and product transportation pipelines or other operations; regulate the sourcing and disposal of water used in the drilling, fracturing and completion processes; limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, frontier and other protected areas or that contain regulated wetlands or other waters; require remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits; and/or impose substantial liabilities for spills, pollution or failure to comply with regulatory filing requirements. In addition, these laws and regulations are complex, change frequently and have tended to become increasingly stringent over time; however, future changes to environmental laws and regulations remain uncertain. Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures, including the assessment of monetary penalties, the imposition of remedial requirements, and the issuance of orders enjoining future operations. Certain environmental statutes, including the RCRA, CERCLA, the federal OPA and analogous state laws and regulations, impose strict joint and several liability for costs required to clean up and restore sites where petroleum or hazardous substances or other waste products have been disposed of or otherwise released. More stringent laws and regulations, including laws related to climate change and greenhouse gases or induced seismicity, may be adopted in the future. If there are more expensive and stringent environmental legislation and regulations applied to the oil and natural gas industry, it could result in increased costs of doing business and consequently affect profitability. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances or other waste products into the environment. We are also subject to many other environmental requirements delineated in "Business—Environmental Matters and Regulation."

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing and other oil and gas production activities as well as governmental reviews of such activities could result in increased costs, additional operating restrictions or delays, which could adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. We routinely utilize hydraulic fracturing techniques in our oil and natural gas drilling and completion programs. The process is typically regulated by state oil and natural gas commissions. However, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel under the federal Safe Drinking Water Act, or SDWA, in states where the EPA is the permitting authority and released guidance in February 2014 on regulatory requirements for companies that plan to conduct hydraulic fracturing using diesel in those states. Congress has also considered legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process and various agencies have considered or pursued rulemakings related to hydraulic fracturing.

Some states, including those in which we operate, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations under certain circumstances. For example, in 2011 Texas adopted the Hydraulic Fracturing Chemical Disclosure Rule, requiring public disclosure of chemicals in fluids used in the hydraulic fracturing process for drilling permits issued after February 1, 2012. In addition, the OKCC has adopted rules prohibiting water pollution resulting from hydraulic fracturing operations and requiring disclosure of chemicals used in hydraulic fracturing. The mandatory disclosure of information regarding the constituents of hydraulic fracturing fluids could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based upon allegations that specific chemicals used in the fracturing process could adversely affect the environment.

The Texas Commission on Environmental Quality has imposed more stringent emissions, monitoring, inspection, maintenance, and repair requirements on Barnett Shale operators to minimize Volatile Organic Compound, or VOC, releases.

In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. If state, local, or municipal legal restrictions are adopted in areas where we are currently conducting operations, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

There are also certain governmental reviews conducted that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality coordinated an administration wide review of hydraulic fracturing practices, and a committee of the United States House of Representatives has conducted an investigation of hydraulic fracturing practices. Furthermore, a number of federal agencies are analyzing, or have been requested to review, a variety of environmental issues associated with hydraulic fracturing. On December 13, 2016, the EPA released a study of the potential adverse effects that hydraulic fracturing activities (including water acquisition, chemical mixing, well injection, and disposal and reuse) may have on water quality and public health, concluding that there is scientific evidence that hydraulic fracturing activities could impact drinking water resources in the United States under some circumstances.

The EPA finalized a rule prohibiting discharges of wastewater resulting from hydraulic fracturing to publicly owned treatment works. The EPA is also conducting a study of private wastewater treatment facilities, referred to as centralized waste treatment, or CWT, facilities, accepting oil and gas extraction wastewater and will evaluate whether to revise discharge limits from CWT facilities. In addition, the U.S. Department of Energy's Natural Gas Subcommittee of the Secretary of Energy Advisory Board conducted a review of hydraulic fracturing issues and practices and made recommendations to better protect the environment from drilling using hydraulic fracturing completion methods. Ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the Safe Drinking Water Act, the Toxic Substances Control Act, or other statutory and/or regulatory mechanisms.

Also, in 2015, the U.S. Department of the Interior’s Bureau of Land Management, or BLM, adopted rules regarding well stimulation, chemical disclosures and other requirements for hydraulic fracturing on federal and Indian lands; however, these rules were rescinded by rule in December 2017. Effective December 2016, the NPS, finalized updates to its regulations governing non-federal oil and gas rights, affecting various approval exemptions and addressing well stimulation, chemical disclosures and other requirements for hydraulic fracturing. However, this regulation may be further reviewed for potential rescission or revision pursuant to Executive Order No. 13783 titled “Promoting Energy Independence and Economic Growth,” dated March 28, 2017.

In addition, as discussed further below, state and federal regulatory agencies recently have focused on seismic events potentially associated with oil and gas operations, including injection well disposal and the hydraulic fracturing process.

Table of Contents

Further, since 2012, oil and gas operations (production, processing, transmission, storage and distribution) have been subject to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS, programs. The EPA rules also include NSPS standards for completions of hydraulically fractured gas wells. These standards include the reduced emission completion techniques developed in the EPA's Natural Gas STAR program along with pit flaring of gas not sent to the gathering line. The standards are applicable to newly drilled and fractured wells as well as existing wells that are refractured. Further, the regulations under NESHAPS include maximum achievable control technology, or MACT, standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. In October 2012, several challenges to the EPA's rules were filed by various parties, including environmental groups and industry associations. In a January 16, 2013 unopposed motion to hold this litigation in abeyance, the EPA indicated that it may reconsider some aspects of the rules. The EPA has since reconsidered several aspects of the rules and may continue to make changes. For example in 2015, the EPA finalized a final rule defining "low pressure gas well" and removing "connected in parallel" from the definition of storage vessels in the New Source Performance Standard and in March 12, 2018 adopted amendments to two narrow provisions for the collection of fugitive emission components at well sites and compressor stations. Further, on October 15, 2018, EPA proposed rule to amend certain of these rules related to fugitive emissions requirements, well site pneumatic pump standards, the requirements for certification of closed vent systems by a professional engineer, and the alternative means of emissions limitations provisions. Depending on the outcome of judicial proceedings and regulatory actions, the rules may be further modified or rescinded or the EPA may issue new rules as proposed or otherwise. We have reported some of our facilities as being subject to these rules and have incurred, and will continue to incur, costs to control emissions, and to satisfy reporting and other administrative requirements associated with these rules. We continue to evaluate the effect these rules will have on our business. In addition, the EPA finalized new rules to regulate emissions of methane and volatile organic compounds from new and modified sources in the oil and gas sector effective August 2, 2016. The EPA also finalized a rule regarding the alternative criteria for aggregating multiple small surface sites into a single source for air quality permitting purposes. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting processes and requirements across the oil and gas industry. BLM adopted rules effective on January 17, 2017 to reduce venting, flaring, and leaks during oil and natural gas production activities on onshore federal and Indian leases. EPA delayed some requirements and in September 28 adopted a rule to rescind several requirements and significantly revise others. A challenge to the September 2018 rule is pending in federal court. Increased regulation and attention given to the hydraulic fracturing process could lead to greater opposition, including litigation, to oil and gas production activities using hydraulic fracturing techniques. Additional legislation or regulation could also lead to operational delays or increased operating costs in the production of oil and natural gas, including from the developing shale formations, or could make it more difficult to perform hydraulic fracturing. The adoption of any federal, state or local laws or the implementation of regulations regarding hydraulic fracturing could potentially cause a decrease in the completion of new oil and gas wells, increased compliance costs and time, which could adversely affect our financial position, results of operations and cash flows.

Table of Contents

Federal and state legislative and regulatory initiatives relating to induced seismicity in connection with oil and gas activities could result in increased costs, additional operating restrictions or delays, and litigation risks which could adversely affect our operations

State and federal regulatory agencies recently have focused on a possible connection between an observed increase in minor seismic activity and tremors and both the operation of injection wells used for oil and gas waste waters and the hydraulic fracturing process. When caused by human activity, such events are called induced seismicity. In some instances, operators of injection wells in the vicinity of minor seismic events have reduced injection volumes or suspended operations, often voluntarily. Some state regulatory agencies have modified their regulations to account for induced seismicity. For example, the Texas Railroad Commission rules allow the Commission to modify, suspend, or terminate a permit based on a determination that the permitted injection well activity is likely to be contributing to seismic activity. The OKCC also asserts authority to shut down injection wells that it considers linked to induced seismicity, and has recently taken other steps to regulate injection wells that may contribute to induced seismicity. For example, since 2015 the OKCC has mandated reductions in oil and gas wastewater disposal well volumes to address potential induced seismicity in Oklahoma; implementation has involved reductions of injection or shut-ins of disposal wells. In February 2017, the OKCC issued a directive aimed at limiting the growth in future underground injection disposal rates into the Arbuckle formation in an area with seismicity issues. In February 2018, the OKCC announced seismicity guidelines for hydraulic fracturing operations in the SCOOP and STACK plays. Regulatory agencies are continuing to study possible linkage between injection activity and induced seismicity and also possible linkages of induced seismicity to the hydraulic fracturing process. Third-party lawsuits for property damage and other remedies based on allegations of induced seismicity have been brought against other energy companies.

Climate change legislation or regulations restricting emissions of greenhouse gases could result in increased operating costs and reduced demand for the oil, natural gas and NGLs we produce; and actual impacts of climate change like extreme weather conditions could adversely affect our operations.

In December 2009, the EPA officially published its findings that emissions of carbon dioxide, methane and other greenhouse gases, or GHGs, present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on its findings, the EPA promulgated regulations to restrict emissions of GHGs under existing provisions of the federal Clean Air Act, including one rule that requires a reduction in emissions of GHGs from motor vehicles and another that regulates emissions of GHGs from certain large stationary sources. In addition, on October 30, 2009, the EPA published a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the United States. On November 9, 2010, the EPA issued final rules to expand its existing GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage and distribution facilities with reporting of GHG emissions from such facilities required on an annual basis. In 2015, the EPA added reporting of GHG emissions from gathering and boosting systems, completions and workovers of oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines to the GHG reporting rule. We are currently required to monitor and report GHG emissions under this rule, and operational and/or regulatory changes could increase the burden of compliance with GHG emissions monitoring and reporting requirements.

As previously mentioned, federal regulations require methane reductions from new or modified oil and gas sources. On November 10, 2016, the EPA issued a final ICR that would have required numerous oil and gas companies to provide information regarding methane emissions from existing oil and gas facilities, but EPA withdrew the ICR on March 2, 2017. The U.S. Congress has from time to time considered adopting legislation to reduce emissions of GHGs and almost one half of the states have already taken legal measures to reduce emissions of GHGs primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil, natural gas and NGLs we produce. In addition, international, federal, regional and local regulatory initiatives that target GHGs could adversely affect the marketability of the oil and natural gas we produce.

In 2015, the United States participated in the United Nations Conference on Climate Change, which led to the creation of the Paris Agreement. The Paris Agreement came into force on November 4, 2016, requiring, countries to review and "represent a progression" in their intended nationally determined contributions, which set GHG emission reduction goals, every five years beginning in 2020. The United States' has expressed an intention to withdraw from participation in the Paris Agreement, but some state and local governments have expressed intentions to take GHG-related actions. In connection with the decision to adopt the Paris Agreement, the Intergovernmental Panel on Climate Change (the "IPCC") prepared a special report focused on the impacts of a specific increase in the average global temperature above pre-industrial levels and related GHG emission pathways, which was released on October 6, 2018 ("2018 IPCC Report"). The 2018 IPCC Report concludes that severe impacts of climate change could arise with a global warming of 1.5ºC above pre-industrial levels and that, if the increase continues at the current rate, global warming is likely to reach this temperature rise between 2030 and 2052. The report concludes that the measures set forth in the Paris Agreement are insufficient and that more aggressive targets and measures will be needed. Due to the uncertainties surrounding the regulation of and other risks associated with GHG emissions, we cannot predict the financial impact of related developments on our operations. To the extent adopted, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations.

In addition, there has been public discussion that climate change may be associated with extreme weather conditions such as more intense hurricanes, thunderstorms, tornados and snow or ice storms, as well as rising sea levels. Another possible consequence of climate change is increased volatility in seasonal temperatures. Some studies indicate that climate change could cause some areas to experience temperatures substantially colder than their historical averages. Extreme weather conditions can interfere with our production and increase our costs and damage resulting from extreme weather may not be fully insured. However, at this time we are unable to determine the extent to which climate change may lead to increased storm or weather hazards affecting our operations.

We may face unanticipated water and other waste disposal costs.

We may be subject to regulation that restricts our ability to discharge water produced as part of our oil or gas production operations. Productive zones frequently contain water that must be removed in order for the oil or gas to produce, and our ability to remove and dispose of sufficient quantities of water from the various zones will determine whether we can produce oil or gas in commercial quantities. The produced water currently is transported from the lease and injected into disposal wells. Some states, including Oklahoma and Texas, also assert the authority to shut down disposal wells that are deemed to contribute to induced seismicity, or seismic activity that is caused by human activity. Since 2015, the OKCC has implemented a plan calling for mandatory reductions in oil and gas wastewater disposal well volumes to address potential induced seismicity in Oklahoma. Further, in February 2017, the OKCC issued a directive aimed at limiting the growth in future underground injection disposal rates into the Arbuckle formation in an area with seismicity issues. The availability of disposal wells with sufficient capacity to receive all of the water produced from our wells may affect our ability to produce our wells. Also, the EPA has prohibited the disposal of wastewater from hydraulic fracturing into publicly owned treatment facilities through a "zero discharge" pretreatment standard. The EPA is also conducting a study of private wastewater treatment facilities, referred to as centralized waste treatment, or CWT, facilities, accepting oil and gas extraction wastewater and will evaluate whether to revise discharge limits from CWT facilities. Therefore, across the oil and gas industry, the cost to transport and dispose of that water, including the cost of complying with regulations concerning water disposal, may increase. This increase may reduce our profitability.

If water produced from our projects fails to meet the quality requirements of applicable regulatory agencies, our wells produce water in excess of the applicable volumetric permit limits, the disposal wells fail to meet the requirements of all applicable regulatory agencies, or we are unable to secure access to disposal wells with sufficient capacity to accept all of the produced water, we may have to shut in wells, reduce drilling activities, or upgrade facilities for water handling or treatment. The costs to dispose of this produced water may increase if any of the following occur:

- we cannot obtain future permits from applicable regulatory agencies;
- water of lesser quality or requiring additional treatment is produced;
- our wells produce excess water;

- new laws and regulations require water to be disposed in a different manner; or
- costs to transport the produced water to the disposal wells increase.

Table of Contents

We conduct a substantial portion of our operations through farm outs, areas of mutual interest and other joint development agreements. These agreements subject us to additional risks that could have a material adverse effect on the success of these operations, our financial position and our results of operations.

We conduct a substantial portion of our operations through joint development agreements with third parties, including ExxonMobil. We may also enter into other joint development agreements in the future. These third parties may have obligations that are important to the success of the joint development agreement, such as the obligation to contribute capital or pay carried or other costs associated with the joint development agreement. The performance of these third party obligations, including the ability of the third parties to satisfy their obligations under these arrangements, is outside our control. If these parties do not satisfy their obligations under these arrangements, our business may be adversely affected.

Our joint development agreements may involve risks not otherwise present when exploring and developing properties directly, including, for example:

- our joint development partners may share certain approval rights over major decisions;
- our joint development partners may not pay their share of the joint development agreement obligations, leaving us liable for their share of joint development liabilities;
- we may incur liabilities as a result of an action taken by our joint development partners;
- our joint development partners may be in a position to take actions contrary to our instructions or requests or contrary to our policies or objectives; and
- disputes between us and our joint development partners may result in delays, litigation or operational impasses.

The risks described above, the failure to continue our joint ventures or to resolve disagreements with our joint development partners could adversely affect our ability to transact the business of such joint development, which would in turn negatively affect our financial condition and results of operations.

We are subject to cyber security risks. A cyber incident could occur and result in information theft, data corruption, operational disruption or financial loss.

Our business has become increasingly dependent upon digital technologies, including information systems, infrastructure and cloud applications, to operate our businesses, and the maintenance of our financial and other records has long been dependent upon such technologies. The U.S. government has issued public warnings that indicate that energy assets might be specific targets of cyber security threats. Deliberate attacks on, or unintentional events affecting, our systems or infrastructure, the systems or infrastructure of third parties or the cloud could lead to corruption or loss of our proprietary data and potentially sensitive data, delays of delivery of natural gas and NGLs, difficulty in completing and settling transactions, challenges in maintaining our books and records, communication interruptions, environmental damage, personal injury, property damage and other operational disruptions, as well as damage to our reputation, financial condition and cash flows. Further, as cyber incidents continue to evolve, we may be required to expend additional resources to continue to modify or enhance protective measures or to investigate and remediate any vulnerability to cyber incidents. In addition, new U.S. laws and regulations governing data privacy and the unauthorized disclosure of personal information may potentially elevate our compliance costs. Any failure by us to comply with these laws and regulations, including as a result of a cyber incident, could result in significant penalties and liability to us. Additionally, if we acquire a company that has violated or is not in compliance with applicable data protection laws, we may incur significant liabilities and penalties as a result.

Loss of our information and computer systems could adversely affect our business.

We are heavily dependent on our information systems and computer based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure, possible consequences include our loss of communication links, inability to find, produce, process and sell oil, natural gas and NGLs and inability to

Table of Contents

automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material adverse effect on our business.

Risks Relating to Financings and Ownership:

We may be unable to continue as a going concern.

We have substantial debt obligations and our ongoing capital and operating expenditures will vastly exceed the revenue we expect to receive from our operations in the near future. If we are unable to raise substantial additional funding or consummate significant asset sales on a timely basis and/or on acceptable terms, we may be required to significantly curtail our exploration, development and production activities.

The consolidated financial statements included in this Annual Report on Form 10–K have been prepared on a going concern basis of accounting, which contemplates the realization of assets and the satisfaction of liabilities in the normal course of business. The consolidated financial statements do not reflect any adjustments that might be necessary should we be unable to continue as a going concern. Our ability to continue as a going concern is subject to, among other factors, our ability to monetize assets, our ability to obtain financing or refinance existing indebtedness, our ability to continue our cost cutting efforts, the production rates achieved from our discoveries, oil and natural gas prices, the number of commercially viable hydrocarbon discoveries made and the quantities of hydrocarbons discovered, the speed and cost with which we can bring such discoveries to production and the actual cost of exploration, appraisal and development of our prospects. There can be no assurance that we will be able to obtain additional funding on a timely basis and on satisfactory terms, or at all. In addition, no assurance can be given that any such funding, if obtained, will be adequate to meet our capital needs and support our growth. If additional funding cannot be obtained on a timely basis and on satisfactory terms, then our operations would be materially negatively impacted.

If we become unable to continue as a going concern, we may find it necessary to file a voluntary petition for reorganization under the Bankruptcy Code in order to provide us additional time to identify an appropriate solution to our financial situation and implement a plan of reorganization aimed at improving our capital structure. For additional information, please see “Item 8. Financial Statements and Supplementary Data” contained herein.

The report of our independent registered public accounting firm contains an explanatory paragraph as to our ability to continue as a going concern, which could prevent us from obtaining new financing on reasonable terms, or at all.

We have incurred significant operating and net losses and may continue to incur net operating losses. Without additional sources of capital or a significant restructuring of our balance sheet, these conditions raise substantial doubt about our ability to continue as a going concern, which means that we may be unable to continue operations for the foreseeable future or realize assets and discharge liabilities in the ordinary course of operations. As a result, our independent registered public accounting firm included an explanatory paragraph with respect to this uncertainty in its report that is included with our financial statements in this Annual Report on Form 10-K. Such an opinion may materially and adversely affect the price per share of our common stock and may otherwise limit our ability to raise additional funds through the issuance of debt or equity securities or otherwise. Further, the perception that we may be unable to continue as a going concern may impede our ability to raise additional funds or operate our business due to concerns with respect to our ability to discharge our contractual obligations.

We have prepared our financial statements on a going concern basis, which contemplates that we will be able to realize our assets and discharge our liabilities and commitments in the ordinary course of business. Our financial statements included in this Annual Report on Form 10-K do not include any adjustments to reflect the possible future effects on the recoverability and classification of assets or the amounts and classification of liabilities that may result from the outcome of this uncertainty. Without additional capital or a significant restructuring of our balance sheet, however, we may be unable to continue as a viable entity, in which case our stockholders may lose all or some of their investment in us.

We will be required to make payments under the Tax Receivable Agreement for certain tax benefits we may receive (or be deemed to receive), and the amounts of such payments could be significant.

We entered into the Tax Receivable Agreement with JEH and the Class B shareholders. This agreement generally provides for the payment by us of 85% of the amount of cash savings, if any, in U.S. federal, state and local income tax or franchise tax that we actually realize (or are deemed to realize in certain circumstances) as a result of (i) the tax basis increases resulting from the Class B shareholders' exchange of JEH Units for shares of Class A common stock (or resulting from a sale of JEH Units to us for cash) and (ii) imputed interest deemed to be paid by us as a result of, and

Table of Contents

additional tax basis arising from, any payments we make under the Tax Receivable Agreement. In addition, payments we make under the Tax Receivable Agreement will be increased by any interest accrued from the due date (without extensions) of the corresponding tax return.

The payment obligations under the Tax Receivable Agreement are our obligations and not obligations of JEH. For purposes of the Tax Receivable Agreement, cash savings in tax generally are calculated by comparing our actual tax liability to the amount we would have been required to pay had we not been able to utilize any of the tax benefits subject to the Tax Receivable Agreement. Any payments are made within a designated period of time following the filing of the tax return where we utilize such tax benefits to reduce taxes in a given year. The term of the Tax Receivable Agreement will continue until all such tax benefits have been utilized or expired, unless we exercise our right to terminate the Tax Receivable Agreement by making the termination payment specified in the agreement.

The actual increase in tax basis, as well as the amount and timing of any payments under the Tax Receivable Agreement, will vary depending upon a number of factors, including the timing of the exchanges of JEH Units, the price of Class A common stock at the time of each exchange, the extent to which such exchanges are taxable, the amount and timing of the taxable income we generate in the future and the tax rate then applicable, and the portion of our payments under the Tax Receivable Agreement constituting imputed interest or depletable, depreciable or amortizable basis. We expect that the payments that we will be required to make under the Tax Receivable Agreement could be substantial.

The payments under the Tax Receivable Agreement will not be conditioned upon a holder of rights under the Tax Receivable Agreement having a continued ownership interest in either JEH or us.

In certain circumstances including transactions involving a change in control, significant payments under the Tax Receivable Agreement may be accelerated and/or significantly exceed the actual benefits, if any, we realize in respect of the tax attributes subject to the Tax Receivable Agreement.

Under certain circumstances, we could become obligated to make significant payments under our Tax Receivable Agreement that could exceed or represent a substantial portion of our liquidity and market capitalization. These payment obligations could be to persons without significant equity ownership in us at the time such obligation arises. If we elect to terminate the Tax Receivable Agreement early or it is terminated early due to certain mergers or other changes of control, we would be required to make an immediate payment equal to the present value of the anticipated future tax benefits subject to the Tax Receivable Agreement. Such calculation of anticipated future tax benefits will be based upon certain assumptions and deemed events set forth in the Tax Receivable Agreement, including the assumptions that (i) we have sufficient taxable income to fully utilize such benefits, (ii) any JEH Units that the Class B shareholders or their permitted transferees own on the termination date are exchanged for shares of our Class A common stock on the termination date and (iii) the amount of future depletion deductions to which we are entitled is based on recoverable reserves and rates of recovery reflected in the most recent reserve reports and estimates available on the termination date. Any early termination payment may be made significantly in advance of the actual realization, if any, of such future benefits.

In these situations, our obligations under the Tax Receivable Agreement could have a substantial negative impact on our liquidity and could have the effect of delaying, deferring or preventing certain mergers, asset sales, other forms of business combinations or other changes of control due to the additional transaction cost a potential acquirer may attribute to satisfying such obligations. For example, if the Tax Receivable Agreement had been terminated at December 31, 2018, we estimate that the termination payment would be approximately $52.0 million (calculated based on the 21% U.S. federal corporate income tax rate under the recently enacted Tax Cuts and Jobs Act, and applicable state and local income tax rates and using a discount rate equal to LIBOR, plus 100 basis points, applied against the anticipated undiscounted liability and assuming a market value of our Class A common stock equal to

$0.34 per share, the closing price on December 31, 2018). The foregoing is merely an estimate and the actual payment could differ materially. There can be no assurance that we will be able to finance our obligations under the Tax Receivable Agreement.

Table of Contents

Payments under the Tax Receivable Agreement will be based on the tax reporting positions that we will determine. The holders of rights under the Tax Receivable Agreement will not reimburse us for any payments previously made under the Tax Receivable Agreement if such basis increases or other benefits are subsequently disallowed, except that excess payments made to any Class B shareholder will be netted against payments otherwise to be made, if any, to such Class B shareholder after our determination of such excess. As a result, in such circumstances, we could make payments that are greater than our actual cash tax savings, if any, and may not be able to recoup those payments, which could adversely affect our liquidity.

We are a smaller reporting company and benefit from certain reduced governance and disclosure requirements, including that our independent registered public accounting firm is not required to attest to the effectiveness of our internal control over financial reporting. We cannot be certain if the omission of reduced disclosure requirements applicable to smaller reporting companies will make our common stock less attractive to investors.

Currently, we are a “smaller reporting company,” meaning that our outstanding common stock held by nonaffiliates had a value of less than $250 million at the end of our most recently completed second fiscal quarter. As a smaller reporting company, we are not required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act, meaning our auditors are not required to attest to the effectiveness of the Company’s internal control over financial reporting. As a result, investors and others may be less comfortable with the effectiveness of the Company’s internal controls and the risk that material weaknesses or other deficiencies in internal controls go undetected may increase. In addition, as a smaller reporting company, we take advantage of our ability to provide certain other less comprehensive disclosures in our SEC filings, including, among other things, providing only two years of audited financial statements in annual reports and simplified executive compensation disclosures. Consequently, it may be more challenging for investors to analyze our results of operations and financial prospects, as the information we provide to stockholders may be different from what one might receive from other public companies in which one hold shares. As a smaller reporting company, we are not required to provide this information.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce our cash flow available for drilling and place us at a competitive disadvantage. Recent and continuing disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. A significant reduction in our cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

The Jones family and certain other stockholders control a significant percentage of Jones Energy, Inc.’s voting power and have the ability to take actions that may conflict with your interests.

As of December 31, 2018, the Jones family, Metalmark Capital and affiliates of JVL Advisors, L.L.C. held approximately 42.1% of the combined voting power of Jones Energy, Inc. These stockholders are entitled to act separately in their own respective interests with respect to their ownership interests in Jones Energy, Inc., and collectively have the ability to substantially influence the election of the members of our board of directors, thereby potentially controlling our management and affairs. In addition, they have significant influence over all matters that require approval by our stockholders, including mergers and other material transactions.

If we fail to develop or maintain an effective system of internal controls, we may not be able to report our financial results accurately or prevent fraud, which would likely have a negative impact on the market price of our common stock.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and to operate successfully as a publicly traded company. To comply with the requirements of being a publicly traded company, we may need to implement additional financial and management controls, reporting systems and procedures and hire additional accounting, finance, tax and legal staff. Our efforts to develop and maintain our internal controls may not be successful, and we may be unable to maintain effective controls over our financial processes and reporting in the future or to comply with our obligations under Section 404 of the Sarbanes Oxley Act of 2002, which we refer to as Section 404. For example, Section 404 requires us, among other things, to annually review and report on the effectiveness of our internal controls over financial reporting. Any failure to develop, implement or maintain effective

Table of Contents

internal controls or to improve our internal controls could harm our operating results or cause us to fail to meet our reporting obligations. Given the difficulties inherent in the design and operation of internal controls over financial reporting, we can provide no assurance as to our conclusions about the effectiveness of our internal controls, and we may incur significant costs in our efforts to comply with Section 404. If one or more material weaknesses persist or if we fail to establish and maintain effective internal control over financial reporting, our ability to accurately report our financial results could be adversely affected. Ineffective internal controls could also subject us to regulatory scrutiny and a loss of confidence in our reported financial information, which could have an adverse effect on our business.

The loss of senior management or technical personnel could adversely affect our operations.

Our success will depend to a large extent upon the efforts and abilities of our executive officers and key operations personnel. The loss of the services of one or more of these key employees could have a material adverse effect on us. We do not maintain insurance against the loss of any of these individuals. Our business will also be dependent upon our ability to attract and retain qualified personnel. Since the fourth quarter of 2014, the prices of oil, natural gas and NGLs were extremely volatile and declined significantly. Key employees may depart because of uncertainty during times of commodity price volatility. Acquiring and keeping these personnel could prove more difficult or cost substantially more than estimated. This could cause us to incur greater costs, or prevent us from pursuing our development and exploitation strategy as quickly as we would otherwise wish to do.

We currently have no plans to pay regular dividends on our common stock, so you may not receive funds without selling your common stock.

We currently have no plans to pay regular dividends on our Class A common stock. Any payment of dividends in the future will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition and business opportunities, the restrictions in our debt agreements, and other considerations that our board of directors deems relevant. Accordingly, you may have to sell some or all of your Class A common stock in order to generate cash flow from your investment.

Future sales of our common stock in the public market or the issuance of securities senior to our common stock, or the perception that these sales may occur, could adversely affect the trading price of our common stock and our ability to raise funds in stock offerings.

A large percentage of our shares of common stock are held by a relatively small number of investors. Further, we entered into registration rights agreements with certain of those investors pursuant to which we have filed a registration statement with the SEC to facilitate potential future sales of such shares by them. Sales by us or our stockholders of a substantial number of shares of our common stock in the public markets, or even the perception that these sales might occur, could cause the market price of our Class A common stock to decline or could impair our ability to raise capital through a future sale of, or pay for acquisitions using, our equity securities.

We may issue common stock or other equity securities senior to our common stock in the future for a number of reasons, including to finance acquisitions, to adjust our leverage ratio, and to satisfy our obligations upon the exercise of warrants and options, or for other reasons. We cannot predict the effect, if any, that future sales or issuances of shares of our common stock or other equity securities, or the availability of shares of common stock or such other equity securities for future sale or issuance, will have on the trading price of our common stock.

We will incur corporate income tax liabilities on taxable income allocated to us by JEH with respect to JEH Units we own, which may be substantial. JEH is required to make cash tax distributions under its operating agreement. JEH's ability to make tax distributions, and our ability to pay taxes and the Tax Receivable Agreement liability may be limited by our structure and available liquidity. To the extent that we incur cash income tax liabilities or JEH is required to make cash tax distributions and cash payments of the Tax Receviable Agreement liability it would impact our liquidity and reduce cash available for other uses.

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 such unitholders through the end of each relevant quarter, as adjusted to take into account our good faith projections 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 described below. During 2016, JEH generated taxable income, resulting in the payment during 2016 of $17.3 million in cash tax distributions to JEH unitholders (other than us). As a result of JEH’s 2016 taxable income (all of which is passed-through and taxed to us and JEH’s other unitholders), during 2017 we made further income tax payments to federal and state taxing authorities of $2.3 million and JEH made further tax distributions to JEH unitholders (other than us) of $0.6 million. During 2017, JEH did not generate taxable income, therefore we did not make any additional tax payments nor did JEH make any additional tax distributions other than those made as a result of 2016 JEH taxable income. Based on our 2018 operating activity and our initial 2019 operating budget and information available as of this filing, we do not anticipate that we will be required to make any additional tax payments or that JEH will make any additional tax distributions during 2019. Estimating the tax distributions required under the operating agreement is imprecise by nature, highly uncertain, and dependent upon a variety of factors.

We are classified as a corporation for U.S. federal income tax purposes and, in most states in which JEH does business, for state income tax purposes. Under current law, we are subject to U.S. federal income tax at rates of up to 21%, and to state income tax at rates that vary from state to state, on the net income allocated to us by JEH with respect to the JEH Units we own. We are a holding company with our sole asset consisting of our ownership in JEH and have no independent means of generating revenue. JEH is classified as a partnership for federal income tax purposes and as such is not subject to federal income tax (other than as a withholding agent). Instead, taxable income is allocated to holders of JEH Units, including the JEH Units we own. Under the terms of its operating agreement, JEH is obligated to make tax distributions to holders of its units, including us, subject to the conditions described below. Our ability to cause JEH to make tax distributions, which generally will be pro rata with respect to all outstanding JEH Units, in an amount sufficient to allow us to pay our taxes and make any payments due under the Tax Receivable Agreement, is subject to various factors, including the cash requirements and financial condition of JEH, compliance by JEH or its subsidiaries with restrictions, covenants and financial ratios related to existing or future indebtedness, including under our notes and the Revolver, and other agreements entered into with third parties. As a result, it is possible that Jones Energy, Inc. will not have sufficient cash to pay taxes and make payments under the Tax Receviable Agreement liability.

See “Risk Factors—We will be required to make payments under the Tax Receivable Agreement for certain tax benefits we may receive (or be deemed to receive), and the amounts of such payments could be significant.”

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

The information required by Item 2. is contained in Item 1. Business.

Item 3. Legal Proceedings

We are from time to time subject to, and are presently involved in, litigation or other legal proceedings arising out of the ordinary course of business. None of these legal proceedings are expected to have a material adverse effect on our financial condition, results of operations or cash flow. With respect to these proceedings, our management believes that we will either prevail, have adequate insurance coverage or have established appropriate reserves to cover potential liabilities. Any costs that management estimates may be paid related to these proceedings or claims are accrued when the liability is considered probable and the amount can be reasonably estimated. There can be no assurance, however, as to the ultimate outcome of any of these matters, and if all or substantially all of these legal proceedings were to be determined adversely to us, there could be a material adverse effect on our financial condition, results of operations and cash flow.

See Note 17, “Commitments and Contingencies—Litigation,” in the Notes to Consolidated Financial Statements for further discussion.

Item 4. Mine Safety Disclosures

Not applicable.

Table of Contents

Part II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our Class A common stock was listed on the New York Stock Exchange ("NYSE") under the symbol "JONE" between July 2013 and November 2018. The Class A shares transitioned from the NYSE to trading on the OTCQX on November 27, 2018 retaining its ticker symbol "JONE".

On February 20, 2019, the last sale price of our Class A common stock, as reported on the OTCQX, was $0.40 per share. As of February 20, 2019, there were 5,826,217 shares of Class A common stock outstanding held by approximately thirteen stockholders of record and 172,193 shares of Class B common stock outstanding held by one stockholder of record.

Issuer Purchases of Equity Securities

None.

Sales of Unregistered Equity Securities

None.

Securities Authorized for issuance Under Equity Compensation Plans

The following table presents the securities authorized for issuance under the Amended and Restated Jones Energy, Inc. 2013 Omnibus Incentive Plan (the "LTIP") as of December 31, 2018.

Plan Category	Number of Shares to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights ($)	Number of Shares Remaining Available for Future Issuance under Equity Compensation Plans	
Equity compensation plan approved by security holders (1)	—	—	235,286	(2)
Equity compensation plans not approved by security holders	—	—	—	
Total	—	—	235,286	

(1) Our Amended and Restated 2013 Omnibus Incentive Plan (the "LTIP") was approved by our board of directors in May 2016 and took effect on May 4, 2016. The LTIP was also approved by our shareholders at the Annual Meeting of Shareholders on May 4, 2016.

(2) The LTIP may consist of the following components: restricted stock, stock options, performance awards, restricted stock units, stock appreciation rights, cash awards, dividend equivalents, and other share based awards. The LTIP limits the number of shares that may be delivered pursuant to awards to an aggregate total of 425,265 shares of our

Class A common stock, as adjusted for the effects of the Special Stock Dividend, the preferred stock dividends paid in shares, and the 1-for-20 reverse stock split. Our board of directors had approved total cumulative awards of 189,979 shares of restricted Class A common stock under the LTIP as of December 31, 2018, net of forfeitures and other adjustments that return previously awarded shares to the pool of remaining available shares.

Table of Contents

Item 6. Selected Financial Data

The following table sets forth selected financial data of Jones Energy, Inc. and its predecessor for the years ended December 31, 2018, 2017, 2016, 2015 and 2014. This information should be read in connection with “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “Item 8. Financial Statements and Supplementary Data” presented elsewhere in this report.

	Year Ended December 31,				
(in thousands except per share data)	2018	2017	2016	2015	2014
Operating revenues					
Oil and gas sales	$ 236,873	$ 186,393	$ 124,877	$ 194,555	$ 378,401
Other revenues, net	(516)	2,180	2,970	2,844	2,196
Total operating revenues	236,357	188,573	127,847	197,399	380,597
Operating costs and expenses					
Lease operating	44,921	36,636	32,640	41,027	37,760
Production and ad valorem taxes	12,087	6,874	7,768	12,130	22,556
Transportation and processing costs	3,368	—	—	—	—
Exploration	8,157	14,145	6,673	6,551	3,453
Depletion, depreciation and amortization	173,904	167,224	153,930	205,498	181,669
Impairment of oil and gas properties	1,331,785	149,648	—	—	—
Accretion of ARO liability	1,066	960	1,263	1,087	770
General and administrative	31,204	29,892	29,640	33,388	25,763
Other operating	250	—	199	4,188	—
Total operating expenses	1,606,742	405,379	232,113	303,869	271,971
Operating income (loss)	(1,370,385)	(216,806)	(104,266)	(106,470)	108,626
Other income (expense)					
Interest expense	(89,328)	(51,651)	(53,127)	(64,458)	(41,875)
Gain on debt extinguishment	—	—	99,530	—	—
Net gain (loss) on commodity derivatives	(2,757)	(17,985)	(51,264)	158,753	189,641
Other income (expense)	53,935	56,952	536	317	(4,554)
Other income (expense), net	(38,150)	(12,684)	(4,325)	94,612	143,212
Income (loss) before income tax	(1,408,535)	(229,490)	(108,591)	(11,858)	251,838
Income tax provision					
Current	(5)	(3,585)	3,981	113	53
Deferred	(61,836)	(47,082)	(27,767)	(2,894)	26,165
Total income tax provision (benefit)	(61,841)	(50,667)	(23,786)	(2,781)	26,218
Net income (loss)	(1,346,694)	(178,823)	(84,805)	(9,077)	225,620
Net income (loss) attributable to non-controlling interests	(55,655)	(77,331)	(42,253)	(6,696)	184,484
Net income (loss) attributable to controlling interests	$ (1,291,039)	$ (101,492)	$ (42,552)	$ (2,381)	$ 41,136
Dividends and accretion on preferred stock	(7,737)	(7,924)	(2,669)	—	—
Net income (loss) attributable to common shareholders	$ (1,298,776)	$ (109,416)	$ (45,221)	$ (2,381)	$ 41,136

Earnings (loss) per share:					
Basic - Net income (loss) attributable to common shareholders	$ (271.94)	$ (30.22)	$ (20.79)	$ (1.63)	$ 60.41
Diluted - Net income (loss) attributable to common shareholders	$ (271.94)	$ (30.22)	$ (20.79)	$ (1.63)	$ 60.41
Weighted average Class A shares outstanding:					
Basic	4,776	3,621	2,175	1,458	681
Diluted	4,776	3,621	2,175	1,458	682
Other Supplementary Data:					
EBITDAX (1)	$ 83,282	$ 186,364	$ 187,955	$ 268,417	$ 303,014
Adjusted net income (2)	$ (184,606)	$ (31,126)	$ (15,528)	$ 2,220	$ 68,824

(1) EBITDAX is a non GAAP financial measure. For a definition of EBITDAX and a reconciliation of EBITDAX to our net income, see "—Non GAAP Financial Measures" below.
(2) Adjusted net income is a non GAAP financial measure. For a definition of adjusted net income and a reconciliation of adjusted net income to our net income, see "—Non GAAP Financial Measures" below.

Table of Contents

(in thousands of dollars)	Year Ended December 31, 2018	2017	2016	2015	2014
Statement of Cash Flow Data					
Net cash provided by operating activities	$ 64,108	$ 59,008	$ 25,700	$ 68,849	$ 265,319
Net cash (used in) investing activities	(240,893)	(110,004)	(130,862)	(168,220)	(463,799)
Net cash provided by financing activities	215,777	35,826	117,911	107,698	188,226
Net increase (decrease) in cash	$ 38,992	$ (15,170)	$ 12,749	$ 8,327	$ (10,254)

(in thousands of dollars)	As of December 31, 2018	2017	2016	2015	2014
Balance Sheet Data					
Cash and cash equivalents	$ 58,464	$ 19,472	$ 34,642	$ 21,893	$ 13,566
Other current assets	71,667	85,229	64,680	172,281	230,648
Total current assets	130,131	104,701	99,322	194,174	244,214
Property and equipment, net	273,485	1,599,759	1,746,584	1,639,639	1,642,908
Other long-term assets	1,959	5,603	40,794	101,341	96,363
Total assets	$ 405,575	$ 1,710,063	$ 1,886,700	$ 1,935,154	$ 1,983,485
Current liabilities	$ 109,637	$ 166,487	$ 107,807	$ 67,576	$ 229,132
Long-term debt	982,157	759,316	724,009	837,654	848,636
Other long-term liabilities	25,045	108,585	74,458	93,072	52,367
Mezzanine equity	93,719	89,539	88,975	—	—
Total stockholders' / members' equity	(804,983)	586,136	891,451	936,852	853,350
Total liabilities and stockholders' / members' equity	$ 405,575	$ 1,710,063	$ 1,886,700	$ 1,935,154	$ 1,983,485

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, impairment charges, 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 us to more effectively evaluate our operating performance and compare the results of our operations from period to period and against our peers without regard to our financing methods or capital structure. We exclude the items listed above from net income in arriving at EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. EBITDAX has limitations as an analytical tool and should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with GAAP or as an indicator of our liquidity. Certain items excluded from EBITDAX are significant components in understanding and assessing a company’s financial performance, such as a company’s cost of capital and tax structure, as well as the historical costs of depreciable assets. Our presentation of EBITDAX should not be construed as an inference that our results will be

Table of Contents

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:

	Year Ended December 31,				
(in thousands of dollars)	2018	2017	2016	2015	2014
Reconciliation of net income to EBITDAX					
Net income (loss)	$ (1,346,694)	$ (178,823)	$ (84,805)	$ (9,077)	$ 225,620
Interest expense	89,328	51,651	53,127	64,458	41,875
Exploration expense	8,157	14,145	6,673	6,551	3,453
Income taxes	(61,841)	(50,667)	(23,786)	(2,781)	26,218
Depreciation and depletion	173,904	167,224	153,930	205,498	181,669
Impairment of oil and natural gas properties	1,331,785	149,648	—	—	—
Accretion of ARO liability	1,066	960	1,263	1,087	770
Change in TRA liability	(53,330)	(59,492)	(784)	(1,984)	—
Other non-cash charges	400	2,044	1,202	1,023	376
Stock compensation expense	1,381	6,260	7,425	7,562	4,040
Deferred and other non-cash compensation expense	56	208	804	455	758
Net (gain) loss on derivative contracts	2,757	17,985	51,264	(158,753)	(189,641)
Current period settlements of matured derivative contracts	(50,657)	66,851	123,249	149,801	4,476
Amortization of deferred revenue	(1,555)	(1,854)	(2,384)	(1,960)	(1,154)
(Gain) loss on sale of assets, net of proceeds	(11,830)	127	(14)	3	(297)
(Gain) on debt extinguishment	—	—	(99,530)	—	—
Stand-by rig costs	250	—	—	4,188	—
Financing expenses and other loan fees	105	97	321	2,346	4,851
EBITDAX	$ 83,282	$ 186,364	$ 187,955	$ 268,417	$ 303,014

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.

Table of Contents

The following table provides a reconciliation of net income (loss) as determined in accordance with GAAP to adjusted net income for the periods indicated.

	Year Ended December 31,				
(in thousands except per share data)	2018	2017	2016	2015	2014
Net income (loss)	$ (1,346,694)	$ (178,823)	$ (84,805)	$ (9,077)	$ 225,620
Net (gain) loss on derivative contracts	2,757	17,985	51,264	(158,753)	(189,641)
Current period settlements of matured derivative contracts	(50,657)	66,851	123,249	149,801	4,476
Impairment of oil and gas properties	1,331,785	149,648	—	—	—
Exploration	8,157	14,145	6,673	6,551	3,453
Non-cash stock compensation expense	1,381	6,260	7,425	7,562	4,040
Deferred and other non-cash compensation expense	56	208	804	455	758
(Gain) on debt extinguishment	—	—	(99,530)	—	—
Stand-by rig costs	250	—	—	4,188	—
Financing expenses	3,926	—	—	2,250	3,761
Tax impact of adjusting items (1)	(350,422)	(69,627)	(20,774)	(1,106)	16,357
Change in TRA liability	(53,330)	(59,492)	(784)	(1,984)	—
Change in valuation allowance (2)	268,185	21,719	950	2,333	—
Adjusted net income (loss)	$ (184,606)	$ (31,126)	$ (15,528)	$ 2,220	$ 68,824
Adjusted net income (loss) attributable to non-controlling interests	(10,318)	(8,333)	(9,861)	1,275	56,208
Adjusted net income (loss) attributable to controlling interests	(174,288)	(22,793)	(5,667)	945	12,616
Dividends and accretion on preferred stock	(7,737)	(7,924)	(2,669)	—	—
Adjusted net income (loss) attributable to common shareholders	$ (182,025)	$ (30,717)	$ (8,336)	$ 945	$ 12,616
Earnings per share (basic and diluted):	$ (271.94)	$ (30.22)	$ (20.79)	$ (1.63)	$ 60.41
Net (gain) loss on derivative contracts	0.04	5.84	13.99	(49.12)	(70.73)
Current period settlements of matured derivative contracts	(9.94)	12.90	30.64	45.62	1.67
Impairment of oil and gas properties	269.48	28.51	—	—	—
Exploration	1.58	2.84	1.96	2.18	1.29
Non-cash stock compensation expense	0.26	1.24	1.93	2.34	1.51
Deferred and other non-cash compensation expense	0.01	0.03	0.20	0.14	0.28
(Gain) on debt extinguishment	—	—	(22.63)	—	—
Stand-by rig costs	0.05	—	—	1.04	—
Financing expenses	0.74	—	—	0.50	1.40

Tax impact of adjusting items (1)	(73.39)		(19.20)		(9.21)		(0.67)		22.70	
Change in TRA liability	(11.16)		(16.43)		(0.36)		(1.36)		—	
Change in valuation allowance (2)	56.16		6.01		0.44		1.61		—	
Adjusted earnings per share (basic and diluted)	$ (38.11)		$ (8.48)		$ (3.83)		$ 0.65		$ 18.53	
Weighted average Class A shares outstanding:										
Basic	4,776		3,621		2,175		1,458		681	
Diluted	4,776		3,621		2,175		1,458		682	
Effective tax rate on net income (loss) attributable to controlling interests	23.0	%	25.1	%	35.2	%	38.9	%	35.7	%

(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

(2) Includes adjustment for valuation allowance and IRC Section 382 limitation

(3) All share and earnings per share information presented has been recast to retrospectively adjust for the effects of the Special Stock Dividend distributed on March 31, 2017 and the Reverse Stock Split effective on September 7, 2018, as defined in Note 14, “Stockholders’ and Mezzanine Equity”.

Table of Contents

Item 7. 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 our Consolidated Financial Statements and the Notes to Consolidated Financial Statements appearing elsewhere in this Annual Report on Form 10 K. The following discussion contains "forward looking statements" that are based on management's current expectations, estimates and projections about our business and operations, and that involve risks and uncertainties. Our actual results may differ materially from those currently anticipated and expressed in such forward looking statements as a result of a number of factors, including those we discuss under "Risk Factors," "Cautionary Statement Regarding Forward Looking Statements" and elsewhere in this report.

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 Oklahoma and Texas. Our Chairman of the Board, 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 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 Basin, having concentrated our operations there for over 25 years. We have drilled approximately 965 total wells as operator, including over 780 horizontal wells, since our formation. Our operations are focused on horizontal drilling within two distinct areas in Oklahoma and Texas:

- the Eastern Anadarko Basin—targeting the liquids rich Woodford shale and Meramec formations in the Merge area of the STACK/SCOOP plays (the "Merge"); and
- the Western Anadarko Basin—targeting the liquids rich Cleveland, Granite Wash, Tonkawa and Marmaton formations.

We seek to optimize returns through a disciplined emphasis on controlling costs and promoting operational efficiencies, and we have historically been recognized as one of the lowest-cost drilling and completion operators in the Cleveland formation. Our low-cost drilling expertise has applied directly to our newer operations in the Merge, where the Company plans to spend the majority of its 2019 capital budget.

As of December 31, 2018, our total estimated proved reserves were 68.0 MMBoe, of which 90% were classified as proved developed reserves. Approximately 23% of these total estimated proved reserves consisted of oil, 32% consisted of NGLs, and 45% consisted of natural gas.

2019 Outlook

Management Changes

On January 10, 2019, the Board promoted Thomas Hester, 34, an executive officer of the Company and the Company's principal financial officer and principal accounting officer, to the role of Senior Vice President and Chief Financial Officer. Mr. Hester has served in various finance roles for the Company since April 2010, including most recently as the Vice President of Finance. Prior to his time at the Company, Mr. Hester was an Investment Banking Associate in the Energy Group at Jefferies and was an Investment Banking Analyst in the Natural Resources Group at Bear Stearns & Co. Mr. Hester received his Bachelor of Business Administration in Finance and Accounting from Texas Christian University.

Also on January 10, 2019, Jeff Tanner was transitioned from his role as an Executive Vice President and Chief Operating Officer, to the non-executive role of Executive Vice President of Geosciences, effective immediately.

Following Mr. Tanner’s transition, the Board promoted Kirk Goehring, 34, the Company’s Vice President of Strategy and an executive officer of the Company, to the role of Senior Vice President and Chief Operating Officer, effective immediately. Mr. Goehring has served in various operating, corporate development, and finance roles at the Company since September 2012. Prior to joining the Company, Mr. Goehring was an Associate at Metalmark Capital and an Investment Banking Analyst at Greenhill & Co. and Bear Stearns & Co. Mr. Goehring received his Bachelor of Business Administration from the McCombs School of Business at the University of Texas at Austin.

Table of Contents

Following the changes described above, the Company's executive officers are Carl F. Giesler, Jr., Chief Executive Officer, Thomas Hester, Senior Vice President and Chief Financial Officer, and Kirk Goehring, Senior Vice President and Chief Operating Officer.

Liability Management

We intend to continue to pursue additional liability management opportunities with the goal of decreasing our leverage and increasing our financial flexibility.

Discussions with Certain Beneficial Holders of Our Funded Debt

As previously disclosed, the Company and its advisors have been engaged in discussions with certain beneficial holders of the Company's unsecured funded debt and other securities (the "Holders") regarding a potential transaction addressing the Company's debt and equity (a "Potential Transaction"). To facilitate such discussions, the Company and certain of the Holders entered into a confidentiality agreement (the "Holders NDA") on December 3, 2018.

Additionally, in connection with a Potential Transaction, the Company has been in discussions with Metalmark Capital ("Metalmark") regarding the Tax Receivable Agreement by and between JEH LLC, Metalmark and certain of the Company's current and former owners, dated as of July 29, 2013 (the "Tax Receivable Agreement"). To facilitate such discussions, the Company and Metalmark entered into a confidentiality agreement (the "Metalmark NDA") on January 14, 2019.

Pursuant to the Holders NDA, the Company agreed to publicly disclose, after a specified period of time if certain conditions were met, that the Company and certain of the Holders were engaged in negotiations related to a Potential Transaction and information regarding such negotiations. Pursuant to the Metalmark NDA, the Company agreed to publicly disclose, after a specified period of time if certain conditions were met, that the Company and Metalmark were engaged in negotiations related to the Tax Receivable Agreement and information regarding such negotiations. To satisfy the Company's public disclosure obligations under both the Holders NDA and the Metalmark NDA, the information was furnished in a Form 8-K filed on February 1, 2019.

Also included in the Form 8-K filed on February 1, 2019 were the material terms of a Potential Transaction agreed to be disclosed pursuant to the Holders NDA and the Metalmark NDA. The Company has not agreed to consummate a transaction at this time, including the Potential Transaction. No definitive agreement has been reached with the Holders, Metalmark or any other stakeholder. The Company may continue discussions with Metalmark, the Holders, and/or beneficial holders of its first lien secured notes regarding a Potential Transaction.

Going Concern

As a result of current market conditions, we believe we will require a significant restructuring of our balance sheet within the next twelve months in order to continue as a going concern. As previously disclosed, the Company and its advisors have been engaged in discussions with certain beneficial holders of the Company's funded debt (the "Holders") regarding a potential transaction addressing the Company's debt and equity. We have not yet reached an agreement on mutually acceptable terms and conditions with the Holders regarding a possible transaction. Our current circumstances raise substantial doubt as to the ability of the Company to continue to realize the carrying value of our assets and operate as a going concern.

There can be no assurance that our efforts will result in any agreement or what the terms of any agreement will be. If an agreement is reached and we pursue a restructuring, it may be necessary for us to file a voluntary petition for relief under Chapter 11 of the United States Bankruptcy Code in order to implement the agreement through the confirmation and consummation of a plan of reorganization approved by the bankruptcy court in the bankruptcy proceedings. We also may conclude that it is necessary to initiate Chapter 11 proceedings to implement a restructuring of our obligations even if we are unable to reach an agreement with the Holders regarding the terms of such a restructuring. In either case, such a proceeding could be commenced in the near term. If a plan of reorganization is implemented in a bankruptcy proceeding, it is possible that holders of claims and interests with respect to, or rights to acquire, our equity securities would be entitled to little or no recovery, and those claims and interests may be canceled for little or no consideration. If that were to occur, we anticipate that all or substantially all of the value of all investments in our equity securities would be lost and that our equity holders would lose all or substantially all of their investment. It is also possible that our other stakeholders, including our secured and unsecured creditors, will receive substantially less than the amount of their claims.

The report of the Company's independent registered public accounting firm that accompanies its audited consolidated financial statements in this Annual Report on Form 10-K contains an explanatory paragraph regarding the substantial doubt about the Company's ability to continue as a going concern. The consolidated financial statements do not include any adjustments that might result from the outcome of the going concern uncertainty.

Impairment of Oil and Gas Properties

The Company performs assessments of its long-lived assets to be held and used, including proved oil and gas properties accounted for under the successful efforts method of accounting, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss is indicated if the sum of the expected future cash flows is less than the carrying amount of the assets. In these circumstances, the Company recognizes an impairment loss for the amount by which the carrying amount of the assets exceeds the estimated fair value of the assets. Impairment charges of $1,332.0 million were recognized during the year ended December 31, 2018. See Note 9, "Fair Value Measurement," in the Notes to Consolidated Financial Statements for further information.

Reserves Update

The amount of our proved reserves, as estimated based on SEC pricing and definitions, was 68.0 MMBoe as of December 31, 2018, of which 90% were classified as proved developed reserves. This decrease of 35.1%, from 104.8 MMBoe as of December 31, 2017, was primarily caused by a reduction in proved undeveloped locations due to an anticipated reduction in future capital spending as a result of the Company's limited capital resources available to fund our drilling program.

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.

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.

Capital Expenditures Update

Our 2018 capital expenditures totaled $192.6 million (excluding the impact of asset retirement costs, asset disposals and non-cash impairments of oil and gas properties), of which $149.5 million was utilized to drill and complete operated

Table of Contents

wells. The Company has established an initial capital budget of $60.0 million for 2019, including $48.0 million for drilling completing wells and $12.0 million for workovers, leasing, and other capital projects. We will continue to monitor market conditions and may decide, at a later date, to spend more or less capital for a variety of reasons. Please see “Liquidity and Capital Resources.” All drilling locations classified as proved undeveloped reserves in the year end reserve report are scheduled to be drilled within five years of initial proved reserve booking.

Commodity Price Hedging

The price we receive for our oil, natural gas and NGLs significantly influences our revenue, profitability, liquidity, access to capital and prospects for future growth. Oil and natural gas are commodities and, therefore, their prices can be subject to wide fluctuations in response to relatively minor changes in supply and demand. We believe these prices will likely continue to be volatile in the future.

Due to the inherent volatility in oil and gas prices, we use commodity derivative instruments such as swaps to hedge price risk associated with a significant portion of our anticipated oil, natural gas and NGL production. These instruments allow us to reduce, but not eliminate, the potential effects of variability in cash flow from operations due to fluctuations in commodity prices. The instruments provide only partial protection against declines in oil and gas prices, and may limit our potential gains from future increases in prices. None of these instruments are used for trading purposes. We do not speculate on commodity prices but rather attempt to hedge physical production by individual hydrocarbon product in order to protect returns. The only counterparties to our derivatives are lenders under the Revolver, and our hedge positions are generally reviewed on a monthly basis. We have not designated any of our derivative contracts as fair value or cash flow hedges. The changes in fair value of the contracts are included in net income. We record such derivative instruments as assets or liabilities in the balance sheet. We do not anticipate any substantial changes in our hedging policy.

Historically, to mitigate the risk associated with commodity price fluctuations, we have maintained a high level of hedges relative to our projected production. During the year ended December 31, 2018, 82% of our total production for oil, natural gas and NGLs was hedged. For the years ending December 31, 2019, 2020, and 2021, approximately 62%, 33%, and 0%, respectively, of our estimated total oil, natural gas and NGL production from proved reserves, based on our reserve report as of December 31, 2018, are hedged by commodity derivative contracts, respectively. As of December 31, 2018, the estimated mark-to-market value of our commodity price hedges in 2019 and beyond was an asset of approximately $6.0 million.

Table of Contents

Our open positions as of December 31, 2018 were as follows:

	Year Ending December 31, 2019	2020
Oil positions (1):		
Swaps:		
Hedged volume (MBbl)	540	660
Weighted average price ($/Bbl)	$ 49.95	$ 50.00
Collars:		
Hedged volume (MBbl)	810	—
Floor Price ($/Bbl)	$ 48.52	$ —
Ceiling Price ($/Bbl)	$ 59.64	$ —
Natural gas positions (2):		
Swaps:		
Hedged volume (MMcf)	7,260	8,400
Weighted average price ($/Mcf)	$ 2.84	$ 2.79
Collars:		
Hedged volume (MMcf)	11,890	—
Floor Price ($/Mcf)	$ 2.55	$ —
Ceiling Price ($/Mcf)	$ 3.19	$ —

(1) The oil derivatives are settled based on the month's average daily NYMEX price of West Texas Intermediate Light Sweet Crude.
(2) The natural gas derivatives are settled based on the NYMEX natural gas futures price for the calculation period.

The estimated mark-to-market value of our commodity price hedges in 2019 and beyond was a liability of approximately $8.2 million, incorporating strip pricing as of February 20, 2019 but excluding adjustments for credit risk.

The following table summarizes our commodity derivative contracts outstanding as of February 20, 2019:

	Fiscal Year Ending December 31, 2019	2020
Oil Hedges		
Sold (MBbl)	540	660
Price ($/Bbl)	$ 49.95	$ 50.00
Collars (MBbl)	810	—
Floor ($/Bbl)	$ 48.52	$ —
Ceiling ($/Bbl)	$ 59.64	$ —
Gas Hedges		
Sold (MMcf)	9,820	8,400
Price ($/Mcf)	$ 2.83	$ 2.79
Offset Swaps Purchased (MMcf) (1)	2,560	—

Price ($/Mcf)	$ 2.80	$ —
Collars (MMcf)	11,890	—
Floor ($/Mcf)	$ 2.55	$ —
Ceiling ($/Mcf)	$ 3.19	$ —

Basis of Presentation

Sources of our revenues

We derive our revenue from the production and sale of oil, natural gas and NGLs. Our revenues are a function of oil, natural gas, and NGL production volumes sold and average sales prices received for those volumes. We recognize

57

Table of Contents

revenues when the product is delivered at a fixed or determinable price, title has transferred, and collectability is reasonably assured. Our revenues do not include the effects of our hedging activities and may vary substantially from period to period as a result of changes in production volumes or commodity prices.

Principal components of our cost structure

Lease operating expenses. These are daily costs incurred to bring oil and natural gas out of the ground and to the market, together with the daily costs incurred to maintain our producing properties. Such costs also include maintenance, repairs and workover expenses related to our oil and gas properties. Lease operating expenses include both a portion of costs that are fixed in nature, such as infrastructure costs, as well as variable costs resulting from additional well maintenance and production enhancements. As production increases, our average lease operating expense per barrel of oil equivalent is typically reduced because fixed costs do not increase proportionately with production.

Transportation and processing costs. These are certain transportation and processing costs associated with fixed fee contracts where title transfers to the customer at the tailgate of the processing plant and we pay a gathering and processing fee are recognized at the time of title transfer. These costs are presented as Transportation and processing costs on the Consolidated Statement of Operations.

Exploration. Exploration expense consists of geological and geophysical costs, seismic costs, the costs to drill exploratory wells that do not find proved reserves, and the cost of leases that have been abandoned.

Depreciation, depletion and amortization. Under the successful efforts accounting method that we employ, we capitalize all costs associated with our acquisition, successful exploration, and all development efforts within cost centers classified by producing field. We then systematically expense the costs in each field on a units of production basis based on proved oil and natural gas reserve quantities. We calculate depletion on (i) all capitalized costs, other than the cost of investments in unproved properties and major development projects for which proved reserves cannot yet be assigned, less accumulated amortization; and (ii) the estimated plugging and abandonment costs, net of estimated salvage values. We calculate depreciation on the cost of fixed assets related to our well equipment and other fixed assets over the estimated useful lives.

Impairment of oil and gas properties. This is the cost to reduce the carrying value of each field of proved and unproved oil and gas properties to no more than the fair value of the particular field for which impairment recognition is required. We assess our unproved properties periodically for impairment on a property by property basis based on remaining lease terms, drilling results or future plans to develop acreage.

Accretion of ARO liability. Accretion of ARO liabilities are related to our obligation for retirement of oil and gas wells and facilities. We record these liabilities when we place the assets in service, using discounted present values of the estimated future obligation. We then record accretion of the liabilities as they approach maturity.

General and administrative. These are costs incurred for overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, audit and other fees for professional services and legal compliance.

Interest. The primary component of this line item is the interest paid to lenders. We finance a portion of our working capital requirements and capital expenditures with borrowings under senior notes. We incur interest expense that is affected by both fluctuations in interest rates and our financing decisions.

Table of Contents

Results of Operations

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

sands of dollars except for ion, sales price and average cost data)	Year Ended December 31, 2018	2017	Change	2017	2016	Chang
es:						
	$ 141,219	$ 93,207	$ 48,012	$ 93,207	$ 63,736	$ 29,4
gas	34,694	42,191	(7,497)	42,191	31,434	10,7
	60,960	50,995	9,965	50,995	29,707	21,2
l and gas	236,873	186,393	50,480	186,393	124,877	61,5
et	(516)	2,180	(2,696)	2,180	2,970	(790
perating revenues	236,357	188,573	47,784	188,573	127,847	60,7
nd expenses:						
perating	44,921	36,636	8,285	36,636	32,640	3,99
ion and ad valorem taxes	12,087	6,874	5,213	6,874	7,768	(894
rtation and processing costs	3,368	—	3,368	—	—	—
tion	8,157	14,145	(5,988)	14,145	6,673	7,47
on, depreciation and amortization	173,904	167,224	6,680	167,224	153,930	13,2
ment of oil and gas properties	1,331,785	149,648	1,182,137	149,648	—	149,
on of ARO liability	1,066	960	106	960	1,263	(303
and administrative	31,204	29,892	1,312	29,892	29,640	252
perating	250	—	250	—	199	(199
sts and expenses	1,606,742	405,379	1,201,363	405,379	232,113	173,
ng income (loss)	(1,370,385)	(216,806)	(1,153,579)	(216,806)	(104,266)	(112
come (expenses):						
expense	(89,328)	(51,651)	(37,677)	(51,651)	(53,127)	1,47
debt extinguishment	—	—	—	—	99,530	(99,
n (loss) on commodity derivatives	(2,757)	(17,985)	15,228	(17,985)	(51,264)	33,2
come/(expense)	53,935	56,952	(3,017)	56,952	536	56,4
her income (expense)	(38,150)	(12,684)	(25,466)	(12,684)	(4,325)	(8,3
(loss) before income tax	(1,408,535)	(229,490)	(1,179,045)	(229,490)	(108,591)	(120
tax provision (benefit)	(61,841)	(50,667)	(11,174)	(50,667)	(23,786)	(26,
ome (loss)	(1,346,694)	(178,823)	(1,167,871)	(178,823)	(84,805)	(94,
ome (loss) attributable to trolling interests	(55,655)	(77,331)	21,676	(77,331)	(42,253)	(35,
ome (loss) attributable to controlling s	$ (1,291,039)	$ (101,492)	$ (1,189,547)	$ (101,492)	$ (42,552)	$ (58,
ds and accretion on preferred stock	(7,737)	(7,924)	187	(7,924)	(2,669)	(5,2
ome (loss) attributable to common lders	$ (1,298,776)	$ (109,416)	$ (1,189,360)	$ (109,416)	$ (45,221)	$ (64,
duction volumes:						
Bbls)	2,241	1,964	277	1,964	1,685	279
gas (MMcf)	21,384	20,425	959	20,425	18,842	1,58
MBbls)	2,500	2,418	82	2,418	2,204	214
MBoe)	8,305	7,786	519	7,786	7,029	757
e net (Boe/d)	22,753	21,332	1,421	21,332	19,205	2,12

e sales price, unhedged:						
Bbl), unhedged	$ 63.02	$ 47.46	$ 15.56	$ 47.46	37.83	9.63
gas (per Mcf), unhedged	1.62	2.07	(0.45)	2.07	1.67	0.40
per Bbl), unhedged	24.38	21.09	3.29	21.09	13.48	7.61
ed (per Boe), unhedged	28.52	23.94	4.58	23.94	17.77	6.17
e sales price, hedged:						
Bbl), hedged	$ 46.38	$ 74.91	$ (28.53)	$ 74.91	84.71	(9.80
gas (per Mcf), hedged	1.63	3.50	(1.87)	3.50	3.45	0.05
per Bbl), hedged	18.99	14.30	4.69	14.30	17.25	(2.9
ed (per Boe), hedged	22.42	32.53	(10.11)	32.53	34.96	(2.4
e costs (per BOE):						
perating	$ 5.41	$ 4.71	$ 0.70	$ 4.71	4.64	0.07
ion and ad valorem taxes	1.46	0.88	0.58	0.88	1.11	(0.2
on, depreciation and amortization	20.94	21.48	(0.54)	21.48	21.90	(0.4
and administrative	3.76	3.84	(0.08)	3.84	4.22	(0.3

Table of Contents

Results of Operations—Year ended December 31, 2018 as compared to year ended December 31, 2017

Operating revenues

Oil and gas sales. Oil and gas sales increased $50.5 million, or 27.1%, to $236.9 million for the year ended December 31, 2018, as compared to $186.4 million for the year ended December 31, 2017. The increase was attributable to the increase in commodity prices ($29.5 million) and the increase in production volumes ($21.0 million). The increase in production volumes was driven by the year-over-year increase in producing wells due to continued drilling activity. The average realized oil price, excluding the effects of commodity derivative instruments, increased from $47.46 per Bbl to $63.02 per Bbl, or 32.8%, year over year. The average realized natural gas price, excluding the effects of commodity derivative instruments, decreased from $2.07 per Mcf to $1.62 per Mcf, or 21.7%, year over year. The average realized natural gas liquids price, excluding the effects of commodity derivative instruments, increased from $21.09 per Bbl to $24.38 per Bbl, or 15.6%, year over year. Average daily production increased 6.7% to 22,753 Boe per day for the year ended December 31, 2018 as compared to 21,332 Boe per day for the year ended December 31, 2017.

Costs and expenses

Lease operating. Lease operating expense increased by $8.3 million, or 22.7%, to $44.9 million for the year ended December 31, 2018, as compared to $36.6 million for the year ended December 31, 2017. The increase in lease operating expenses is attributable to the increase in number of producing wells, primarily as a result of our continued drilling program in the Merge area. On a per unit basis, lease operating expense increased $0.70 per Boe, or 14.9%, from $4.71 per Boe in the year ended December 31, 2017 to $5.41 per Boe in the year ended December 31, 2018, primarily due to higher operating costs in the Merge area associated with new producing wells.

Transportation and processing costs. In accordance with ASC 606, the Company now records transportation and processing costs that are incurred before control of its product has transferred to the customer (i.e. fixed fee contracts) as a separate expense line item on the Consolidated Statement of Operations. Prior to the adoption of ASC 606, these transportation and processing costs were recorded as a reduction of Oil and gas sales on the Consolidated Statement of Operations. Transportation and processing costs for the year ended December 31, 2018 were $3.4 million.

Production and ad valorem taxes. Production and ad valorem taxes increased by $5.2 million, or 75.4%, to $12.1 million for the year ended December 31, 2018, as compared to $6.9 million for the year ended December 31, 2017. During 2017, the Company's applications for High-Cost Gas Incentive refunds and Low-Producing Gas Incentive refunds in Texas were approved for qualified wells on which taxes were initially paid between October 2012 and April 2017. The Company received net production tax refunds of $3.9 million during the year ended December 31, 2017. During the year ended December 31, 2018, the Company received net production tax refunds of $0.1 million for High-Cost Gas Incentive refunds and Low-Producing Gas Incentive refunds in Texas and Oklahoma for qualified wells on which taxes were initially paid between January 2014 and June 2017. These refunds were recorded as a reduction in Production and ad valorem taxes on the Company’s Consolidated Statement of Operations. Production taxes, excluding the impact of these refunds, increased from $8.9 million for the year ended December 31, 2017 to $10.1 million for the year ended December 31, 2018. The increase was attributable to the increase in production volumes. 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 increased $0.1 million, from $1.8 million for the year ended December 31, 2017 to $1.9 million for the year ended December 31, 2018. The average effective rate excluding the impact of ad valorem taxes increased from 2.7% for the year ended December 31, 2017 to 4.3% for the year ended December 31, 2018.

Exploration. Exploration expense decreased from $14.1 million for the year ended December 31, 2017 to $8.2 million for the year ended December 31, 2018. The Company recognized charges for lease abandonment of $4.2 million during 2018, as compared to $11.0 million during 2017, relating to certain leases that the Company decided during the respective year not to develop and to let lapse. Spending during 2018 primarily related to geological data and seismic processing associated with unproved acreage, focused mainly in the Eastern Anadarko Basin. No exploratory wells resulted in exploration expense during either year.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $6.7 million, or 4.0%, to $173.9 million for the year ended December 31, 2018, as compared to $167.2 million for the year ended December 31, 2017. The increase was primarily driven by capital spending throughout the year related to our continued drilling program in the Merge area, and increased production during the year ended December 31, 2018. On a per unit

Table of Contents

basis, depletion expense decreased $0.54 per Boe, or 2.5%, to $20.94 per Boe for the year ended December 31, 2018 as compared to $21.48 per Boe for the year ended December 31, 2017 due to the year-over-year increase in production and the higher production per unit of capital spending in the Merge area.

Impairment of oil and gas properties. Impairment charges of $1,332.0 million were recognized during the year ended December 31, 2018, as compared to $149.6 million for the year ended December 31, 2017. Primarily due to our liquidity position, we recognized impairment charges of $261.0 million and $1,060.0 million to our proved oil and gas properties in the Eastern Anadarko Basin and Western Anadarko Basin, respectively and an impairment charge of $11.0 million to our unproved oil and gas properties in the Western Anadarko Basin. See Note 9, "Fair Value Measurement," in the Notes to Consolidated Financial Statements for further information regarding 2018 impairment charges. During the second quarter of 2017, as a result of the Arkoma Divestiture, the Company recognized an impairment charge of $148.0 million based on the Company's negotiated sale price of the Arkoma Basin oil and gas property assets and related liabilities. Additionally, the Company recognized an impairment charge of $1.6 million during the fourth quarter of 2017 related to minor properties, which we are not currently developing.

General and administrative. General and administrative expenses increased by $1.3 million, or 4.3%, to $31.2 million for the year ended December 31, 2018, as compared to $29.9 million for the year ended December 31, 2017. The increase was driven by professional and support service costs, offset by a reduction in non-cash compensation expense. Cash paid for general and administrative expenses increased by $7.8 million, or 36.0%, to $29.1 million for the year ended December 31, 2018, as compared to $21.4 million for the year ended December 31, 2017. The increase in cash paid for general and administrative expenses is primarily related to the Company's on-going liability management efforts during the year ended December 31, 2018. Non-cash compensation expense decreased $5.0 million from $6.5 million for the year ended December 31, 2017 to $1.4 million for the year ended December 31, 2018, due to changes in the compensation structure. On a per unit basis, general and administrative expenses, excluding non-cash items, increased from $2.75 per Boe for the year ended December 31, 2017 to $3.51 per Boe for the year ended December 31, 2018.

Interest expense. Interest expense increased by $37.6 million, or 72.7%, to $89.3 million for the year ended December 31, 2018, as compared to $51.7 million for the year ended December 31, 2017. The increase was driven by the issuance of the 2023 First Lien Notes on February 14, 2018. Additionally, the Company recognized accelerated amortization of debt issuance costs of $3.8 million during the year ended December 31, 2018 associated with the modification of the Revolver due to the issuance of the 2023 First Lien Notes. See Note 7, "Long-Term Debt," for further details. During the year ended December 31, 2018, borrowings under the Revolver, the 2022 Notes, the 2023 Notes, and the 2023 First Lien Notes bore interest at a weighted average rate of 4.46%, 6.75%, 9.25% and 9.25%, respectively. Average outstanding balances for the year ended December 31, 2018 were $74.3 million, $409.1 million, $150.0 million, and $450.0 million under the Revolver, the 2022 Notes, the 2023 Notes and the 2023 First Lien Notes, respectively.

Net gain (loss) on commodity derivatives. The net gain (loss) on commodity derivatives was a net loss of $2.8 million for the year ended December 31, 2018, as compared to a net loss of $18.0 million for the year ended December 31, 2017. The year-over-year change was driven by higher average crude oil and lower natural gas prices ($65.23 per barrel and $3.15 per Mcf, respectively) during the year ended December 31, 2018, as compared to the crude oil and natural gas prices as of December 31, 2017 ($60.46 per barrel and $3.69 per Mcf, respectively). Additionally, the Company unwound its realized 2018 and 2019 hedges resulting in recognized gains of approximately $42.8 million for the year ended December 31, 2017. No such gains were recognized during the year ended December 31, 2018.

Other income (expense). Other income (expense) for the year ended December 31, 2018 was income $53.9 million, as compared to $57.0 million for the year ended December 31, 2017. Other income (expense) during the year ended December 31, 2018 was primarily related to an increase in the TRA valuation allowance which resulted in income of

$54.9 million. Other income (expense) during the year ended December 31, 2017 primarily related to a decrease in the TRA liability as a result of the recently enacted Tax Cuts and Jobs Act, which resulted in income of $59.5 million. See Note 13, "Income Taxes," for further details on the impact of the enacted tax legislation.

Income taxes. The provision for federal and state income taxes for the year ended December 31, 2018 was a benefit of $61.8 million resulting in a 4.4% effective tax rate as a percentage of our pre-tax book income, as compared to a benefit of $50.7 million with a 22.1% effective tax rate as a percentage of our pre-tax book income for the year ended December 31, 2017. 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. For the year ended December 31, 2018, the Company recorded its provision using the 21%

federal tax rate enacted by the Tax Reform Legislation. The effective tax rate increase was primarily due to the magnitude of the effect of the valuation allowance recorded against the Company's deferred tax assets, which partially offset the tax benefit generated during the years ended December 31, 2018 and 2017. See Note 13, "Income Taxes," for further details.

Results of Operations—Year ended December 31, 2017 as compared to year ended December 31, 2016

Operating revenues

Oil and gas sales. Oil and gas sales increased $61.5 million, or 49.2%, to $186.4 million for the year ended December 31, 2017, as compared to $124.9 million for the year ended December 31, 2016. The increase was attributable to the increase in commodity prices ($40.5 million) and the increase in production volumes ($21.0 million). The increase in production volumes was driven by the year-over-year increase in producing wells due to continued drilling activity. The average realized oil price, excluding the effects of commodity derivative instruments, increased from $37.83 per Bbl to $47.46 per Bbl, or 25.5%, year over year. The average realized natural gas price, excluding the effects of commodity derivative instruments, increased from $1.67 per Mcf to $2.07 per Mcf, or 24.0%, year over year. The average realized natural gas liquids price, excluding the effects of commodity derivative instruments, increased from $13.48 per Bbl to $21.09 per Bbl, or 56.5%, year over year. Average daily production increased 11.1% to 21,332 Boe per day for the year ended December 31, 2017 as compared to 19,205 Boe per day for the year ended December 31, 2016.

Costs and expenses

Lease operating. Lease operating expense increased by $4.0 million, or 12.3%, to $36.6 million for the year ended December 31, 2017, as compared to $32.6 million for the year ended December 31, 2016. The increase in lease operating expenses is attributable to the increase in number of producing wells, primarily as a result of our continued drilling program in the Merge area. On a per unit basis, lease operating expense increased $0.07 per Boe, or 1.5%, from $4.64 per Boe in the year ended December 31, 2016 to $4.71 per Boe in the year ended December 31, 2017.

Production and ad valorem taxes. Production and ad valorem taxes decreased by $0.9 million, or 11.5%, to $6.9 million for the year ended December 31, 2017, as compared to $7.8 million for the year ended December 31, 2016. During 2017, the Company's applications for High-Cost Gas Incentive refunds and Low-Producing Gas Incentive refunds in Texas were approved for qualified wells on which taxes were initially paid between October 2012 and April 2017. The Company received net production tax refunds of $3.9 million during the year ended December 31, 2017, which were recorded as a reduction in Production and ad valorem taxes on the Company's Consolidated Statement of Operations. Production taxes, excluding the impact of these refunds, increased from $5.9 million for the year ended December 31, 2016 to $8.9 million for the year ended December 31, 2017. The increase was attributable to the increase in production volumes. 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. Offsetting, estimated ad valorem taxes decreased $0.1 million from $1.9 million for the year ended December 31, 2016 to $1.8 million for the year ended December 31, 2017. The average effective rate excluding the impact of ad valorem taxes decreased from 4.7% for the year ended December 31, 2016 to 2.7% for the year ended December 31, 2017.

Exploration. Exploration expense increased from $6.7 million for the year ended December 31, 2016 to $14.1 million for the year ended December 31, 2017. The Company recognized charges for lease abandonment of $11.0 million during 2017, as compared to $6.3 million during 2016, relating to certain leases that the Company decided during the respective year not to develop and to let lapse. Spending during 2017 primarily related to geological data and seismic processing associated with unproved acreage, focused mainly in the Eastern Anadarko Basin. No exploratory wells resulted in exploration expense during either year.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $13.3 million, or 8.6%, to $167.2 million for the year ended December 31, 2017, as compared to $153.9 million for the year ended December 31, 2016. The increase was primarily the result of capital spending related to our continued drilling program in the Merge area. On a per unit basis, depletion expense decreased $0.42 per Boe, or 1.9%, to $21.48 per Boe for the year ended December 31, 2017 as compared to $21.90 per Boe for the year ended December 31, 2016 due to the year-over-year increase in production and the higher production per unit of capital spending in the Merge area.

Impairment of oil and gas properties. Impairment charges of $149.6 million were recognized during the year ended December 31, 2017. As a result of the Arkoma Divestiture, the Company recognized an impairment charge of $148.0 million during the second quarter of 2017 based on the Company’s negotiated sale price of the Arkoma Basin oil and gas property assets and related liabilities. Additionally, the Company recognized an impairment charge of $1.6 million during the fourth quarter of 2017 related to minor properties, which we are not currently developing. No impairment charges were recognized during the year ended December 31, 2016.

General and administrative. General and administrative expenses increased by $0.3 million, or 1.0%, to $29.9 million for the year ended December 31, 2017, as compared to $29.6 million for the year ended December 31, 2016. The increase was driven by professional and support service costs, offset by a reduction in non-cash compensation expense. Non-cash compensation expense decreased $1.7 million from $8.2 million for the year ended December 31, 2016 to $6.5 million for the year ended December 31, 2017. On a per unit basis, general and administrative expenses, excluding non-cash items, decreased from $2.88 per Boe for the year ended December 31, 2016 to $2.75 per Boe for the year ended December 31, 2017.

Interest expense. Interest expense decreased by $1.4 million, or 2.6%, to $51.7 million for the year ended December 31, 2017, as compared to $53.1 million for the year ended December 31, 2016. 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, offset by an increase in borrowings under the Revolver. During the year ended December 31, 2017, borrowings under the Revolver, the 2022 Notes and the 2023 Notes bore interest at a weighted average rate of 3.04%, 6.75% and 9.25%, respectively. Average outstanding balances for the year ended December 31, 2017 were $189.0 million, $409.1 million and $150.0 million under the Revolver, the 2022 Notes and the 2023 Notes, respectively.

Net gain (loss) on commodity derivatives. The net gain (loss) on commodity derivatives was a net loss of $18.0 million for the year ended December 31, 2017, as compared to a net loss of $51.3 million for the year ended December 31, 2016. The decrease was driven by lower average crude oil and natural gas prices ($50.80 per barrel and $2.99 per Mcf, respectively) during the year ended December 31, 2017, as compared to the crude oil and natural gas prices as of December 31, 2016 ($53.75 per barrel and $3.71 per Mcf, respectively). Additionally, the Company unwound its realized 2018 and 2019 hedges resulting in recognized gains of approximately $42.8 million for the year ended December 31, 2017. See Note 8, “Derivative Instruments and Hedging Activities,” for further details.

Other income (expense). Other income (expense) for the year ended December 31, 2017 was net income of $57.0 million, as compared to net income of $0.5 million for the year ended December 31, 2016. Other income (expense) during the year ended December 31, 2017 primarily related to a decrease in the TRA liability as a result of the recently enacted Tax Cuts and Jobs Act, which resulted in income of $59.5 million. See Note 13, “Income Taxes,” for further details on the impact of the enacted tax legislation.

Income taxes. The provision for federal and state income taxes for the year ended December 31, 2017 was a benefit of $50.7 million resulting in a 22.1% effective tax rate as a percentage of our pre-tax book income, as compared to a benefit of $23.8 million with a 21.9% effective tax rate as a percentage of our pre-tax book income for the year ended December 31, 2016. 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 impact of the reduction of the maximum federal tax rate from 35% to 21% on the Company’s effective tax rate was offset by the decrease in percentage of income allocated to the non-controlling interest, subjecting a higher percentage of the Company’s net income to corporate taxes. The other significant item impacting the effective tax rate during the year ended December 31, 2017 was the IRC Section 382 limitation. See Note 13, “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 development of our assets and 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 maintain and 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 facilitate drilling on our undeveloped acreage positions and permit us to selectively expand our acreage positions. As a result of extremely challenging current market conditions and our significant indebtedness, we believe we will require a significant restructuring of our balance sheet in order to continue as a going concern in the long term. For more detailed discussion, please read "Item 1A. Risk Factors," and Note 3 "Going Concern."

Table of Contents

Our balance sheet at December 31, 2018 reflects a substantial cash position as a result of the issuance of the 2023 First Lien Notes. We intend to use this cash balance to meet future financial obligations and planned capital expenditure activities. However, we are currently operating at a net loss and we may have difficulty accessing other sources of capital, including through private and public sales of debt and equity or borrowings under credit facilities. As a result, we may be unable to generate additional cash to meet financial obligations and planned capital expenditures.

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 some or all of our planned 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 completion 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 years ended December 31, 2018, 2017 and 2016:

	Year Ended December 31,		
(in thousands of dollars)	2018	2017	2016
Net cash provided by operating activities	$ 64,108	$ 59,008	$ 25,700
Net cash used in investing activities	(240,893)	(110,004)	(130,862)
Net cash provided by / (used in) financing activities	215,777	35,826	117,911
Net increase (decrease) in cash	$ 38,992	$ (15,170)	$ 12,749

Cash Flow Provided by Operating Activities

Net cash provided by operating activities was $64.1 million for the year ended December 31, 2018 as compared to cash provided by operating activities of $59.0 million for the year ended December 31, 2017. The decrease in operating cash flows was primarily due to the $7.8 million increase in cash paid for general and administrative expenses related to the Company's on-going liability management efforts during the year ended December 31, 2018.

Net cash provided by operating activities was $59.0 million for the year ended December 31, 2017 as compared to cash provided by operating activities of $25.7 million for the year ended December 31, 2016. The increase in operating cash flows was primarily due to the $60.8 million increase in oil and gas revenues for the year ended December 31, 2017 as compared to the year ended December 31, 2016. The increase in revenue was primarily driven by the increase in commodity prices, as well as production volumes.

Our operating cash flows are sensitive to a number of variables, the most significant of which is crude oil, NGL, and natural gas prices. For additional information on the impact of changing prices on our financial position, see "Item 7A. Quantitative and Qualitative Disclosures about Market Risk."

Cash Flow Used in Investing Activities

Net cash used in investing activities was $240.9 million for the year ended December 31, 2018 as compared to cash used in investing activities of $110.0 million for the year ended December 31, 2017. The increase in investing cash used was primarily driven by cash used toward current period settlements of matured derivative contracts of $53.1

million during the year ended December 31, 2018 as compared to cash provided by current period settlements of matured derivative contracts of $72.3 million during the year ended December 31, 2017. Additionally, during the year ended December 31, 2018 there were no significant divestitures. In contrast, during the year ended December 31, 2017, the Company closed on the Arkoma Divestiture, along with sales of other non-core assets, which resulted in investing cash flows of $61.3 million.

Net cash used in investing activities was $110.0 million for the year ended December 31, 2017 as compared to cash used in investing activities of $130.9 million for the year ended December 31, 2016. The decrease in investing cash flow was primarily driven by the receipt of proceeds from the sales of non-core assets ($59.6 million increase in receipts) during 2017, as well as reduced capital spending ($19.1 million decrease) as compared to 2016. Offsetting these changes, current period settlements of matured derivative contracts declined ($60.0 million decrease in cash receipts) due to lower

Table of Contents

strike prices of maturing contracts resulting in a smaller margin between the strike price and the market price upon maturity.

We expect our 2019 capital expenditures to be approximately $60.0 million, including $48.0 million for drilling and completing wells and $12.0 million for workovers, leasing, and other capital projects. Expenditures for development and exploration of oil and gas properties are the primary use of our capital resources. Our capital budget may be adjusted as business conditions warrant. The amount, timing and allocation of capital expenditures is largely discretionary and within our control. If oil and natural gas prices decline or costs increase significantly, we could defer some or all of our budgeted capital expenditures until later periods to prioritize capital projects that we believe have the highest expected returns and potential to generate near term cash flows. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, the degree of success in drilling activities, contractual obligations, internally generated cash flows and other factors both within and outside our control.

Cash Flow Provided by Financing Activities

Net cash provided by financing activities was $215.8 million for the year ended December 31, 2018 as compared to net cash provided by financing activities of $35.8 million for the year ended December 31, 2017. The increase in financing cash flows was primarily due to the issuance of the 2023 First Lien Notes on February 14, 2018. Upon issuance, the Company received proceeds of $438.9 million. The Company used the proceeds from the offering toward net repayments under the Revolver of $211.0 million. On June 27, 2018, all outstanding borrowings under the Revolver were repaid in full.

Net cash provided by financing activities was $35.8 million for the year ended December 31, 2017 as compared to net cash provided by financing activities of $117.9 million for the year ended December 31, 2016. The decrease in financing cash flows was primarily due to repayments under the Revolver, net of borrowings, which totaled $33.0 million during 2017 as compared to net borrowings of $68.0 million during 2016. Cash flows provided by financing activities were also impacted by net equity offerings of $8.3 million during 2017 as compared to $153.4 million during 2016. Offsetting these changes, the Company did not engage in the repurchase of our senior unsecured notes during 2017 as compared to cash used toward repurchases of $84.6 million during 2016.

Off Balance Sheet Arrangements

At December 31, 2018, we did not have any off balance sheet arrangements. See Note 17, "Commitments and Contingencies" for our future lease obligations.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2018:

	Payments Due by Period				
(dollars in thousands of dollars)	Total	Less than 1 Year	1 - 3 Years	4 - 5 Years	Thereafter
Long-term debt obligations	$ 1,009,148	$ —	$ 409,148	$ 600,000	$ —
Interest expense (1)	387,969	83,117	249,352	55,500	—
Commodity derivative obligations	369,521	369,521	—	—	—
Operating lease obligations	1,719	1,231	488	—	—
Total	$ 1,768,357	$ 453,869	$ 658,988	$ 655,500	$ —

(1) Interest expense is estimated based on the outstanding balance at December 31, 2018 multiplied by the weighted average interest rate during 2018.

Excluded from the table above are the following:

We recognize as a liability an asset retirement obligation, or ARO, associated with the retirement of a tangible long lived asset in the period in which it is incurred or becomes determinable (as defined by the standard), with an associated increase in the carrying amount of the related long lived asset. Estimating the future ARO requires management to make estimates and judgments regarding timing and existence of a liability, as well as what constitutes adequate restoration.

Table of Contents

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 such 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 each holder 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. During 2016, JEH generated taxable income, resulting in the payment during 2016 of $17.3 million in cash tax distributions to JEH unitholders (other than us). As a result of JEH's 2016 taxable income (all of which is passed-through and taxed to us and JEH's other unitholders), during 2017 we made further income tax payments to federal and state taxing authorities of $2.3 million and JEH made further tax distributions to JEH unitholders (other than us) of $0.6 million. During 2017, JEH did not generate taxable income, therefore we did not make any additional tax payments nor did JEH make any additional tax distributions other than those made as a result of 2016 JEH taxable income. Based on our 2018 operating activity and our initial 2019 operating budget and information available as of this filing, we do not anticipate that we will be required to make any additional tax payments or that JEH will make any additional tax distributions during 2019. Estimating the tax distributions required under the operating agreement is imprecise by nature, highly uncertain, and dependent upon a variety of factors.

The Company entered into the Tax Receivable Agreement with JEH and the Class B shareholders that provides for payment by Jones Energy, Inc. to exchanging Class B shareholders of 85% of the benefits, if any, that Jones Energy, Inc. is deemed to realize as a result of any exchange. As of December 31, 2018, the Company had no TRA liability, net, because the associated deferred tax assets were fully offset by the valuation allowance recorded against them and therefore, the TRA liability was reduced to zero. Estimating the timing of payments made under the Tax Receivable Agreement is imprecise by nature, highly uncertain, and dependent upon a variety of factors.

As a result of taxable income allocated from JEH in 2016, we made a payment of the TRA liability of $1.6 million during the first quarter of 2018. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Outlook," and see "Risk Factors—We will be required to make payments under the Tax Receivable Agreement for certain tax benefits we may receive (or be deemed to receive), and the amounts of such payments could be significant." for further discussion of these items.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based on our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States, or GAAP. As used herein, the following acronyms have the following meanings: "FASB" means the Financial Accounting Standards Board; the "Codification" refers to the Accounting Standards Codification, the collected accounting and reporting guidance maintained by the FASB; "ASC" means Accounting Standards Codification and is generally followed by a number indicating a particular section of the Codification; and "ASU" means Accounting Standards Update, followed by an identification number, which are the periodic updates made to the Codification by the FASB.

The preparation of our consolidated financial statements requires us to make estimates and assumptions that affect our reported results of operations and the amount of reported assets, liabilities and proved oil and natural gas reserves. Some accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions or if different assumptions had been used. Actual results may differ from the estimates and assumptions used in the preparation of our consolidated financial statements. Described below are the most significant policies we apply in preparing our consolidated financial statements, some of which are subject to alternative treatments under GAAP. We also describe the most significant estimates and assumptions we make in applying these policies.

Reserves. Reserve estimates significantly impact depreciation and depletion expense and the calculation of potential impairments of oil and gas properties. Under the SEC rules, proved reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations. The term “reasonable certainty” implies a high degree of confidence that the quantities of oil and natural gas actually recovered will equal or exceed the estimate. Reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

Probable reserves are those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates.

Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates.

Reserves were calculated using an unweighted arithmetic average of commodity prices in effect on the first day of each month within the twelve month period ending on the date as of which the applicable estimate is presented. These prices were adjusted for quality, transportation fees, geographical differentials, marketing bonuses or deductions and other factors affecting the price received at the wellhead.

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.

Property and Equipment. Oil and gas producing activities are accounted for using the successful efforts method of accounting. Under the successful efforts method, lease acquisition costs and all development costs, including unsuccessful development wells, are capitalized.

Impairment—The capitalized costs of proved oil and gas properties are reviewed at least annually for impairment, whenever events or changes in circumstances indicate that the carrying amount of a long lived asset or asset group exceeds its fair market value and is not recoverable. The determination of recoverability is based on comparing the estimated undiscounted future net cash flows from a producing field to the carrying value of the assets. If the future undiscounted cash flows, based on estimates of anticipated production and future oil and natural gas prices and operating costs, are lower than the carrying cost, the carrying cost of the field assets is reduced to fair value. For our proved oil and gas properties, we estimate fair value by discounting the projected future cash flows at an appropriate risk adjusted discount rate.

Table of Contents

Unproved leasehold costs are assessed at least annually to determine whether they have been impaired based upon lease terminations, expected drilling plans, and the impact of any unsuccessful exploratory drilling. Individually significant properties are assessed for impairment on a property by property basis, while individually insignificant unproved leasehold costs may be assessed in the aggregate. If unproved leasehold costs are found to be impaired, an impairment allowance is provided and a loss is recognized in the statement of operations.

Sales—Sales of significant portions of a proved field are charged to income as incurred. Gain or loss on the sale is recognized to the extent of the difference between the net proceeds received and the remaining carrying value of the properties sold. Proceeds from the sale of insignificant portions of a larger proved field are accounted for as a recovery of costs, thereby reducing the carrying value of the field until such value reaches zero. For sales of entire working interests in unproved properties, gain or loss is recognized to the extent of the difference between the proceeds received and the net carrying value of the property. Proceeds from sales of partial interests in unproved properties are accounted for as a recovery of costs unless the proceeds exceed the entire cost of the property.

Derivative Financial Instruments. We use derivative contracts to hedge the effects of fluctuations in the prices of oil, natural gas and NGLs. We record such derivative instruments as assets or liabilities in the balance sheet (see Note 9, "Fair Value Measurement," in the Notes to Consolidated Financial Statements for further information on fair value). Estimating the fair value of derivative financial instruments requires management to make estimates and judgments regarding volatility and counterparty credit risk. We use net presentation of derivative assets and liabilities when such assets and liabilities are with the same counterparty and allowed under the ISDA trading agreement with such counterparty.

We have not designated any of our derivative contracts as fair value or cash flow hedges. The changes in fair value of the contracts are included in net income in the period of the change as "Net gain (loss) on commodity derivatives."

Share Based Compensation. We measure and record compensation expense for all share based payment awards to employees and directors based on estimated grant date fair values. Compensation costs for share based awards are recognized over the requisite service period based on the grant date fair value. Prior to our IPO, we were not publicly traded, and did not have a listed price with which to calculate fair value. We have historically and consistently calculated fair value using combined valuation models including an enterprise valuation approach; an income approach, utilizing future discounted and undiscounted cash flows; and a market approach, taking into consideration peer group analysis of publicly traded companies, and when available, actual cash transactions in our common stock.

Acquisitions. Acquisitions are accounted for as purchases and, accordingly, the results of operations are included in our statement of operations from the closing date of the acquisition. Purchase prices are allocated to acquired assets and assumed liabilities, if any, based on their estimated fair value at the time of the acquisition. We have historically and consistently calculated fair value using combined valuation models including an enterprise valuation approach; an income approach, utilizing future discounted and undiscounted cash flows; and a market approach, taking into consideration peer group analysis of publicly traded companies.

Asset Retirement Obligations. We recognize as a liability an asset retirement obligation, or ARO, associated with the retirement of a tangible long lived asset in the period in which it is incurred or becomes determinable (as defined by the standard), with an associated increase in the carrying amount of the related long lived asset. The cost of the tangible asset, including the initially recognized asset retirement cost, is depreciated over the useful life of the asset and accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. We measure the fair value of the ARO using expected future cash outflows for abandonment discounted generally at our cost of capital at the time of recognition.

Estimating the future ARO requires management to make estimates and judgments regarding timing and existence of a liability, as well as what constitutes adequate restoration. Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

Table of Contents

Liability under Tax Receivable Agreement. In connection with the IPO, the Company entered into a Tax Receivable Agreement (the "TRA") which obligates the Company to make payments to certain current and former owners equal to 85% of the applicable cash savings that the Company realizes as a result of tax attributes arising from exchanges of JEH Units and shares of the Company's Class B common stock held by those owners for shares of the Company's Class A common stock. The Company will retain the benefit of the remaining 15% of these tax savings.

As a result of exchanges made, the Company accrues the estimated future tax benefits and accounts for this estimated amount as a reduction of deferred tax liabilities on its consolidated balance sheet. The actual amount and timing of payments to be made under the TRA will depend upon a number of factors, including the amount and timing of taxable income generated in the future, changes in future tax rates, the use of loss carryovers, and the portion of the Company's payments under the TRA constituting imputed interest. 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.

Recent Accounting Pronouncements

See Note 2, "Significant Accounting Policies—Recent Accounting Pronouncements" in our Notes to the Consolidated Financial Statements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

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

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

Commodity price risk and hedges

Our principal market risk exposure is to oil, natural gas and NGL prices, which are inherently volatile. As such, future earnings are subject to change due to fluctuations in such prices. Realized prices are primarily driven by the prevailing prices for oil and regional spot prices for natural gas and NGLs. We have used, and expect to continue to use, oil, natural gas and NGL derivative contracts to reduce our risk of price fluctuations of these commodities. Pursuant to our risk management policy, we engage in these activities as a hedging mechanism against price volatility associated with projected production levels. The fair value of our oil, natural gas and NGL derivative contracts at December 31, 2018 was a net asset of $6.0 million.

For the years ending December 31, 2019, 2020, and 2021, approximately 62%, 33%, and 0%, respectively, of our estimated total oil, natural gas and NGL production from proved reserves, based on our reserve report as of December 31, 2018, are hedged by commodity derivative contracts, respectively. For information regarding the terms of these hedges, please see "—Basis of presentation—Hedging" above. The production hedged thereby is consistent with the assumed drilling schedule and monthly production levels in the December 31, 2018 reserve report prepared by Cawley Gillespie, which is based on prices, costs and other assumptions required by SEC rules. Our actual production will vary from the amounts estimated in this reserve report, perhaps materially. Please read "Risk factors—Our estimated oil and natural gas reserve quantities and future production rates are based on many assumptions that may prove to be inaccurate. Any material inaccuracies in these reserve estimates or the underlying assumptions will materially affect the quantities and present value of our reserves."

Counterparty and customer credit risk

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

While we do not typically require our partners, customers and counterparties to post collateral, we have begun to make cash calls to our partners for their share of future project expenditures. We periodically review, evaluate and assess the

Table of Contents

credit standing of our partners or customers for oil and gas receivables and the counterparties on our derivative instruments. This evaluation may include reviewing a party's credit rating, latest financial information and, in the case of a customer with which we have receivables, their historical payment record, and undertaking the due diligence necessary to determine creditworthiness. The counterparties on our derivative instruments currently in place are lenders under the revolving credit facility with investment grade ratings.

Item 8. Financial Statements and Supplementary Data

Our consolidated financial statements and supplementary financial data are included in this Annual Report beginning on page F 1.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Item 9A. Controls and Procedures

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.

Our management, with the participation of our principal executive officer and principal financial officer, evaluated the effectiveness of the design and operation of our disclosure controls and procedures. Based on that evaluation, our principal executive officer and principal financial officer concluded that as of December 31, 2018, the end of the period covered by this report, our disclosure controls and procedures are effective at a reasonable assurance level.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a 15(f) and Rule 15d 15(f) under the Exchange Act). Our internal control over financial reporting is a process designed under the supervision of our principal executive officer and principal financial officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of our financial statements for external purposes in accordance with generally accepted accounting principles.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

As of December 31, 2018, our management assessed the effectiveness of our internal control over financial reporting based on the criteria for effective internal control over financial reporting established by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in Internal Control—Integrated Framework (2013). Management's assessment included an evaluation of the design of our internal control over financial reporting and testing of the operational effectiveness of our internal control over financial reporting. Based on this assessment, management has concluded that, as of December 31, 2018, the Company's internal control over financial reporting is effective based on those criteria.

Attestation Report of the Registered Public Accounting Firm

This annual report does not include an attestation report of the company's registered public accounting firm regarding internal control over financial reporting. Management's report was not subject to attestation by the company's registered

Table of Contents

public accounting firm pursuant to rules of the Securities and Exchange Commission that permit the company to provide only management's report in this annual report.

Changes in Internal Control over Financial Reporting

There have been no changes in internal control over financial reporting during the quarter ended December 31, 2018 that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting.

Item 9B. Other Information

None.

Table of Contents

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information called for by this Item 10 is incorporated herein by reference to the definitive Proxy Statement to be filed by the registrant pursuant to Regulation 14A of the General Rules and Regulations under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10 K.

Item 11. Executive Compensation

The information called for by this Item 11 is incorporated herein by reference to the definitive Proxy Statement to be filed by the registrant pursuant to Regulation 14A of the General Rules and Regulations under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10 K.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information called for by this Item 12 is incorporated herein by reference to the definitive Proxy Statement to be filed by the registrant pursuant to Regulation 14A of the General Rules and Regulations under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10 K.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information called for by this Item 13 is incorporated herein by reference to the definitive Proxy Statement to be filed by the registrant pursuant to Regulation 14A of the General Rules and Regulations under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10 K.

Item 14. Principal Accounting Fees and Services

The information called for by this Item 14 is incorporated herein by reference to the definitive Proxy Statement to be filed by the registrant pursuant to Regulation 14A of the General Rules and Regulations under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10 K.

Table of Contents

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a)The following documents are filed as part of this report or incorporated by reference:

(1) Financial Statements. Our consolidated financial statements are included under Part II, Item 8 of this Annual Report. For a listing of these statements and accompanying footnotes, see “Index to Consolidated Financial Statements” on page F 1 of this Annual Report.

(2) Financial Statement Schedules. All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated financial statements or notes thereto.

(3) Exhibits. The exhibits required to be filed by this Item 15 are set forth in the Exhibit Index accompanying this Annual Report on Form 10 K.

EXHIBIT INDEX

Exhibit No.	Description
3.1	Amended and Restated Certificate of Incorporation of Jones Energy, Inc. (incorporated by reference to Exhibit 3.1 to the Company’s Current Report on Form 8-K filed with the Securities and Exchange Commission on July 30, 2013).
3.2	Amended and Restated Bylaws of Jones Energy, Inc. (incorporated by reference to Exhibit 3.2 to the Company’s Current Report on Form 8-K filed with the Securities and Exchange Commission on July 30, 2013).
3.3	Certificate of Designations of the 8.0% Series A Perpetual Convertible Preferred Stock, filed with the Secretary of State of the State of Delaware and effective August 25, 2016 (including form of stock certificate) (incorporated by reference herein to the Company’s Current Report on Form 8-K filed with the Securities and Exchange Commission on August 26, 2016).
3.4	Amendment to the Amended and Restated Certificate of Incorporation of Jones Energy, Inc., effective September 7, 2018 (incorporated by reference to Exhibit 3.1 to the Company’s Current Report on Form 8-K filed with the Securities and Exchange Commission on September 10, 2018).
3.5	Certificate of Correction to Certificate of Amendment to the Amended and Restated Certificate of Incorporation of Jones Energy, Inc., effective September 7, 2018 (incorporated by reference to Exhibit 3.2 to the Company’s Current Report on Form 8-K filed with the Securities and Exchange Commission on September 10, 2018).
4.1	Form of Class A common stock Certificate (incorporated by reference to Exhibit 4.2 to the Company’s Registration Statement on Form S-1, File No. 333-188896, filed with the Securities and Exchange Commission on June 7, 2013).
4.2	Amended and Restated Registration Rights and Stockholders Agreement, dated May 2, 2017, among Jones Energy, Inc., Jones Energy Holdings, LLC and the other parties thereto (incorporated by reference to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 5, 2017).
4.3	Indenture, dated April 1, 2014, among Jones Energy Holdings, LLC, Jones Energy Finance Corp., the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Company’s Current Report on Form 8 K filed with the Securities and

	Exchange Commission on April 1, 2014).
4.4	Registration Rights Agreement, dated April 1, 2014, among Jones Energy Holdings, LLC, Jones Energy Finance Corp., the Guarantors named therein and Citigroup Global Markets Inc., as the sole representative of the Initial Purchasers named therein (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8 K filed with the Securities and Exchange Commission on April 1, 2014).

Table of Contents

Exhibit No.	Description
4.5	Indenture, dated February 23, 2015, among Jones Energy Holdings, LLC, Jones Energy Finance Corp., the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Jones Energy, Inc.'s Current Report on Form 8 K filed with the Securities and Exchange Commission on February 27, 2015).
4.6	Registration Rights Agreement dated February 23, 2015, among Jones Energy Holdings, LLC, Jones Energy Finance Corp., the Guarantors named therein and the purchasers named therein (incorporated by reference to Exhibit 4.2 to Jones Energy, Inc.'s Current Report on Form 8 K filed with the Securities and Exchange Commission on February 27, 2015).
4.7	Form of certificate for the 8.0% Series A Perpetual Convertible Preferred Stock (included as Exhibit A to Exhibit 3.3)
4.8	Indenture, dated as of February 14, 2018, among Jones Energy Holdings, LLC, Jones Energy Finance Corp., the Guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8 K filed with the Securities and Exchange Commission on February 16, 2018).
4.9	Indenture, dated as of February 14, 2018, by and among Jones Energy Holdings, LLC, Jones Energy Finance Corp., Jones Energy, Inc., each of the Subsidiary Guarantors (as defined therein), UMB Bank, N.A., and Wells Fargo Bank, National Association (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on February 16, 2018).
4.10	First Supplemental Indenture, dated as of April 20, 2018, among Nosley Midstream, LLC, Jones Energy Holdings, LLC, Jones Energy Finance Corp., UMB Bank, N.A., and Wells Fargo Bank, National Association (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 10-Q filed with the Securities and Exchange Commission on May 4, 2018).
10.1	Fourth Amended and Restated Limited Liability Company Agreement of Jones Energy Holdings, LLC, dated as of August 25, 2016 (incorporated by reference herein to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on August 26, 2016)
10.2	Amendment No. 1 to Fourth Amended and Restated Limited Liability Company Agreement of Jones Energy Holdings, LLC, dated as of September 30, 2016 (incorporated by reference herein to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on October 6, 2016)
10.3	Exchange Agreement, dated as of July 29, 2013, by and among Jones Energy, Inc., Jones Energy Holdings, LLC and the members of Jones Energy Holdings, LLC party thereto (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on July 30, 2013).
10.4	Tax Receivable Agreement, dated as of July 29, 2013, by and among Jones Energy, Inc., Jones Energy Holdings, LLC and the members of Jones Energy Holdings, LLC party thereto (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on July 30, 2013).
10.5 †	Amended and Restated Jones Energy, Inc. 2013 Omnibus Incentive Plan, effective as of May 4, 2016 (incorporated by reference to Appendix A to the Company's Definitive Proxy Statement on Schedule 14A filed with the Securities and Exchange Commission on March 30, 2016).
10.6 †	Amended and Restated Jones Energy, Inc. Short Term Incentive Plan, effective as of May 4, 2016 (incorporated by reference to Appendix B to the Company's Definitive Proxy Statement on Schedule 14A filed with the Securities and Exchange Commission on March 30, 2016).
10.7 †	Form of Director Restricted Stock Award Agreement (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on September 4, 2013).

10.8 †	Form of Employee Restricted Stock Award Agreement (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on May 27, 2014).

Exhibit No.	Description
10.9 †	Form of Performance Share Unit Award Agreement (formerly referred to as a Performance Unit Award) (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on May 27, 2014).
10.10 †	Jones Energy, LLC Executive Deferral Plan (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on October 23, 2013).
10.11 †	Jones Energy Holdings, LLC Monarch Equity Plan (incorporated by reference to Exhibit 10.8 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on May 28, 2013).
10.12	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.5 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed with the Securities and Exchange Commission on June 7, 2013).
10.13	Credit Agreement, dated as of December 31, 2009, among Jones Energy Holdings, LLC, as borrower, Wells Fargo Bank N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.9 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed with the Securities and Exchange Commission on May 28, 2013).
10.14	Agreement and Amendment No. 1 to Credit Agreement (First Lien) (incorporated by reference to Exhibit 10.10 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed with the Securities and Exchange Commission on May 28, 2013).
10.15	Master Assignment, Agreement and Amendment No. 2 to Credit Agreement (incorporated by reference to Exhibit 10.11 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed with the Securities and Exchange Commission on May 28, 2013).
10.16	Master Assignment, Agreement and Amendment No. 3 to Credit Agreement (incorporated by reference to Exhibit 10.12 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed with the Securities and Exchange Commission on May 28, 2013).
10.17	Agreement and Amendment No. 4 to Credit Agreement (First Lien) (incorporated by reference to Exhibit 10.13 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed with the Securities and Exchange Commission on May 28, 2013).
10.18	Master Assignment, Agreement and Amendment No. 5 to Credit Agreement (incorporated by reference to Exhibit 10.14 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed with the Securities and Exchange Commission on May 28, 2013).
10.19	Waiver and Amendment No. 6 to Credit Agreement (incorporated by reference to Exhibit 10.15 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed with the Securities and Exchange Commission on May 28, 2013).
10.20	Waiver, Agreement and Amendment No. 7 to Credit Agreement and Amendment to Guarantee and Collateral Agreement (incorporated by reference to Exhibit 10.24 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed with the Securities and Exchange Commission on June 17, 2013).
10.21	Borrowing Base Increase Agreement, dated as of December 18, 2013, among Jones Energy Holdings, LLC, as borrower, certain subsidiaries of Jones Energy Holdings, LLC, as guarantors, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.19 to the Company's Annual Report on Form 10-K filed with the Securities and Exchange Commission on March 14, 2014).
10.22	Agreement and Amendment No. 8 to Credit Agreement dated as of January 29, 2014, among Jones Energy Holdings, LLC, as borrower, Jones Energy, Inc., Jones Energy, LLC and Nosley Assets, LLC, as guarantors, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.20 to the Company's Annual Report on Form 10-K filed with the Securities and Exchange Commission on March 14, 2014).

Table of Contents

Exhibit No.	Description
10.23	Master Assignment, Agreement and Amendment No. 9 to Credit Agreement dated as of November 6, 2014, among Jones Energy Holdings, LLC, as borrower, Jones Energy, Inc., Jones Energy, LLC and Nosley Assets, LLC, as guarantors, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.22 to the Company's Annual Report on Form 10-K for the year ended December 31, 2015 filed with the Securities and Exchange Commission on March 9, 2016).
10.24	Amendment No. 10 to Credit Agreement dated as of August 1, 2016, among Jones Energy Holdings, LLC, as borrower, Jones Energy, Inc., Jones Energy, LLC and Nosley Assets, LLC, as guarantors, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2016 filed with the Securities and Exchange Commission on November 4, 2016).
10.25	Guarantee and Collateral Agreement, dated as of January 29, 2014, between Jones Energy, Inc., as guarantor, and Wells Fargo Bank, N.A., as administrative agent (incorporated by reference to Exhibit 10.21 to the Company's Annual Report on Form 10-K filed on March 14, 2014).
10.26	Amended and Restated Firm Crude Oil Gathering and Transportation Agreement, dated October 23, 2015, by and between Monarch Oil Pipeline, LLC and Jones Energy, LLC (incorporated by reference to Exhibit 10.34 to the Company's Annual Report on Form 10-K filed on March 9, 2016).
10.27	Amended and Restated Gathering and Transportation Services Agreement, dated as of October 23, 2015, by and between Monarch Oil Pipeline, LLC and Jones Energy, LLC (incorporated by reference to Exhibit 10.35 to the Company's Annual Report on Form 10-K filed on March 9, 2016).
10.28	Amendment No. 11 to Credit Agreement dated as of November 26, 2017, among Jones Energy Holdings, LLC, as borrower, Jones Energy, Inc., Jones Energy, LLC and Nosley Assets, LLC, as guarantors, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on November 27, 2017).
10.29†	Form of Restricted Stock Unit Award Agreement (incorporated by reference to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 5, 2017).
10.30†	Form of Performance Share Unit Award Agreement (incorporated by reference to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 5, 2017).
10.31†	Form of Performance Unit Award Agreement (incorporated by reference to the Quarterly Report on Form 10-Q filed with the Securities and Exchange Commission on May 5, 2017).
10.32†	Notice to Performance Award Holders (incorporated by reference to Exhibit 99.2 to the Company's Current Report on Form 8-K filed on February 6, 2018).
10.33	Amended and Restated Collateral Agreement, dated as of February 14, 2018, made by each of the Grantors (as defined therein) in favor of Wells Fargo Bank, National Association (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8 K filed with the Securities and Exchange Commission on February 16, 2018).
10.34	Amended and Restated Collateral Agreement, dated as of February 14, 2018, made by Jones Energy, Inc. in favor of Wells Fargo Bank, National Association (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on February 16, 2018).
10.35	Amendment No. 12 to Credit Agreement, dated as of February 14, 2018, among Jones Energy Holdings, LLC, as borrower, Jones Energy, Inc., Jones Energy, LLC and Nosley Assets, LLC, Nosley SCOOP, LLC, Nosley Acquisition, LLC and Jones Energy Finance Corp., as guarantors, Wells Fargo Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.3 to the Company's Current Report on Form 8-K filed on February 16, 2018).
10.39	Amendment No. 13 to Credit Agreement dated as of June 28, 2018, among Jones Energy Holdings, LLC, as borrower, Jones Energy, Inc., Jones Energy, LLC, Nosley Assets, LLC, Nosley SCOOP, LLC, Nosley Acquisition, LLC, Jones Energy Finance Corp. and Nosley Midstream, LLC as guarantors, Wells Fargo

Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on July 2, 2018).

Table of Contents

Exhibit No.	Description
10.40	Amended and Restated Employment Agreement, dated September 24, 2018 and effective July 12, 2018, between Jones Energy, LLC and Carl F. Giesler, Jr. (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2018 filed with the Securities and Exchange Commission on November 2, 2018).
10.41	Form of Cash Award Agreement (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q for the quarterly period ended September 30, 2018 filed with the Securities and Exchange Commission on November 2, 2018).
10.42	Form of Severance Agreement (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on January 14, 2019).
10.43	Second Amended and Restated Employment Agreement, dated January 14, 2019 and effective December 12, 2018, between Jones Energy, LLC and Carl F. Giesler, Jr. (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on January 14, 2019).
10.44	Termination Amendment to Jones Energy, LLC Executive Deferral Plan (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the Securities and Exchange Commission on January 31, 2019).
21.1*	List of Subsidiaries of Jones Energy, Inc.
23.1*	Consent of Grant Thornton LLP.
23.2*	Consent of PricewaterhouseCoopers LLP.
23.3*	Consent of Cawley Gillespie & Associates, Inc.
31.1*	Rule 13a 14(a)/15d 14(a) Certification of Carl F. Giesler (Principal Executive Officer).
31.2*	Rule 13a 14(a)/15d 14(a) Certification of Thomas Hester (Principal Financial Officer).
32.1**	Section 1350 Certification of Carl F. Giesler (Principal Executive Officer).
32.2**	Section 1350 Certification of Thomas Hester (Principal Financial Officer).
99.1*	Summary Report of Cawley, Gillespie & Associates, Inc. for reserves as of December 31, 2018.
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

†—Management contract or compensatory plan or arrangement required to be filed as an exhibit to this 10 K pursuant to Item 15(b).

Item 16. Form 10-K Summary

None.

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) 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: February 28, 2019 By: /s/ Carl F. Giesler, Jr.
Name: Carl F. Giesler, Jr.
Title: Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Name	Title	Date
/s/ Jonny Jones Jonny Jones	Chairman of the Board of Directors	February 28, 2019
/s/ Carl F. Giesler, Jr. Carl F. Giesler, Jr.	Director and Chief Executive Officer (Principal Executive Officer)	February 28, 2019
/s/ Thomas Hester Thomas Hester	Senior Vice President and Chief Financial Officer (Principal Accounting and Financial Officer)	February 28, 2019
/s/ Alan D. Bell Alan D. Bell	Director	February 28, 2019
/s/ Halbert S. Washburn Halbert S. Washburn	Director	February 28, 2019
/s/ Stephen Jones Stephen Jones	Director	February 28, 2019
/s/ Tara W. Lewis Tara W. Lewis	Director	February 28, 2019
/s/ L. Spencer Wells L. Spencer Wells	Director	February 28, 2019

Table of Contents

GLOSSARY OF OIL AND NATURAL GAS TERMS

The terms and abbreviations defined in this section are used throughout this Annual Report on Form 10K:

“AMI”—Area of mutual interest, typically referring to a contractually defined area under a joint development agreement whereby parties are subject to mutual participatory rights and restrictions.

“Basin”—A large natural depression on the earth’s surface in which sediments generally brought by water accumulate.

“Bbl”—One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate or NGLs.

“Bench” – a subsection or zone of a reservoir that can be grouped separately i.e. an upper, middle, or lower zone.

“Boe”—Barrels of oil equivalent, with 6,000 cubic feet of natural gas being equivalent to one barrel of oil.

“Boe/d”—Barrels of oil equivalent per day.

“British thermal unit (BTU)”—The heat required to raise the temperature of one pound of water by one degree Fahrenheit.

“Completion”—The process of treating a drilled well followed by the installation of permanent equipment for the production of oil or natural gas, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

“Condensate”—A mixture of hydrocarbons that exists in the gaseous phase at original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

“Developed acreage”—The number of acres that are allocated or assignable to productive wells or wells capable of production.

“Developed reserves”—Reserves of any category that can be expected to be recovered (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

“Development well”—A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

“Dry hole”—A well found to be incapable of producing hydrocarbons in sufficient quantities to justify completion of the well, such that proceeds from the sale of such production do not exceed production expenses and taxes.

“Economically producible”—A resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

“Exploratory well”—A well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil.

“Farm in or farm out”—An agreement under which the owner of a working interest in an oil or natural gas lease assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interests received by an assignee is a “farm in” while the interest transferred by the assignor is a “farm out.”

“Field”—An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition.

“Formation”—A layer of rock which has distinct characteristics that differ from nearby rock.

Table of Contents

“Fracture stimulation”—A process whereby fluids mixed with proppants are injected into a wellbore under pressure in order to fracture, or crack open, reservoir rock, thereby allowing oil and/or natural gas trapped in the reservoir rock to travel through the fractures and into the well for production.

“Gross acres or gross wells”—The total acres or well, as the case may be, in which a working interest is owned.

“Horizontal drilling”—A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

“Joint development agreement”—Includes joint venture agreements, farm in and farm out agreements, joint operating agreements and similar partnering arrangements.

“MBbl”—One thousand barrels of oil, condensate or NGLs.

“MBoe”—One thousand barrels of oil equivalent, determined using the equivalent of six Mcf of natural gas to one Bbl of crude oil.

“Mcf”—One thousand cubic feet of natural gas.

“MMBoe”—One million barrels of oil equivalent.

“MMBtu”—One million British thermal units.

“MMcf”—One million cubic feet of natural gas.

“Net acres or net wells”—The sum of the fractional working interest owned in gross acres or gross wells. An owner who has 50% interest in 100 acres owns 50 net acres.

“Net revenue interest”—An owner’s interest in the revenues of a well after deducting proceeds allocated to royalty and overriding interests.

“Possible reserves”—Additional reserves that are less certain to be recognized than probable reserves.

“Probable reserves”—Additional reserves that are less certain to be recovered than proved reserves but which, in sum with proved reserves, are as likely as not to be recovered.

“Productive well”—A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

“Prospect”—A specific geographic area which, based on supporting geological, geophysical or other data and also preliminary economic analysis using reasonably anticipated prices and costs, is considered to have potential for the discovery of commercial hydrocarbons.

“Proved developed non producing”—Hydrocarbons in a potentially producing horizon penetrated by a wellbore, the production of which has been postponed pending installation of surface equipment or gathering facilities, or pending the production of hydrocarbons from another formation penetrated by the wellbore. The hydrocarbons are classified as proved but non producing reserves.

"Proved developed reserves"—Proved reserves that can be expected to be recovered through existing wells and facilities and by existing operating methods.

"Proved reserves"—Reserves of oil and natural gas that have been proved to a high degree of certainty by analysis of the producing history of a reservoir and/or by volumetric analysis of adequate geological and engineering data to be economically producible.

"Proved undeveloped reserves (PUD)"—Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

"Recompletion"—The process of re entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

Table of Contents

“Reserves”—Estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible as of a given date by application of development projects to known accumulations.

“Reservoir”—A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

“Royalty interest”—An interest in an oil and natural gas property entitling the owner to a share of oil or gas production free of production costs.

“Spacing”—The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40 acre spacing, and is often established by regulatory agencies.

“Spud”—The commencement of drilling operations of a new well.

“Standardized measure of discounted future net cash flows”—The present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with the regulations of the Securities and Exchange Commission, without giving effect to non property related expenses such as general and administrative expenses, debt service, future income tax expenses or depreciation, depletion and amortization; discounted using an annual discount rate of 10%.

“Trend”—A region of oil and/or natural gas production, the geographic limits of which have not been fully defined, having geological characteristics that have been ascertained through supporting geological, geophysical or other data to contain the potential for oil and/or natural gas reserves in a particular formation or series of formations.

“Unconventional formation”—A term used in the oil and natural gas industry to refer to a formation in which the targeted reservoirs generally fall into one of three categories: (1) tight sands, (2) coal beds, or (3) oil and gas shales. The reservoirs tend to cover large areas and lack the readily apparent traps, seals and discrete hydrocarbon water boundaries that typically define conventional reservoirs. These reservoirs generally require fracture stimulation treatments or other special recovery processes in order to produce economic flow rates.

“Undeveloped acreage”—Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether such acreage contains proved reserves.

“Wellbore”—The hole drilled by the bit that is equipped for oil or gas production on a completed well. Also called well or borehole.

“Working interest”—The right granted to the lessee of a property to explore for and to produce and own oil, gas, or other minerals and receive a share of the production. The working interest owners bear the exploration, development, and operating costs of the property.

Table of Contents

Index to Financial Statements

Reports of Independent Registered Public Accounting Firms	F 2
Consolidated Financial Statements	
Balance Sheets	F 4
Statements of Operations	F 5
Statement of Changes in Stockholders' Equity	F 6
Statements of Cash Flows	F 7
Notes to the Consolidated Financial Statements	F 8
Supplemental Information on Oil and Gas Producing Activities (Unaudited)	F 57
Supplemental Quarterly Financial Information (Unaudited)	F 61

Table of Contents

Report of Independent Registered Public Accounting Firm

Board of Directors and Stockholders

Jones Energy, Inc.

Opinion on the financial statements

We have audited the accompanying consolidated balance sheet of Jones Energy, Inc. (a Delaware corporation) and subsidiaries (the “Company”) as of December 31, 2018, the related consolidated statements of operations, changes in stockholders’ equity, and cash flows for the year ended December 31, 2018, and the related notes (collectively referred to as the “financial statements”). In our opinion, the financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018, and the results of its operations and its cash flows for the year ended December 31, 2018, in conformity with accounting principles generally accepted in the United States of America.

Going concern

The accompanying financial statements have been prepared assuming that the Company will continue as a going concern. As discussed in Note 3 to the financial statements, the Company has substantial debt obligations requiring significant interest payments. The ongoing capital and operating expenditures, including the debt interest payments, will vastly exceed the amount of cash on hand and the revenue they expect to generate from operations in the near future. These conditions, along with other matters as set forth in Note 3, raise substantial doubt about the Company’s ability to continue as a going concern. Management’s plans in regard to these matters are also described in Note 3. The financial statements do not include any adjustments that might result from the outcome of this uncertainty.

Basis for opinion

These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on the Company’s financial statements based on our audit. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (“PCAOB”) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement, whether due to error or fraud. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. As part of our audit we are required to obtain an understanding of internal control over financial reporting but not for the purpose of expressing an opinion on the effectiveness of the Company’s internal control over financial reporting. Accordingly, we express no such opinion.

Our audit included performing procedures to assess the risks of material misstatement of the financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. Our audit also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the financial statements. We believe that our audit provides a reasonable basis for our opinion.

/s/ Grant Thornton LLP

We have served as the Company's auditor since 2018.

Houston, Texas

February 28, 2019

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of Jones Energy, Inc.:

Opinion on the Financial Statements

We have audited the consolidated balance sheet of Jones Energy, Inc. and its subsidiaries (the “Company”) as of December 31, 2017, and the related consolidated statements of operations, of changes in stockholders’ equity, and of cash flows for each of the two years in the period ended December 31, 2017, including the related notes (collectively referred to as the “consolidated financial statements”). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2017, and the results of its operations and its cash flows for each of the two years in the period ended December 31, 2017 in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on the Company’s consolidated financial statements based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits of these consolidated financial statements in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud.

Our audits included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Houston, Texas

February 28, 2018, except for the effects of the reverse stock split discussed in Note 14 to the consolidated financial statements, as to which the date is February 28, 2019

We served as the Company's auditor from 2011 to 2018.

Table of Contents

Jones Energy, Inc.

Consolidated Balance Sheets

December 31, 2018 and 2017

(in thousands of dollars)	December 31, 2018	December 31, 2017
Assets		
Current assets		
Cash and cash equivalents	$ 58,464	$ 19,472
Accounts receivable, net		
Oil and gas sales	33,954	34,492
Joint interest owners	23,997	31,651
Other	614	1,236
Commodity derivative assets	5,003	3,474
Other current assets	8,099	14,376
Total current assets	130,131	104,701
Oil and gas properties, net, under the successful efforts method	271,846	1,597,040
Other property, plant and equipment, net	1,639	2,719
Commodity derivative assets	1,415	172
Deferred tax assets	129	—
Other assets	415	5,431
Total assets	$ 405,575	$ 1,710,063
Liabilities and Stockholders' Equity		
Current liabilities		
Trade accounts payable	$ 32,506	$ 72,663
Oil and gas sales payable	34,035	31,462
Accrued liabilities	37,799	21,604
Commodity derivative liabilities	370	36,709
Other current liabilities	4,927	4,049
Total current liabilities	109,637	166,487
Long-term debt	982,157	759,316
Deferred revenue	4,118	5,457
Commodity derivative liabilities	—	8,788
Asset retirement obligations	20,432	19,652
Liability under tax receivable agreement	—	59,596
Other liabilities	495	811
Deferred tax liabilities	—	14,281
Total liabilities	1,116,839	1,034,388
Commitments and contingencies (Note 17)		
Mezzanine equity		
Series A preferred stock, $0.001 par value; 1,804,478 shares issued and outstanding at December 31, 2018 and 1,839,995 shares issued and outstanding at December 31, 2017	93,719	89,539
Stockholders' equity (1)		

Class A common stock, $0.001 par value; 5,025,632 shares issued and 5,024,491 shares outstanding at December 31, 2018 and 4,506,991 shares issued and 4,505,861 shares outstanding at December 31, 2017	5	5
Class B common stock, $0.001 par value; 172,193 shares issued and outstanding at December 31, 2018 and 481,391 shares issued and outstanding at December 31, 2017	—	—
Treasury stock, at cost: 1,141 shares at December 31, 2018 and December 31, 2017	(358)	(358)
Additional paid-in-capital	638,108	606,414
Retained (deficit) / earnings	(1,435,050)	(136,274)
Stockholders' equity	(797,295)	469,787
Non-controlling interest	(7,688)	116,349
Total stockholders’ equity	(804,983)	586,136
Total liabilities and stockholders' equity	$ 405,575	$ 1,710,063

(1) All share information presented has been recast to retrospectively adjust for the effects of the Reverse Stock Split, as defined in Note 14, “Stockholders’ and Mezzanine Equity”, effective on September 7, 2018.

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

Table of Contents

Jones Energy, Inc.

Consolidated Statements of Operations

Years Ended December 31, 2018, 2017 and 2016

	Year Ended December 31,		
(in thousands of dollars except per share data)	2018	2017	2016
Operating revenues			
Oil and gas sales	$ 236,873	$ 186,393	$ 124,877
Other revenues, net	(516)	2,180	2,970
Total operating revenues	236,357	188,573	127,847
Operating costs and expenses			
Lease operating	44,921	36,636	32,640
Production and ad valorem taxes	12,087	6,874	7,768
Transportation and processing costs	3,368	—	—
Exploration	8,157	14,145	6,673
Depletion, depreciation and amortization	173,904	167,224	153,930
Impairment of oil and gas properties	1,331,785	149,648	—
Accretion of ARO liability	1,066	960	1,263
General and administrative	31,204	29,892	29,640
Other operating	250	—	199
Total operating expenses	1,606,742	405,379	232,113
Operating income (loss)	(1,370,385)	(216,806)	(104,266)
Other income (expense)			
Interest expense	(89,328)	(51,651)	(53,127)
Gain on debt extinguishment	—	—	99,530
Net gain (loss) on commodity derivatives	(2,757)	(17,985)	(51,264)
Other income (expense)	53,935	56,952	536
Other income (expense), net	(38,150)	(12,684)	(4,325)
Income (loss) before income tax	(1,408,535)	(229,490)	(108,591)
Income tax provision (benefit)			
Current	(5)	(3,585)	3,981
Deferred	(61,836)	(47,082)	(27,767)
Total income tax provision (benefit)	(61,841)	(50,667)	(23,786)
Net income (loss)	(1,346,694)	(178,823)	(84,805)
Net income (loss) attributable to non-controlling interests	(55,655)	(77,331)	(42,253)
Net income (loss) attributable to controlling interests	$ (1,291,039)	$ (101,492)	$ (42,552)
Dividends and accretion on preferred stock	(7,737)	(7,924)	(2,669)
Net income (loss) attributable to common shareholders	$ (1,298,776)	$ (109,416)	$ (45,221)
Earnings (loss) per share (1) :			
Basic - Net income (loss) attributable to common shareholders	$ (271.94)	$ (30.22)	$ (20.79)
Diluted - Net income (loss) attributable to common shareholders	$ (271.94)	$ (30.22)	$ (20.79)

Weighted average Class A shares outstanding (1) :			
Basic	4,776	3,621	2,175
Diluted	4,776	3,621	2,175

(1) All share and earnings per share information presented has been recast to retrospectively adjust for the effects of the Special Stock Dividend distributed on March 31, 2017 and the Reverse Stock Split effective on September 7, 2018, as defined in Note 14, “Stockholders’ and Mezzanine Equity”.

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

Table of Contents

Jones Energy, Inc.

Statement of Changes in Stockholders' Equity

Years Ended December 31, 2018, 2017 and 2016

n thousands)	Common Stock Class A Shares (1)	Value	Class B Shares (1)	Value	Treasury Stock Class A Shares (1)	Value	Additional Paid-in- Capital	Retained (Deficit)/ Earnings	Non-controlling Interest	Total Stock Equit
31, 2015	1,527	$ 2	1,563	$ 1	1	$ (358)	$ 363,782	$ 36,569	$ 536,856	$ 936
pensation	—	—	—	—	—	—	7,425	—	—	7,4
tricted shares	19	—	—	—	—	—	—	—	—	—
ns paid to olders	—	—	—	—	—	—	—	—	(17,319)	(17
nmon stock	1,232	1	—	—	—	—	65,445	—	—	65,
of Class B Class A	72	—	(72)	—	—	—	10,568	—	(24,047)	(13
and accretion d stock	—	—	—	—	—	—	—	(2,669)	—	(2,6
e (loss)	—	—	—	—	—	—	—	(42,552)	(42,253)	(84
31, 2016	2,850	$ 3	1,491	$ 1	1	$ (358)	$ 447,220	$ (8,652)	$ 453,237	$ 891
e effect of f ASU	—	—	—	—	—	—	706	(706)	—	—
pensation	40	—	—	—	—	—	5,798	—	—	5,7
ns paid to olders	—	—	—	—	—	—	—	—	(562)	(56
nmon stock	185	—	—	—	—	—	8,334	—	—	8,3
lends on ock	250	1	—	—	—	—	17,499	(17,500)	—	—
of Class B Class A	1,010	1	(1,010)	(1)	—	—	122,864	—	(258,995)	(13
and accretion d stock	170	—	—	—	—	—	3,993	(7,924)	—	(3,9
e (loss)	—	—	—	—	—	—	—	(101,492)	(77,331)	(17
31, 2017	4,505	$ 5	481	$ —	1	$ (358)	$ 606,414	$ (136,274)	$ 116,349	$ 586
pensation	69	—	—	—	—	—	914	—	—	914

of Class B Class A	309	—	(309)	—	—	—	27,225	—	(68,382)	(41
n of preferred Class A	51	—	—	—	—	—	1,717	—	—	1,7
and accretion d stock	89	—	—	—	—	—	1,838	(7,737)	—	(5,8
e (loss)	—	—	—	—	—	—	—	(1,291,039)	(55,655)	(1,3
31, 2018	5,023	$ 5	172	$ —	1	$ (358)	$ 638,108	$ (1,435,050)	$ (7,688)	$ (80

(1) All share information presented has been recast to retrospectively adjust for the effects of the Reverse Stock Split, as defined in Note 14, “Stockholders’ and Mezzanine Equity”, effective on September 7, 2018.

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

Table of Contents

Jones Energy, Inc.

Consolidated Statements of Cash Flows

Years Ended December 31, 2018, 2017 and 2016

	Year ended December 31,		
(in thousands of dollars)	2018	2017	2016
Cash flows from operating activities			
Net income (loss)	$ (1,346,694)	$ (178,823)	$ (84,805)
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depletion, depreciation, and amortization	173,904	167,224	153,930
Exploration (dry hole and lease abandonment)	4,191	11,017	6,261
Impairment of oil and gas properties	1,331,785	149,648	—
Accretion of ARO liability	1,066	960	1,263
Amortization of debt issuance costs	10,649	3,955	4,060
Stock compensation expense	1,381	6,260	7,425
Deferred and other non-cash compensation expense	56	208	804
Amortization of deferred revenue	(1,555)	(1,854)	(2,384)
Loss on commodity derivatives	2,757	17,985	51,264
(Gain) loss on sales of assets	748	127	(14)
Gain on debt extinguishment	—	—	(99,530)
Deferred income tax provision	(61,835)	(47,082)	(27,767)
Change in liability under tax receivable agreement	(54,936)	(59,492)	—
Other - net	400	2,044	418
Changes in operating assets and liabilities			
Accounts receivable	8,897	(34,615)	2,276
Other assets	7,150	(12,330)	(675)
Accrued interest expense	11,841	(1,422)	(4,727)
Accounts payable and accrued liabilities	(25,697)	35,198	17,901
Net cash provided by operations	64,108	59,008	25,700
Cash flows from investing activities			
Additions to oil and gas properties	(198,468)	(245,364)	(264,462)
Net adjustments to purchase price of properties acquired	—	2,391	—
Proceeds from sales of assets	11,082	61,290	1,645
Acquisition of other property, plant and equipment	(360)	(586)	(310)
Current period settlements of matured derivative contracts	(53,147)	72,265	132,265
Net cash used in investing	(240,893)	(110,004)	(130,862)
Cash flows from financing activities			
Proceeds from issuance of long-term debt	20,000	162,000	130,000
Repayment of long-term debt	(231,000)	(129,000)	(62,000)
Proceeds from senior notes	438,867	—	—
Purchase of senior notes	—	—	(84,589)
Payment of debt issuance costs	(11,624)	(1,115)	—
Payment of cash dividends on preferred stock	—	(3,368)	(1,615)

Net distributions paid to JEH unitholders	—	(562)	(17,319)
Net payments for share based compensation	(466)	(462)	—
Proceeds from sale of common stock	—	8,333	65,446
Proceeds from sale of preferred stock	—	—	87,988
Net cash provided by financing	215,777	35,826	117,911
Net increase (decrease) in cash and cash equivalents	38,992	(15,170)	12,749
Cash and cash equivalents			
Beginning of period	19,472	34,642	21,893
End of period	$ 58,464	$ 19,472	$ 34,642
Supplemental disclosure of cash flow information			
Cash paid for interest, net of capitalized interest	$ 68,561	$ 49,101	$ 53,816
Cash paid for income taxes	—	2,318	—
Change in accrued additions to oil and gas properties	(3,377)	3,921	9,325
Asset retirement obligations incurred, including changes in estimate	695	924	(1,276)

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

Table of Contents

Jones Energy, Inc.

Notes to the Consolidated Financial Statements

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, certain members of management and through private equity funds managed by Metalmark Capital, among others. 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 remaining owners of JEH prior to the initial public offering ("IPO") of the Company (collectively, the "Class B shareholders") and can be exchanged (together with a corresponding number of common 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 of December 31, 2018, the Company held 5,024,491 JEH Units and all of the preferred units representing membership interests in JEH, and the remaining 172,193 JEH Units are held by the Class B shareholders. The Class B shareholders have no voting rights with respect to their economic interest in JEH, resulting in the Company reporting this ownership interest as a non-controlling interest.

The Company's certificate of incorporation also authorizes the Board of Directors of the Company (the "Board") to establish one or more series of preferred stock. Unless required by law or by any stock exchange on which our common stock is listed, the authorized shares of preferred stock will be available for issuance without further action. Rights and privileges associated with shares of preferred stock are subject to authorization by the Board and may differ from those of any and all other series at any time outstanding.

On August 25, 2016, the Company issued 1,840,000 shares of its 8.0% Series A Perpetual Convertible Preferred Stock, par value $0.001 per share (the "Series A preferred stock"), pursuant to a registered public offering at $50 per share, of which 1,804,478 remained issued and outstanding as of December 31, 2018. See Note 14, "Stockholders' and Mezzanine Equity".

On September 7, 2018, the Company effected a 1-for-20 reverse stock split of its Class A common stock and its Class B common stock. See Note 14, "Stockholders' and Mezzanine Equity".

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, spanning areas of Oklahoma and Texas. The Company's assets are located within the Eastern Anadarko Basin, targeting the liquids rich Woodford shale and Meramec formations in the Merge area of the STACK/SCOOP plays, and the Western Anadarko Basin, targeting the liquids rich Cleveland, Granite Wash, Tonkawa and Marmaton formations, 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") and in accordance with the rules and regulations of the

Securities and Exchange Commission. All significant intercompany transactions and balances have been eliminated in consolidation. The Company's financial position as of December 31, 2018 and 2017 and the financial statements reported for each of the three years in the period ended December 31, 2018 include the Company and all of its subsidiaries

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

Segment Information

The Company operates in one industry segment, which is the exploration, development and production of oil and natural gas, and all of its operations are conducted in one geographic area of the United States.

Use of Estimates

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

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

Cash

Cash and cash equivalents include highly liquid investments with a maturity of three months or less. At times, the amount of cash on deposit in financial institutions exceeds federally insured limits. Management monitors the soundness of the financial institutions it does business with, and believes the Company's risk is not significant.

Accounts Receivable

Accounts receivable—Oil and gas sales consist of uncollateralized accrued revenues due under normal trade terms, generally requiring payment within 30 to 60 days of production. Accounts receivable—Joint interest owners consist of uncollateralized joint interest owner obligations due within 30 days of the invoice date. Accounts receivable—Other consists at December 31, 2018 and at December 31, 2017 of derivative positions not settled as of the balance sheet date. No interest is charged on past due balances. The Company routinely assesses the recoverability of all material trade, joint interest and other receivables to determine their collectability, and reduces the carrying amounts by a valuation allowance that reflects management's best estimate of the amounts that may not be collected. As of December 31, 2018 and 2017, the Company did not have significant allowances for doubtful accounts.

Concentration of Risk

Substantially all of the Company's accounts receivable are related to the oil and gas industry. This concentration of entities may affect the Company's overall credit risk in that these entities may be affected similarly by changes in economic and other conditions, including declines in commodity prices. As of December 31, 2018, 73% of Accounts receivable—Oil and gas sales were due from four purchasers and 35% of Accounts receivable Joint interest owners were due from six working interest owner. As of December 31, 2017, 71% of Accounts receivable—Oil and gas sales were due from three purchasers and 59% of Accounts receivable Joint interest owners were due from five working interest owners. As of December 31, 2016, 77% of Accounts receivable—Oil and gas sales are due from four purchasers and 48% of Accounts receivable—Joint interest owners are due from five working interest owners. If any or all of these significant counterparties were to fail to pay amounts due to the Company, the Company's financial position and results of operations could be materially and adversely affected.

Financial instruments that potentially subject the Company to concentration of credit risk consist principally of cash deposits. Accounts at each institution are insured by the Federal Deposit Insurance Corporation ("FDIC") up to $250,000. As of December 31, 2018 and 2017, the Company had $62.9 million and $24.2 million in excess of the FDIC insured limit, respectively.

Dependence on Major Customers

The Company maintains a portfolio of crude oil and natural gas marketing contracts with large, established refiners and oil and gas purchasers. During the year ended December 31, 2018, the largest purchasers of our production were Plains Marketing LP (“Plains Marketing”), ETC Field Services LLC and CVR Energy, Inc., which accounted for approximately 26%, 20% and 19% of consolidated oil and gas sales, respectively. During the year ended December 31, 2017, the largest purchasers of our production were Plains Marketing LP (“Plains Marketing”) and ETC Field Services LLC, which accounted for approximately 40% and 22% of consolidated oil and gas sales, respectively. During the year ended December 31, 2016, the largest purchasers of our production were Plains Marketing LP (“Plains Marketing”) and ETC Field Services LLC, which accounted for approximately 37% and 24% of consolidated oil and gas sales, respectively.

Management believes that there are alternative purchasers and that it may be necessary to establish relationships with such new purchasers. However, there can be no assurance that the Company can establish such relationships and that those relationships will result in an increased number of purchasers. Although the Company is exposed to a concentration of credit risk, management believes that all of the Company’s purchasers are credit worthy.

Dependence on Suppliers

The Company’s industry is cyclical, and from time to time, there can be an imbalance between the supply of and demand for drilling rigs, equipment, services, supplies and qualified personnel. During periods of oversupply, there can be financial pressure on suppliers. If the financial pressure leads to work interruptions or stoppages, the Company could be materially and adversely affected. Management believes that there are adequate alternative providers of drilling and completion services although it may become necessary to establish relationships with new contractors. However, there can be no assurance that the Company can establish such relationships and that those relationships will result in increased availability of drilling rigs or other services, or that they could be obtained on the same terms.

Oil and Gas Properties

The Company accounts for its oil and natural gas exploration and production activities under the successful efforts method of accounting.

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

The Company capitalizes interest on expenditures for significant exploration and development projects that last more than six months while activities are in progress to bring the assets to their intended use.

On the sale or retirement of a proved field, the cost and related accumulated depletion, depreciation and amortization are eliminated from the field accounts, and the resultant gain or loss is recognized.

Capitalized amounts attributable to proved oil and gas properties are depleted by the unit of production method over the life of proved reserves, using the unit conversion ratio of six thousand cubic feet of gas to one barrel of oil equivalent.

Depletion of the costs of wells and related equipment and facilities, including capitalized asset retirement costs, net of salvage values, is computed using proved developed reserves. The reserve base used to calculate depreciation, depletion, and amortization for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves.

The Company reviews its proved oil and natural gas properties, including related wells and equipment, for impairment by comparing expected undiscounted future cash flows at a producing field level to the net capitalized cost of the asset. If the future undiscounted cash flows, based on the Company’s estimate of future commodity prices, operating costs, and production, are lower than the net capitalized cost, the capitalized cost is reduced to fair value. See Note 9, “Fair Value Measurement,” for further information regarding the method used to determine the fair value of oil and gas properties.

Table of Contents

The Company evaluates its unproved properties for impairment on a property by property basis. The Company's unproved property consists of acquisition costs related to its undeveloped acreage. The Company reviews the unproved property for indicators of impairment based on the Company's current exploration plans with consideration given to commodity prices, lease expiration dates, results of any drilling and geo science activity during the period, and known information regarding exploration and development activity by other companies on adjacent blocks. See Note 9, "Fair Value Measurement," for further information regarding impairment of unproved properties.

On the sale of an entire interest in an unproved property, gain or loss on the sale is recognized, taking into consideration the amount of any recorded impairment if the property had been assessed individually. If a partial interest in an unproved property is sold, the amount received is treated as a reduction of the cost of the interest retained.

Other Property, Plant and Equipment

Other property, plant and equipment is depreciated on a straight line basis over the estimated useful lives of the property, plant and equipment, which range from three years to ten years.

Oil and Gas Sales Payable

Oil and gas sales payable represents amounts collected from purchasers for oil and gas sales, which are due to other revenue interest owners. Generally, the Company is required to remit amounts due under these liabilities within 60 days of receipt.

Accrued Liabilities

Accrued liabilities consisted of the following at December 31, 2018 and 2017:

(in thousands of dollars)	December 31, 2018	December 31, 2017
Accrued interest expense	$ 23,949	$ 12,109
Joint interest owners prepayments	8,000	4,061
Commodity derivative liabilities	2,475	14
Other accrued liabilities	3,375	5,420
Total accrued liabilities	$ 37,799	$ 21,604

Commodity Derivatives

The Company records its commodity derivative instruments on the Consolidated Balance Sheet as either an asset or liability measured at its fair value. Changes in the derivative's fair value are recognized currently in earnings, unless specific hedge accounting criteria are met. During the years ended December 31, 2018, 2017 and 2016, the Company elected not to designate any of its commodity price risk management activities as cash flow or fair value hedges. The changes in the fair values of outstanding financial instruments are recognized as gains or losses in the period of change.

Although the Company does not designate its commodity derivative instruments as cash flow hedges, management uses those instruments to reduce the Company's exposure to fluctuations in commodity prices related to its natural gas and oil production. Net gains and losses, at fair value, are included on the Consolidated Balance Sheet as current or noncurrent assets or liabilities based on the anticipated timing of cash settlements under the related contracts. Changes in the fair value of commodity derivative contracts are recorded in earnings as they occur and are included in other income (expense) on the Consolidated Statement of Operations. See Note 9, “Fair Value Measurement,” for disclosure about the fair values of commodity derivative instruments.

Asset Retirement Obligations

The Company's asset retirement obligations ("ARO") consist of future plugging and abandonment expenses on oil and natural gas properties. The Company estimates an ARO for each well in the period in which it is incurred based on estimated present value of plugging and abandonment costs, increased by an inflation factor to the estimated date that the well would be plugged. The resulting liability is recorded by increasing the carrying amount of the related long-lived asset. The liability is then accreted to its then-present value each period and the capitalized cost is depleted over the useful life of the related asset. If the liability is settled for an amount other than the recorded amount, a gain or loss is recognized. The ARO is classified as current or noncurrent based on the expect timing of payments.

Table of Contents

Revenue Recognition

Revenue is measured based on a consideration specified in a contract with a customer, and excludes any amounts collected on behalf of third parties. The Company recognizes revenue when it satisfies a performance obligation by transferring control over a product or service to a customer. We generally consider the delivery of each unit (Bbl or MMBtu) to be separately identifiable and represents a distinct performance obligation that is satisfied at a point-in-time once control of the product has been transferred to the customer upon delivery to an agreed upon delivery point. Transfer of control typically occurs when the products are delivered to the purchaser, and title has transferred.

Revenue is recognized at a point in time as a result of not meeting any of the three criteria required for recognition over time.

Certain transportation and processing costs associated with fixed fee contracts where title transfers to the customer at the tailgate of the processing plant and we pay a gathering and processing fee are recognized at the time of title transfer. These costs are presented as Transportation and processing costs on the Consolidated Statement of Operations.

The Company enters into marketing agreements with our non-operating partners to market and sell their share of production to third parties. Under these arrangements, we record revenue for our share of the production (i.e. we, as the operator, record revenue on a net basis). Distributions are made to our non-operating partners for their share of the revenue.

As part of our adoption of ASC 606, we used practical expedients permitted by the standard when applicable. These practical expedients included:

- Applying the new guidance only to contracts that are not completed as of January 1, 2018;
- Taxes assessed by a governmental authority that are both imposed on and concurrent with a specific revenue-producing transaction, that are collected by the Company from a customer, are excluded from revenue;
- The Company recognizes the incremental cost of obtaining contracts as an expense when incurred if the amortization period of the assets that the Company otherwise would have recognized is one year or less. These costs are included in General and administrative expenses;
- For our product sales that have a contact term greater than one year, we have utilized the practical expedient in ASC 606, which states that a company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under our product sales contracts, each unit of product delivered to the customer represents a separate performance obligation; therefore, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required; and
- For our product sales that have a contract term of one year or less, we have utilized the practical expedient in ASC 606, which states that a company is not required to disclose the transaction price allocated to remaining performance obligations if the performance obligation is part of the contract that has an original expected duration of one year or less.

Income Taxes

The Company records a federal and state income tax liability 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.

Income taxes are accounted for under the asset and liability method, which requires recognition of deferred tax assets and liabilities for the expected future tax consequences of events that have been included in the financial statements.

Under this method, deferred tax assets and liabilities are determined based on the differences between the financial statements and tax basis of assets and liabilities using enacted tax rates in effect for the year in which differences are expected to be recovered or settled pursuant to the provisions of ASC 740—Income Taxes. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in income in the period that includes the enactment date.

On December 22, 2017, the US Congress enacted the Tax Cuts and Jobs Act (Tax Reform Legislation), which made significant changes to US federal income tax law affecting us. See Note 13, “Income Taxes.”

Table of Contents

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

Comprehensive Income

The Company has no elements of comprehensive income other than net income.

Recent Accounting Pronouncements

Adopted in the current year:

In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers," which creates a new topic in the Accounting Standards Codification ("ASC"), topic 606, "Revenue from Contracts with Customers." This standard 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 may be applied on either a full or modified retrospective basis and are now effective for interim and annual reporting periods beginning after December 15, 2017. Therefore, the Company has adopted Update 2014-09 and Update 2015-14 effective as of January 1, 2018. The change was applied on a modified retrospective basis, which did not result in a cumulative effect adjustment to retained earnings. However, adoption did result in certain changes in presentation of gross revenues and expenses on the Company's Consolidated Statement of Operations; such costs were historically offset against revenues. Upon adoption, we have also expanded disclosures related to revenue recognition. See Note 5, "Revenue Recognition."

In January 2017, the FASB issued ASU 2017-01, "Business Combinations" (Topic 805). The amendments under this ASU provide guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions/disposals or business combinations by providing a screen to determine when an integrated set of assets and activities is not a business. The screen requires that when substantially all of the fair value of the gross assets acquired, or disposed of, is concentrated in a single identifiable asset or a group of similar identifiable assets, the set is not a business, therefore reducing the number of transactions that need to be further evaluated for treatment as a business combination. This new guidance is effective for annual periods beginning after December 15, 2017. Therefore, the Company adopted ASU 2017-01 effective as of January 1, 2018 applied prospectively, which did not have a material impact on our financial statements; however these amendments could result in the recording of fewer business combinations in future periods.

To be adopted in a future period:

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 and mineral 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. In July 2018, the FASB issued ASU 2018-11, “Leases” (Topic 842) Targeted Improvements, which allows issuers an additional (and optional) transition method of adoption. Under the original standard issued in 2016, lessees and lessors were required to 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. However, under the new transition method allowed for in the standard released in 2018, an entity may elect to initially apply the new leases standard at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption with no adjustment to previously reported results. The amendments are effective for interim and annual reporting periods beginning after December 15, 2018.

We adopted ASU 2016-02 effective as of January 1, 2019 using a modified retrospective transition method applied at the adoption date. No cumulative-effect adjustment to the opening balance of retained earnings was required as a result of adoption. Upon adoption, we recognized a right of use asset and lease liability of approximately $1.6 million associated with two real estate leases. We elected to apply the package of practical expedients provided in the standards update that allow, among other things, the carry forward of historical lease classification, as well as additional practical expedients related to land easements, short-term leases, and non-lease components. The Company did not elect the practical expedient related to hindsight.

In June 2018, the FASB issued ASU 2018-07 "Compensation-Stock Compensation" (Topic 718). The amendments under this ASU provide an expanded scope of Topic 718, to include share-based payment transactions for acquiring goods and services from non-employees. The new standards update is effective for interim and annual periods beginning after December 15, 2018. We adopted ASU 2018-07 effective as of January 1, 2019. No cumulative-effect adjustment to the opening balance of retained earnings was required as a result of adoption.

In August 2018, the FASB issued ASU 2018-13, “Fair Value Measurement” (Topic 820). The amendments under this ASU provide additional disclosure requirements that eliminates the requirement to disclose transfers between Level 1 and Level 2 of the fair value hierarchy and provides for additional disclosures for Level 3 fair value measurements. This new standards update is effective for interim and annual periods beginning after December 15, 2019. Early adoption is permitted. The Company is currently evaluating the impacts of the amendments to our financial statements and accounting practices for fair value measurement, as well as the method of adoption. We anticipate adoption of ASU 2018-13 effective as of January 1, 2020.

3. Liquidity and Going Concern

The Company has incurred losses from operations in each of the years ended December 31, 2018, 2017 and 2016. As a result of the current low commodity prices and the Company’s significant indebtedness , the Company may not be able to generate sufficient cash from operations to satisfy the interest obligations on its Secured and Unsecured notes as they become due. Pursuant to the Company's indebtedness under the Secured and Unsecured Notes, it will owe a total of approximately $84 million for the year ending December 31, 2019. See Note 7 “Long Term Debt” for further information.

The Company’s ability to continue as a going concern is subject to, among other factors, its ability to monetize assets, its ability to obtain financing or refinance existing indebtedness, its ability to continue its cost cutting efforts for long–term rig and support services, the production rates achieved from current projects, oil and natural gas prices, the number of commercially viable hydrocarbon discoveries made and the quantities of hydrocarbons discovered, the speed and cost with which the Company can bring such discoveries to production and the actual cost of exploration, appraisal and development of its prospects.

The Company has substantial debt obligations requiring significant interest payments semi-annually. The ongoing capital and operating expenditures, including the debt interest payments, will vastly exceed the revenue expected to be generated from operations in the near term. There can be no assurance that the Company will be able to obtain additional funding on satisfactory terms or at all. In addition, no assurance can be given that any such financing, if obtained, will

Table of Contents

be adequate to meet the Company's capital needs and support its growth. If additional funding cannot be obtained on a timely basis and on satisfactory terms, then the Company's operations would be materially negatively impacted.

If the Company becomes unable to continue as a going concern, the Company may find it necessary to file a voluntary petition for reorganization under the United States Bankruptcy Code in order to provide it additional time to identify an appropriate solution to its financial situation and implement a plan of reorganization aimed at improving our capital structure.

The accompanying consolidated financial statements have been prepared under the assumption that the Company will continue as a going concern, which contemplates the continuity of operations and the realization of assets and the satisfaction of liabilities as they come due in the normal course of business. The Company's current circumstances raise substantial doubt about its ability to continue to operate as a going concern. The accompanying consolidated financial statements do not include any adjustments that might be necessary should the Company be unable to continue as a going concern.

4. Acquisitions and Divestitures

During the three year period ended December 31, 2018, the Company entered into several purchase and sale agreements (as described below). One business combination occurred during the twelve months ended December 31, 2016. However, no business combinations occurred during the twelve months ended December 31, 2018 and 2017.

Western Anadarko Acquisition

On August 25, 2016, JEH acquired producing and undeveloped oil and gas assets in the Western Anadarko Basin (the "Anadarko Acquisition") for final consideration of $25.9 million. This transaction was accounted for as a business combination. The Company allocated $32.3 million to "Oil and gas properties," with $3.0 million allocated to "Unproved" properties, $17.0 million allocated to "Proved" properties, and $12.3 million allocated to "Wells and equipment and related facilities", based on the respective fair values of the assets acquired. Additionally, the Company allocated $6.4 million to our ARO liability associated with those proved properties. The Anadarko Acquisition did not result in a significant impact to revenues or net income and as such, pro forma financial information is not included. The Company funded the Anadarko Acquisition with cash on hand.

The assets acquired in the Anadarko Acquisition included interests in 174 wells, 59% of which were operated by the company, and approximately 25,000 net acres in Lipscomb and Ochiltree Counties in the Texas Panhandle. As of the closing date, the acquired acreage was producing approximately 900 barrels of oil equivalent per day.

Merge Acquisition

On September 22, 2016, JEH acquired oil and gas properties located in the Merge area of the STACK/SCOOP plays (the "Merge") in Central Oklahoma (the "Merge Acquisition") from SCOOP Energy Company, LLC for cash consideration of $134.4 million, net of the final working capital settlement of $2.4 million received in the first quarter of 2017. The oil and gas properties acquired in the Merge Acquisition, on a closed and funded basis, principally consist of 16,975 undeveloped net acres in Canadian, Grady and McClain Counties, Oklahoma. This transaction has been accounted for as an asset acquisition. The Company used proceeds from our equity offerings to fund the purchase. See Note 14 "Stockholders' and Mezzanine Equity".

Arkoma Divestiture

As of June 30, 2017, the Arkoma Assets and related liabilities (the "Held for sale assets") were classified as held for sale due to the pending Arkoma Divestiture. Upon the classification change occurring on June 30, 2017, the Company ceased recording depletion on the Held for sale assets. Based on the Company's sales price, the Company recognized an estimated impairment charge of $148.0 million at June 30, 2017 which has been included in Impairment of oil and gas properties on the Company's Consolidated Statement of Operations.

On August 1, 2017, JEH closed its previously announced agreement to sell its Arkoma Basin properties (the "Arkoma Assets") for a sale price of $65.0 million, prior to customary effective date adjustments of $7.3 million, and subject to customary post-close adjustments (the “Arkoma Divestiture”). JEH may also receive up to $2.5 million in contingent payments based on natural gas prices through the period ending October 1, 2019. As of December 31, 2018, $0.3 million has been recorded related to this contingent payment. The contingent payment was recorded as a gain in Other income (expense) on the Company’s Consolidated Statement of Operations of $0.3 million during the year ended December 31, 2018. No contingent payment gains were recorded during the year ended December 31, 2017.

Year Ended December 31, 2018

Sales of non-core assets resulted in net gains of $0.8 million during the year ended December 31, 2018 which have been included in Other income (expense) on the Company’s Consolidated Statement of Operations.

5. Revenue Recognition

Adoption of ASC Topic 606, Revenue from Contracts with Customers

On January 1, 2018, the Company adopted ASC Topic 606 (“ASC 606”), Revenue from Contracts with Customers, using the modified retrospective approach, which was applied to those contracts which were not completed as of January 1, 2018. Results for reporting periods beginning January 1, 2018, are presented in accordance with ASC 606, while prior period amounts are reported in accordance with ASC Topic 605, Revenue Recognition.

In accordance with ASC 606, the Company now records transportation and processing costs that are incurred before control of its product has transferred to the customer (i.e. fixed fee contracts) as a separate expense line item on the Consolidated Statement of Operations. Prior to the adoption of ASC 606, these transportation and processing costs were recorded as a reduction of Oil and gas sales on the Consolidated Statement of Operations. See further discussion below in “Nature of revenue” related to transportation and processing costs associated with fixed fee contracts. Revenue under

Table of Contents

ASC 606 is recognized at the same point in time at which revenue was recognized under ASC Topic 605, thus there was no impact to net income (loss) or opening retained earnings as a result of adopting ASC 606.

The following table presents the impact to the Consolidated Statement of Operations as a result of adopting ASC 606.

	Year Ended December 31, 2018		
(in thousands of dollars except per share data)	Amounts under ASC 606	Adoption impact	Amounts under ASC 605 (1)
Operating revenues			
Oil and gas sales	$ 236,873	$ (3,368)	$ 233,505
Other revenues, net	(516)	—	(516)
Total operating revenues	236,357	(3,368)	232,989
Operating costs and expenses			
Lease operating	44,921	—	44,921
Production and ad valorem taxes	12,087	—	12,087
Transportation and processing costs	3,368	(3,368)	—
Exploration	8,157	—	8,157
Depletion, depreciation and amortization	173,904	—	173,904
Impairment of oil and gas properties	1,331,785	—	1,331,785
Accretion of ARO liability	1,066	—	1,066
General and administrative	31,204	—	31,204
Other operating	250	—	199
Total operating expenses	1,606,742	(3,368)	1,603,323
Operating income (loss)	(1,370,385)	—	(1,370,334)
Other income (expense)			
Interest expense	(89,328)	—	(89,328)
Net gain (loss) on commodity derivatives	(2,757)	—	(2,757)
Other income (expense)	53,935	—	53,935
Other income (expense), net	(38,150)	—	(38,150)
Income (loss) before income tax	(1,408,535)	—	(1,408,484)
Income tax provision (benefit)	(61,841)	—	(61,841)
Net income (loss)	(1,346,694)	—	(1,346,643)
Net income (loss) attributable to non-controlling interests	(55,655)	—	(55,604)
Net income (loss) attributable to controlling interests	$ (1,291,039)	$ —	$ (1,291,039)
Dividends and accretion on preferred stock	(7,737)	—	(7,737)
Net income (loss) attributable to common shareholders	$ (1,298,776)	$ —	$ (1,298,776)
Earnings (loss) per share (2) :			
Basic - Net income (loss) attributable to common shareholders	$ (271.94)	$ —	$ (271.94)
Diluted - Net income (loss) attributable to common shareholders	$ (271.94)	$ —	$ (271.94)
Weighted average Class A shares outstanding (2) :			

Basic	4,776	—	4,776
Diluted	4,776	—	4,776

(1) This column excludes the impact of adopting ASC 606 and is consistent with the presentation prior to January 1, 2018.
(2) All share and earnings per share information presented has been recast to retrospectively adjust for the effects of the Reverse Stock Split, as defined in Note 14, "Stockholders' and Mezzanine Equity", effective on September 7, 2018.

Nature of revenue

Our revenues are primarily derived from the sale of oil and natural gas production, and from the sale of NGLs that are extracted from our natural gas. Sales of oil, natural gas, and NGLs from our interests in producing wells are recognized when we satisfy a performance obligation by transferring control of a product to a customer. Our oil and gas production is sold to purchasers under either short-term or long-term contracts at market-based prices. The sales prices for oil, natural gas, and NGLs are adjusted for transportation and other related deductions. These deductions are based on contractual data and do not require significant judgment. The revenue deductions reflect actual charges based on purchaser statements. Since there is a ready market for oil and natural gas, we sell the majority of production soon after it is produced at various locations. Payment is generally received one month after the sale has occurred.

Under our oil sales contracts, we generally sell oil to the purchaser from storage tanks near the wellhead and collect a contractually agreed upon index price, net of pricing differentials. We transfer control of the product from the storage

Table of Contents

tanks to the purchaser and recognize revenue based on the contract price. For pipeline sales, title transfers upon oil passing the inlet or delivery point.

Under our natural gas sales contracts, we deliver natural gas to the purchaser at an agreed upon delivery point. Natural gas is transported from our wellheads to delivery points specified under sales contracts. To deliver natural gas to these points, the Company or third parties gather, compress, process and transport our natural gas. We maintain ownership and control of the natural gas during gathering, compression, processing, and transportation. Our sales contracts provide that we receive a specific index price adjusted for pricing differentials. We transfer ownership and control of the product at the delivery point and recognize revenue based on the contract price. The sales prices for natural gas is adjusted for transportation and other related deductions. The revenue deductions reflect actual charges based on purchaser statements. The costs to gather, compress, process, and transport the natural gas are separately presented as Transportation and processing costs on the Consolidated Statement of Operations.

NGLs, which are extracted from natural gas through processing, are either sold by us directly or by the processor under processing contracts. For NGLs sold by us directly, our sales contracts provide that we deliver the product to the purchaser at an agreed upon delivery point and that we receive a specific index price adjusted for pricing differentials. We transfer control of the product to the purchaser at the delivery point and recognize revenue based on the contract price. Several of our revenue contracts are fixed fee where title transfers to the customer at the tailgate of the processing plant and we pay a gathering and processing fee. Gathering and processing costs associated with fixed fee contracts have a distinct service payable and, as a result of the adoption of ASC 606, these costs are reported as a separate expense line item titled Transportation and processing costs on the Consolidated Statement of Operations. Prior to the adoption of ASC 606, these transportation and processing costs were recorded as a reduction of Oil and gas sales on the Consolidated Statement of Operations. There is no impact to the current method of recognizing revenue for percentage of recovery contracts for gathering and processing costs which, in accordance with ASC 606, remain deducted from sales proceeds and are recorded as a reduction of Oil and gas sales on the Consolidated Statement of Operations.

Significant accounting policy

Revenue is measured based on a consideration specified in a contract with a customer, and excludes any amounts collected on behalf of third parties. The Company recognizes revenue when it satisfies a performance obligation by transferring control over a product or service to a customer. We generally consider the delivery of each unit (Bbl or MMBtu) to be separately identifiable and represents a distinct performance obligation that is satisfied at a point-in-time once control of the product has been transferred to the customer upon delivery to an agreed upon delivery point. Transfer of control typically occurs when the products are delivered to the purchaser, and title has transferred.

Revenue is recognized at a point in time as a result of not meeting any of the three criteria required for recognition over time.

Certain transportation and processing costs associated with fixed fee contracts where title transfers to the customer at the tailgate of the processing plant and we pay a gathering and processing fee are recognized at the time of title transfer. These costs are presented as Transportation and processing costs on the Consolidated Statement of Operations.

The Company enters into marketing agreements with our non-operating partners to market and sell their share of production to third parties. Under these arrangements, we record revenue for our share of the production (i.e. we, as the operator, record revenue on a net basis). Distributions are made to our non-operating partners for their share of the revenue, in accordance with the governing states' remittance policy.

As part of our adoption of ASC 606, we used practical expedients permitted by the standard when applicable. These practical expedients included:

· Applying the new guidance only to contracts that are not completed as of January 1, 2018;

· Taxes assessed by a governmental authority that are both imposed on and concurrent with a specific revenue-producing transaction, that are collected by the Company from a customer, are excluded from revenue;

· The Company recognizes the incremental cost of obtaining contracts as an expense when incurred if the amortization period of the assets that the Company otherwise would have recognized is one year or less. These

Table of Contents

costs are included in General and administrative expenses;

· For our product sales that have a contact term greater than one year, we have utilized the practical expedient in ASC 606, which states that a company is not required to disclose the transaction price allocated to remaining performance obligations if the variable consideration is allocated entirely to a wholly unsatisfied performance obligation. Under our product sales contracts, each unit of product delivered to the customer represents a separate performance obligation; therefore, future volumes are wholly unsatisfied, and disclosure of the transaction price allocated to remaining performance obligations is not required; and

· For our product sales that have a contract term of one year or less, we have utilized the practical expedient in ASC 606, which states that a company is not required to disclose the transaction price allocated to remaining performance obligations if the performance obligation is part of the contract that has an original expected duration of one year or less.

Disaggregation of revenue

The following tables present quantitative information about disaggregated revenues from contracts with customers by commodity and region of production for the year ended December 31, 2018 as presented under ASC 606.

	Year Ended December 31, 2018			
(in thousands of dollars)	Oil	Natural gas	NGLs	Total
Eastern Anadarko	$ 57,171	$ 8,661	$ 23,840	$ 89,672
Western Anadarko	84,048	26,033	37,120	147,201
Total	$ 141,219	$ 34,694	$ 60,960	$ 236,873

The following tables present quantitative information about disaggregated revenues from contracts with customers by commodity and region of production for the years ended December 31, 2017 and 2016 as presented under ASC 605 since the Company adopted ASC 606 under the modified retrospective method which does not require adjustment of prior period amounts.

	Year Ended December 31, 2017 (1)			
(in thousands of dollars)	Oil	Natural gas	NGLs	Total
Eastern Anadarko	$ 16,339	$ 3,265	$ 7,173	$ 26,777
Western Anadarko	76,868	38,926	43,822	159,616
Total	$ 93,207	$ 42,191	$ 50,995	$ 186,393

(1) Prior period amounts have not been adjusted under the modified retrospective method.

	Year Ended December 31, 2016 (1)			
(in thousands of dollars)	Oil	Natural gas	NGLs	Total
Eastern Anadarko	$ 12	$ 2	$ 2	$ 16
Western Anadarko	63,724	31,432	29,705	124,861
Total	$ 63,736	$ 31,434	$ 29,707	$ 124,877

(1) Prior period amounts have not been adjusted under the modified retrospective method.

During the three years ended December 31, 2018, the timing of revenue recognition for all products was transferred at a point in time. No products and/or services were transferred over time.

Table of Contents

Contract balances

The following table provides information about receivables, contract assets, and contract liabilities from contracts with customers at December 31, 2018 and 2017.

(in thousands of dollars)	December 31, 2018	December 31, 2017
Accounts receivable, net		
Oil and gas sales	$ 33,954	$ 34,492
Other current liabilities		
Contract liabilities	$ 1,079	$ —

Accounts receivable – Oil and gas sales consist of uncollateralized accrued revenues due under normal trade terms, generally requiring payment within 30 to 60 days of production. Under our sales contracts, payment is unconditional after our performance obligations have been satisfied under ASC 606. Accordingly, unconditional rights to consideration are presented separately as a receivable. Since our sales contracts are not conditional on factors other than the passage of time, the contracts do not give rise to contract assets under ASC 606.

Other current liabilities – contract liabilities represent estimated fees for minimum volume and drilling commitments associated with certain revenue contracts with customers.

6. 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 December 31, 2018 and 2017:

(in thousands of dollars)	December 31, 2018	December 31, 2017
Mineral interests in properties		
Unproved	$ 96,770	$ 164,087
Proved	961,314	893,246
Wells and equipment and related facilities	1,617,330	1,434,383
	2,675,414	2,491,716
Less: Accumulated depletion and impairment	(2,403,568)	(894,676)
Net oil and gas properties	$ 271,846	$ 1,597,040

There were no exploratory wells drilled during the years ended December 31, 2018 and 2017 and, as such, no associated costs were capitalized. No exploratory wells resulted in exploration expense during the three years ended December 31, 2018.

The Company capitalizes interest on expenditures for significant exploration and development projects that last more than six months while activities are in progress to bring the assets to their intended use. During the years ended December 31, 2018 and 2017, the Company capitalized $0.2 million and $0.4 million, respectively, associated with such in progress projects. Costs incurred to maintain wells and related equipment are charged to expense as incurred.

Depletion of oil and gas properties amounted to $172.9 million, $166.2 million, and $152.7 million for the years ended December 31, 2018, 2017, and 2016, respectively.

The Company continues to monitor its proved and unproved properties for impairment. Impairment charges of $1,332.0 million were recognized during the year ended December 31, 2018. See Note 9, “Fair Value Measurement,” for further information. During the year ended December 31, 2017, as noted in Note 4, “Acquisitions and Divestitures - Arkoma Divestiture,” the Company recognized an impairment charge of $148.0 million during the second quarter of 2017 based on the Company’s negotiated selling price of the Arkoma Basin oil and gas property assets and related liabilities. Additionally, the Company recognized an impairment charge of $1.6 million during the fourth quarter of 2017 related to minor properties, which we are not currently developing. No impairments of proved or unproved properties were recorded during the year ended December 31, 2016.

Table of Contents

Other Property, Plant and Equipment

Other property, plant and equipment consisted of the following at December 31, 2018 and 2017:

(in thousands of dollars)	December 31, 2018	December 31, 2017
Leasehold improvements	$ 1,186	$ 1,186
Furniture, fixtures, computers and software	4,411	4,410
Vehicles	1,922	1,922
Aircraft	—	910
Land	261	—
Other	238	210
	8,018	8,638
Less: Accumulated depreciation and amortization	(6,379)	(5,919)
Net other property, plant and equipment	$ 1,639	$ 2,719

Depreciation and amortization of other property, plant and equipment amounted to $1.0 million, $1.0 million, and $1.2 million during the years ended December 31, 2018, 2017 and 2016, respectively.

7. Long Term Debt

Long-term debt consisted of the following at December 31, 2018 and 2017:

(in thousands of dollars)	December 31, 2018	December 31, 2017
Revolver	$ —	$ 211,000
2022 Notes	409,148	409,148
2023 Notes	150,000	150,000
2023 First Lien Notes	450,000	—
Total principal amount	1,009,148	770,148
Less: unamortized discount	(13,342)	(5,228)
Less: debt issuance costs, net	(13,649)	(5,604)
Total carrying amount	$ 982,157	$ 759,316

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 (collectively, 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 certain indebtedness and for working capital and general corporate purposes. 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. The 2022 Notes mature on April 1, 2022.

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 (as defined below) 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. The 2023 Notes mature on March 15, 2023.

During 2016, the Company purchased an aggregate principal amount of $190.9 million of its senior unsecured notes through several open-market and privately negotiated purchases. The Company 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 $99.5 million during the year ended December 31, 2016, on a pre-tax basis. This income was recorded in Gain on debt extinguishment on the Company’s Consolidated Statement of Operations. Of the

Table of Contents

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. No additional purchases were made during 2017 and 2018.

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 December 31, 2018, the Company was in compliance with the indentures governing the 2022 Notes and 2023 Notes.

Senior Secured First Lien Notes due 2023

On February 14, 2018, the Issuers sold $450.0 million of 9.25% senior secured first lien notes due 2023 (the "2023 First Lien Notes") at an offering price equal to 97.526% of par in an offering exempt from registration under the Securities Act. The 2023 First Lien Notes are senior secured first lien obligations of JEH and Jones Energy Finance Corp. and are guaranteed on a senior secured first lien basis by the Company and each of the existing and future restricted subsidiaries of JEH and Jones Energy Finance Corp. The Company used the net proceeds from the offering to repay all but $25.0 million of the outstanding borrowings under the Revolver, to fund drilling and completion activities, and for other general corporate purposes. The 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, 2018. During the year ended December 31, 2018, the Company capitalized $11.4 million of loan costs associated with the issuance of the 2023 First Lien Notes.

As of December 31, 2018, the Company was in compliance with the indenture governing the 2023 First Lien Notes.

Other Long-Term Debt

The Company has a Senior Secured Revolving Credit Facility (the "Revolver") with a syndicate of banks. At the beginning of 2018, the borrowing base under the Revolver was $350.0 million. In connection with the offering of the 2023 First Lien Notes, the borrowing base was reduced to $50.0 million effective February 14, 2018. On June 27, 2018, in connection with an amendment described below, the borrowing base was further reduced to $25.00. The

Company’s oil and gas properties are pledged as collateral to secure its obligations under the Revolver. The Revolver matures on November 6, 2019.

In connection with the offering of the 2023 First Lien Notes, on February 14, 2018, JEH amended the Revolver to, among other things, (a) permit the issuance of the 2023 First Lien Notes and additional senior secured notes in an aggregate principal amount, together with the notes issued pursuant to this offering, not to exceed $700.0 million, (b) permit the incurrence of liens securing the 2023 First Lien Notes pursuant to the terms of a collateral trust agreement, (c) reduce the borrowing base under the Revolver to $50.0 million and (d) suspend testing of our senior secured leverage ratio until March 31, 2019.

On June 27, 2018, the Company entered into an amendment to the Revolver to, among other things (a) remove the financial maintenance covenants contained therein, including the current ratio, total leverage ratio and senior secured leverage ratio, (b) align certain of the other covenants contained therein to be consistent with the terms of the indenture governing the 2023 First Lien Notes, (c) reduce lender commitments to $25.00, and (d) reduce the borrowing base to $25.00 for the remainder of the life of the facility. Additionally, outstanding borrowings of $25.0 million were repaid in connection with the closing of the amendment. The Company does not currently have any borrowings under the Revolver.

The Company recognized accelerated amortization of debt issuance costs of $3.8 million during the year ended December 31, 2018 associated with the modification of the Revolver, which was recorded as Interest expense on the Company's Consolidated Statement of Operations.

The terms of the Revolver require the Company to make periodic payments of interest on the loans outstanding thereunder, if any, 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.

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 2.75% to 3.75% 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 1.75% to 2.75% based on the level of borrowing base utilization at such time. The average interest rate under the Revolver was 4.46% on an average outstanding balance of $74.3 million through June 27, 2018.

Total interest and commitment fees under the Revolver were $1.8 million, $6.6 million, and $5.3 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Jones Energy, Inc. and its consolidated subsidiaries are subject to certain covenants under the Revolver, which are substantially similar to those set forth in the indenture governing the 2023 First Lien Notes or are otherwise customary for facilities of this type and which limit our ability to, among other things: borrow money or issue guarantees; pay dividends, redeem capital stock or make other restricted payments; incur liens to secure indebtedness; sell certain assets; enter into transactions with our affiliates; or merge with another person or sell substantially all of our assets.

As of December 31, 2018, the Company was in compliance with all terms of our Revolver.

8. 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 December 31, 2018:

Hedging Positions

	December 31, 2018				
		Low	High	Weighted Average	Final Expiration
Oil swaps	Exercise price	$ 49.85	$ 50.12	$ 49.98	December 2020
	Barrels per month	40,000	60,000	50,000	
Natural gas swaps	Exercise price	$ 2.76	$ 2.86	$ 2.81	December 2020
	MMbtu per month	700,000	1,100,000	865,833	
Oil collars	Puts (floors)	$ 45.00	$ 50.00	$ 48.52	December 2019
	Calls (ceilings)	$ 56.60	$ 61.00	$ 59.64	
	Net barrels per month	65,000	73,000	67,500	
Natural gas collars	Puts (floors)	$ 2.55	$ 2.55	$ 2.55	December 2019
	Calls (ceilings)	$ 3.08	$ 3.41	$ 3.19	
	Net MMbtu per month	950,000	1,050,000	990,833	

The Company recognized net losses on derivative instruments of $2.8 million, $18.0 million and $51.3 million for the years ended December 31, 2018, 2017 and 2016, respectively.

The Company routinely enters into oil and natural gas swap contracts as seller, thus resulting in a fixed price. During 2016 and 2017, the Company realized 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 realized by purchasing, as opposed to selling,

Table of Contents

oil and natural gas swap contracts for an 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 left the underlying production open to fluctuations in market prices prior to the point when the Company began to re-hedge the unhedged production. Based on the original contract terms of these purchased swaps, the gains would have been recognized as the hedge contracts mature in 2018 and 2019. However, during the year ended December 31, 2017, the Company unwound all of its realized 2018 and 2019 hedges resulting in approximately $42.8 million of recognized gains which have been included in Net gain (loss) on commodity derivatives on the Company's Consolidated Statement of Operations.

Offsetting Assets and Liabilities

As of December 31, 2018, 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.

The following table presents information about our commodity derivative contracts that are netted on our Consolidated Balance Sheet as of December 31, 2018 and 2017:

(in thousands of dollars)	Gross Amounts of Recognized Assets / Liabilities	Gross Amounts Offset in the Balance Sheet	Net Amounts of Assets / Liabilities Presented in the Balance Sheet	Gross Amounts Not Offset in the Balance Sheet	Net Amount
December 31, 2018					
Commodity derivative contracts					
Assets	$ 9,934	$ (3,516)	$ 6,418	$ —	$ 6,418
Liabilities	(3,886)	3,516	(370)	—	(370)
December 31, 2017					
Commodity derivative contracts					
Assets	$ 8,572	$ (4,926)	$ 3,646	$ —	$ 3,646
Liabilities	(50,423)	4,926	(45,497)	—	(45,497)

9. 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

Table of Contents

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 December 31, 2018 and 2017, by consolidated balance sheet caption and by valuation hierarchy, as described above are as follows:

(in thousands of dollars)	December 31, 2018			
	Fair Value Measurements Using			
Commodity Price Hedges	(Level 1)	(Level 2)	(Level 3)	Total
Current assets	$ —	$ 1,483	$ 3,520	$ 5,003
Long-term assets	—	1,415	—	1,415
Current liabilities	—	95	275	370
Long-term liabilities	—	—	—	—

(in thousands of dollars)	December 31, 2017			
	Fair Value Measurements Using			
Commodity Price Hedges	(Level 1)	(Level 2)	(Level 3)	Total
Current assets	$ —	$ 3,474	$ —	$ 3,474
Long-term assets	—	56	116	172
Current liabilities	—	28,946	7,763	36,709
Long-term liabilities	—	7,860	928	8,788

Table of Contents

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 December 31, 2018.

	Quantitative Information About Level 3 Fair Value Measurements			
Commodity Price Hedges	Fair Value (000's)	Valuation Technique	Unobservable Input	Range
Crude oil collars	$ 3,441	Use a discounted option model approach using inputs including interpolated volatilities for certain settlement months where market volatility quotes were unavailable for the option strike price	Market volatility quotes at the option strike for certain settlement months in 2019	$45.00 - $61.00 per barrel
Natural gas collars	$ (196)	Use a discounted option model approach using inputs including interpolated volatilities for certain settlement months where market volatility quotes were unavailable for the option strike price	Market volatility quotes at the option strike for certain settlement months in 2019	$2.55 - $3.41 per MMbtu

The following table presents the changes in the Level 3 financial instruments for the years ended December 31, 2018 and 2017:

(in thousands of dollars)	
Balance at December 31, 2016, net	$ (2,971)
Purchases	(1,236)
Settlements	1,606
Transfers to Level 2	—
Transfers to Level 3	(6,527)
Changes in fair value	553
Balance at December 31, 2017, net	$ (8,575)
Purchases	—
Settlements	5,573
Transfers to Level 2	958
Transfers to Level 3	—
Changes in fair value	5,289
Balance at December 31, 2018, net	$ 3,245

Changes in fair value of Level 3 instruments represent changes in gains and losses for the periods that are reported in in net gain (loss) on commodity derivatives on the Company's Consolidated Statement of Operations. 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. Transfers from Level 3 to Level 2 represent the Company's contracts for which observable forward curve pricing information has become readily available.

Table of Contents

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets are measured at fair value on a nonrecurring basis. These assets are not measured at fair value on any ongoing basis, but are subject to fair value adjustments in certain circumstances. These assets can include long- lived assets that have been reduced to fair value when they are held for sale, inventory and proved and unproved oil and gas properties that are written down to fair value when they are impaired.

Proved and Unproved oil and gas properties

During 2018, downward trends in commodity price levels of crude oil and natural gas in addition to significant revisions of our reserve volumes due to capital constraints provided indications of possible impairment of the Company's Western Anadarko Basin properties, located in western Oklahoma and the eastern portion of the Texas Panhandle, and the Company's Eastern Anadarko Basin properties, located in Oklahoma.

As a result of an assessment of recoverability considering undiscounted cash flows predicated on the commodity price environment at year-end 2018 and the development and operation of the proved Western Anadarko Basin and Eastern Anadarko Basin properties, the Company determined that the Western Anadarko Basin and Eastern Anadarko Basin properties were impaired and recognized impairment charges to reduce the carrying values of the Western Anadarko Basin and Eastern Anadarko Basin properties to their estimated fair values.

The Company calculated the fair values of the Western Anadarko Basin and Eastern Anadarko Basin proved developed properties under the income approach using a discounted cash flow model.

Significant Level 3 assumptions associated with the calculation of discounted future cash flows included commodity price outlooks set forth by management and outlooks for (i) production, (ii) production costs, (iii) G&A costs, (iv) capital expenditures, (v) income taxes and (vi) estimated proved, probable and possible reserves.

Commodity price outlooks were developed based on forward pricing as of December 31, 2018, and an assessment around open interest, trading volumes and assumed liquidity of futures contracts that serve as the basis for crude oil and natural gas pricing. The price deck used in the Company's impairment assessment is based on average forward pricing through 2021; prices after 2021 are inflated annually at 2.2%. The inflation estimate is based on economists' long-term estimates of inflation and is published in the Federal Reserve Bank of Philadelphia's Livingston Survey. To determine fair value, the expected future net cash flows were discounted using an estimated cost of capital for a market participant.

Write Down for Proved Properties (1)	As of December 31, 2018		
(in thousands of dollars)	Eastern Anadarko Basin	Western Anadarko Basin	Other
Carrying Value	$ 335,919	$ 1,209,791	$ —
Fair Value	74,952	150,033	4,852
Write Down	260,967	1,059,758	—

(1) Properties with fair values exceeding carrying value remain at carrying value.

The Western Anadarko Basin properties were valued by multiplying the year-end daily production amount from the properties by a selected valuation multiple derived from precedent transactions involving comparable properties. The estimated fair value of the proved developed properties was deducted from the total fair value of the Western Anadarko

Table of Contents

Basin properties calculated under the market approach; the residual amount was deemed to be the fair value of the proved undeveloped and unproved properties.

The Eastern Anadarko Basin properties were valued by multiplying the net acreage position held by the Company by a selected acreage multiple based on precedent transactions involving comparable acreage. The estimated fair value of the proved developed properties was deducted from the total fair value of the Eastern Anadarko Basin properties calculated under the market approach. The residual value was deemed to be the fair value of the proved undeveloped and unproved properties.

The market approach was used to determine the fair value of the proved undeveloped and unproved properties.

Write Down for Unproved Properties (1)	As of December 31, 2018		
(in thousands of dollars)	Eastern Anadarko Basin	Western Anadarko Basin	Other
Carrying Value	$ 35,177	$ 22,743	$ —
Fair Value	87,474	11,683	157
Write Down	—	11,060	—

(1) Properties with fair values exceeding carrying value remain at carrying value.

Given impairment indications under the recoverability test, the carrying values of the proved and unproved Western Anadarko Basin properties and proved Eastern Anadarko Basin properties were written down to their calculated fair values as of December 31, 2018. The total impairment charge of $1,332.0 million associated with the proved and unproved Western Anadarko Basin properties and proved Eastern Anadarko Basin properties is reported in Operating income (loss) in the accompanying consolidated statements of operations.

Fair Value of Financial Instruments

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

	December 31, 2018		December 31, 2017	
	Principal		Principal	
(in thousands of dollars)	Amount	Fair Value	Amount	Fair Value
Debt:				
Revolver	$ —	$ —	$ 211,000	$ 211,000
2022 Notes	409,148	63,254	409,148	305,404
2023 Notes	150,000	31,379	150,000	114,750
2023 First Lien Notes	450,000	396,167	—	—

The Revolver (as defined in Note 7) is categorized as Level 3 in the valuation hierarchy as the debt is not publicly traded and no observable market exists to determine the fair value; however, the carrying value of the Revolver approximates fair value, as it is subject to short-term floating interest rates that approximate the rates available to the Company for those periods.

The fair value of the 2022 Notes (as defined in Note 7) is based on pricing that is readily available in the public market. Accordingly, the 2022 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 fair value of the 2023 Notes (as defined in Note 7) 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 fair value of the 2023 First Lien Notes (as defined in Note 7) is based on indicative pricing that is available in the public market. Accordingly, the 2023 First Lien 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.

Table of Contents

Fair Value of Other Assets and Liabilities

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

10. Asset Retirement Obligations

A summary of the Company's Asset Retirement Obligations ("ARO") for the years ended December 31, 2018 and 2017 is as follows:

(in thousands of dollars)	2018	2017
ARO liability at beginning of year	$ 20,372	$ 20,058
Liabilities incurred	304	1,062
Accretion of ARO liability	1,066	960
Liabilities settled due to sale of related properties	(288)	(1,231)
Liabilities settled due to plugging and abandonment	(513)	(339)
Change in estimate	391	(138)
ARO liability at end of year	21,332	20,372
Less: Current portion of ARO at end of year	(900)	(720)
Total long-term ARO at end of year	$ 20,432	$ 19,652

11. Stock based Compensation

All share and weighted average fair value per share information presented has been recast to retrospectively adjust for the effects of the 1-for-20 Reverse Stock Split effective on September 7, 2018, as defined in Note 14, "Stockholders' and Mezzanine Equity".

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 December 31, 2018:

	JEH Units	Weighted Average Grant Date Fair Value per Share
Unvested at December 31, 2017	1,615	$ 300.00
Granted	1,515	300.00
Forfeited	(1,515)	300.00
Vested	(1,615)	300.00
Unvested at December 31, 2018	—	$ —

Stock compensation expense associated with the Management Units for the years ended December 31, 2018, 2017 and 2016 was $0.1 million, $0.6 million, and $1.2 million, respectively, and is included in general and administrative

Table of Contents

expenses on the Company's Consolidated Statement of Operations. The weighted average grant date fair value of management units was $300.00 per share for the years ended December 31, 2018 and 2017. As of December 31, 2018, there were no outstanding Management Units and, therefore, no unrecognized expense associated with the Management Units.

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 restated on May 4, 2016 following approval by the Company's stockholders, the Company has reserved a total of 425,265 shares of Class A common stock for non-employee director, consultant, and employee stock-based compensation awards, as adjusted for the effects of the Special Stock Dividend, the preferred stock dividends paid in shares and the Reverse Stock Split, as described in Note 14 "Stockholders' and Mezzanine Equity".

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 2016, 2017 and 2018. During 2016 and 2017, 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 December 31, 2018:

	Restricted Stock Unit Awards	Weighted Average Grant Date Fair Value per Share
Unvested at December 31, 2017	137,949	$ 55.61
Adjustment (1)	2,559	—
Granted	179,946	9.16
Forfeited	(63,175)	47.02
Vested	(52,635)	66.62
Unvested at December 31, 2018	204,644	$ 13.84

(1) Increase of 0.019796 units for each unvested restricted stock unit awards at the time of the Company's February 15, 2018 preferred stock dividend paid entirely in shares of the Company's Class A common stock, as described in Note 14 "Stockholders' and Mezzanine Equity," in accordance with the terms of the original awards.

Stock compensation expense associated with the employee restricted stock unit awards for the years ended December 31, 2018, 2017, and 2016 was $1.4 million, $3.8 million, and $3.0 million, respectively, and is included in general and administrative expenses on the Company's Consolidated Statement of Operations. The fair value of restricted stock unit awards vested for the years ended December 31, 2018, 2017 and 2016 was $0.8 million, $1.5 million and $0.8 million, respectively. The weighted average grant date fair value of restricted stock units was $9.16 per share, $46.35 per share, and $73.46 per share for the years ended December 31, 2018, 2017, and 2016, respectively.

Unrecognized expense as of December 31, 2018 for all outstanding restricted stock unit awards was $2.8 million and will be recognized over a weighted-average remaining period of 1.9 years.

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.

Table of Contents

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 table summarizes information related to the total number of performance share units awarded to the senior management team as of December 31, 2018:

	Performance Share Unit Awards	Weighted Average Grant Date Fair Value per Share
Unvested at December 31, 2017	47,851	$ 66.79
Adjustment (1)	946	—
Granted	40,940	26.00
Forfeited	(1,881)	82.63
Cancelled	(40,940)	62.89
Vested	(43,998)	29.94
Unvested at December 31, 2018	2,918	$ 41.98

(1) Increase of 0.019796 units for each unvested restricted stock unit awards at the time of the Company's February 15, 2018 preferred stock dividend paid entirely in shares of the Company's Class A common stock, as described in Note 14 "Stockholders' and Mezzanine Equity," in accordance with the terms of the original awards.

The vesting of the awards issued to certain members of our senior management who departed on April 17, 2018 and November 2, 2018, accelerated at 100% for the unvested performance share units at the time of departure in accordance with the terms of the award.

At the time the performance share units vest, the results of the Company's total share return relative to the industry peer group must be certified by the compensation committee of the board of directors before the corresponding shares of Class A common stock are issued. As of December 31, 2018, 2,999 performance share units that vested during 2018 were awaiting certification by the compensation committee. Based upon the Company's total share return relative to the industry peer group, no shares of Class A common stock will be issued for the outstanding vested units awaiting certification.

The estimated fair value of performance share units vested during the year ended December 31, 2018 was $0.4 million. The estimated fair value of performance share units vested during the year ended December 31, 2017 was $0.2 million, which were distributed to recipients during the first quarter of 2018. The estimated fair value of performance share units vested during the year ended December 31, 2016 was $0.8 million, the shares of which were distributed to recipients during the first quarter of 2017.

Stock compensation expense associated with the performance share unit awards for the years ended December 31, 2018, 2017, and 2016 was an offset to expense of $0.2 million, and an expense of $1.5 million, and $2.7 million, respectively, and is included in general and administrative expenses on the Company's Consolidated Statement of Operations. The weighted average grant date fair value of performance share unit awards was $26.00 per share, $44.80 per share, and $87.50 per share for the years ended December 31, 2018, 2017, and 2016, respectively. Unrecognized expense as of December 31, 2018 for all outstanding performance share unit awards was less than $0.1 million and will be recognized over a weighted-average remaining period of 1.0 years.

Performance Unit Awards

The Company has outstanding performance unit awards, granted in 2016 and 2017, to certain members of the senior management team of the Company under the LTIP. References to performance unit awards in filings prior to the second quarter of 2016 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 $0.00 to $200.00 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 re-measured 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 at award using a Monte Carlo simulation model, as of the grant date, which resulted in an estimated final value upon vesting of $0.1 million and less than $0.1 million for the awards made in 2017 and 2016, respectively, as adjusted for forfeitures. The fair value measured as of December 31, 2017 was $0.1 million and $0.1 million for the awards made in 2017 and 2016, respectively. The fair value measured as of December 31, 2018 was less than $0.1 million.

The vesting of the awards issued to certain members of our senior management who departed on April 17, 2018 and November 2, 2018 accelerated for the unvested performance unit awards at the time of departure in accordance with the terms of the award. Such awards vested at $100.00 per performance unit.

Stock compensation expense associated with the performance unit awards was an expense of $2.1 million, an income position of $0.2 million and expense of $0.3 million for the years ended December 31, 2018, 2017 and 2016, respectively, and is included in general and administrative expenses on the Company's Consolidated Statement of Operations. As of December 31, 2018, $0.0 million of unrecognized compensation expense related to all the performance unit awards, subject to re-measurement 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 remaining period of 1.0 years.

Restricted Stock Awards

The Company has outstanding restricted stock awards granted to the non-employee members of the Board 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.

The following table summarizes information related to the total value of the awards to the Board as of December 31, 2018:

	Restricted Stock Awards	Weighted Average Grant Date Fair Value per Share
Unvested at December 31, 2017	9,370	$ 43.22
Adjustment (1)	123	—
Granted	3,123	23.40
Cancelled	(3,123)	(43.23)
Vested	(9,493)	(36.14)
Unvested at December 31, 2018	—	$ —

(1) Increase of 0.019796 units for each unvested restricted stock unit awards at the time of the Company's February 15, 2018 preferred stock dividend paid entirely in shares of the Company's Class A common stock, as described in Note 14 "Stockholders' and Mezzanine Equity," in accordance with the terms of the original awards.

Stock compensation expense associated with awards to the members of the Board for the years ended December 31, 2018, 2017 and 2016 was $0.1 million, $0.4 million, and $0.6 million, respectively, and is included in general and administrative expenses on the Company's Consolidated Statement of Operations. The fair value of restricted stock awards vested for the years ended December 31, 2018, 2017 and 2016 was $0.2 million, $0.3 million and $0.3 million, respectively. The weighted average grant date fair value of restricted stock awards was $23.40 per share, $45.00 per share, and $73.60 per share for the years ended December 31, 2018, 2017, and 2016. There was no unrecognized expense as of December 31, 2018.

Table of Contents

Forfeitures of stock-based awards are are recorded when they occur. For the years ended December 31, 2018, 2017, and 2016, the Company had an associated tax benefit of $0.7 million, $1.6 million, and $1.4 million, respectively, related to all stock-based compensation, calculated at the federal statutory rate after adjusting for the non-controlling interest.

12. Benefit Plans

The Company maintains a tax-qualified 401(k) savings plan (the “Plan”) for the benefit of employees. The Plan is a defined contribution plan and the Company may match a portion of employee contributions to the Plan.

In addition, since 2013, the Company has maintained a non-qualified deferred compensation plan for the benefit of key employees. The non-qualified deferred compensation plan is an unfunded, account-based plan under which key employees of the Company may elect to defer a portion of their base salary and/or bonus. On December 12, 2018, the Compensation Committee of the Board of Directors of the Company approved the termination of the Plan as part of its year-end review of the Company’s compensation programs, subject to further approval of definitive documentation. For the years ended December 31, 2018, 2017, and 2016, our total expense relating to these plans was $0.5 million, $0.4 million, and $0.4 million, respectively.

13. 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.

On December 22, 2017, the US Congress enacted the Tax Cuts and Jobs Act (the “Tax Reform Legislation”), which made significant changes to US federal income tax law, including a reduction of the federal corporate tax rate to 21% effective January 1, 2018. We are required to recognize the effect of a rate change on deferred tax assets and liabilities in the period in which the tax rate change is enacted. Therefore, the rate change enacted by the Tax Reform Legislation resulted in the recognition of a tax benefit along with a benefit from the reduction of the liability under the Tax Receivable Agreement during the year ended December 31, 2017.

The Tax Reform Legislation is a comprehensive bill containing other provisions, such as limitations on the deductibility of interest expense and certain executive compensation, none of which are expected to lead to a material current tax liability at this time. The ultimate impact of Tax Reform Legislation may differ from our estimates due to changes in interpretations and assumptions made by us, as well as additional regulatory guidance that may be issued. The Company has not made any further adjustments to its deferred tax assets and liabilities as a direct result of Tax Reform Legislation since recording the effects of the tax rate change during the year ended December 31, 2017.

The following table summarizes the tax provision for the years ended December 31, 2018, 2017, and 2016:

	Year Ended December 31,		
(in thousands of dollars)	2018	2017	2016
Current tax expense (benefit):			
Federal	$ (5)	$ (3,555)	$ 3,758

State	—	(30)	223
Total current expense (benefit)	(5)	(3,585)	3,981
Deferred tax expense (benefit):			
Federal	(60,420)	(46,917)	(27,245)
State	(1,416)	(165)	(522)
Total deferred expense (benefit)	(61,836)	(47,082)	(27,767)
Total tax expense (benefit)	$ (61,841)	$ (50,667)	$ (23,786)
Tax benefit attributable to controlling interests	(61,713)	(50,422)	(23,263)
Tax benefit attributable to non-controlling interests	(128)	(245)	(523)
Total income tax expense (benefit)	$ (61,841)	$ (50,667)	$ (23,786)

Table of Contents

A reconciliation of the Company's provision for income taxes as reported and the amount computed by multiplying income before taxes, less non controlling interest, by the U.S. federal statutory rate of 21% for the year ended December 31, 2018 and 35% for the years ended December 31, 2017 and 2016:

(in thousands of dollars)	2018	2017	2016
Provision calculated at federal statutory income tax rate:			
Net income before taxes	$ (1,408,535)	$ (229,490)	$ (108,591)
Statutory rate	21 %	35 %	35 %
Income tax expense (benefit) computed at statutory rate	$ (295,792)	$ (80,322)	$ (38,007)
Less: Non-controlling interests	11,714	27,152	14,972
Income tax expense (benefit) attributable to controlling interests	(284,078)	(53,170)	(23,035)
State and local income taxes, net of federal benefit	(34,127)	(4,692)	(622)
IRC Section 382 limitation	—	41,653	—
Reduction of TRA liability	(11,199)	—	(282)
Change in enacted rate	—	(38,040)	—
Change in valuation allowance	268,098	4,302	950
Other	(407)	(475)	(274)
Tax expense (benefit) attributable to controlling interests	(61,713)	(50,422)	(23,263)
Tax expense attributable to non-controlling interests	(128)	(245)	(523)
Total income tax expense (benefit)	$ (61,841)	$ (50,667)	$ (23,786)

The Company is subject to federal, state, and local income and franchise taxes. As such, deferred income taxes result from temporary differences between the carrying amounts of assets and liabilities of the Company for financial reporting purposes and the amounts used for income tax purposes. Deferred tax assets and liabilities are measured using enacted tax rates in effect in the years in which those temporary differences are expected to reverse.

In 2017, the United States enacted legislation that reduced the federal corporate tax rate from 35% to 21% for tax years beginning on or after January 1, 2018. The Company was required to recognize the effect of this rate change on its deferred tax assets and liabilities in the period the tax rate change is enacted. During the year ended December 31, 2017, we recorded a tax benefit of $17.2 million, net of valuation allowance, as a result of revaluing our deferred tax assets and liabilities at the newly enacted rate. During the year ended December 31, 2017, the Company also recognized non-taxable income from the reduction of the liability under the Tax Receivable Agreement as a result of remeasuring the liability to reflect the revised federal statutory rate that had an impact on the effective rate of $20.8 million.

Table of Contents

Significant components of the Company’s deferred tax assets and deferred tax liabilities consisted of the following:

	As of December 31,	
(in thousands of dollars)	2018	2017
Deferred tax assets		
Investment in consolidated subsidiary JEH	$ 129,437	$ —
Net operating loss	78,372	13,381
Section 754 election tax basis adjustment	83,764	78,623
Other deferred tax asset	2,438	220
Total deferred tax assets	294,011	92,224
Deferred tax liabilities		
Investment in consolidated subsidiary JEH	—	93,974
Noncurrent state deferred tax liability	—	2,281
Total deferred tax liabilities	—	96,255
Net deferred tax assets (liabilities)	294,011	(4,031)
Valuation allowance	(293,882)	(10,250)
Net deferred tax assets (liabilities)	$ 129	$ (14,281)

Internal Revenue Code ("IRC") Section 382 limits a corporation’s utilization of federal net operating loss carryforwards and certain other tax attributes on an annual basis following an ownership change of the corporation. The Company has a federal net operating loss and other carry-forward amounts totaling $410.6 million, tax credit carry-forwards of $0.6 million, and state net operating loss carry-forward of $216.3 million. This includes net operating losses generated in 2018. Federal net operating losses generated in 2018 and future years will have an indefinite carryforward as a result of Tax Reform Legislation and will be available to offset 80% of taxable income generated in a given year. The federal and state net operating carryforwards generated before Tax Reform Legislation are set to expire between 2033 and 2037. The tax benefits of carryforwards are recorded as an asset to the extent that management assesses the utilization of such carryforwards to be more likely than not. When the future utilization of some portion of the carryforwards is determined not to be more likely than not, a valuation allowance is provided to reduce the recorded tax benefits from such assets. As of December 31, 2018 and 2017, we had a valuation allowance of $293.9 million and $10.2 million, respectively as a result of management’s assessment of the realizability of federal and state deferred tax assets. 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.

The Company experienced ownership changes within the meaning of IRC Section 382 during 2017 and 2015 that subject a portion of its federal net operating loss carryforwards to IRC Section 382 limitations. The Company estimates that the IRC Section 382 limitation that applies to the Company’s 2017 ownership change will result in a permanent loss of federal and state deferred tax assets totaling $13.8 net operating loss carryforwards and other tax attributes, as measured at the 21% enacted rate and adjusted for the modified loss carryforward provisions of Tax Reform Legislation. The reduction in state net operating loss carryforwards was off-set by a corresponding $2.4 million adjustment to the valuation allowance.

Separate federal and state income tax returns are filed for Jones Energy, Inc. and Jones Energy Holdings, LLC. JEH’s Texas franchise tax returns are subject to audit for 2013 through 2018. The tax years 2015 through 2018 remain open to examination by the major taxing jurisdictions to which the Company is subject, however net operating losses originating in prior years are subject to examination when utilized. The Company does not have any income tax returns under audit by the Internal Revenue Service or any state jurisdiction.

Accounting for uncertainty in income taxes prescribes a recognition threshold and measurement methodology for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. As of December 31, 2018, 2017 and 2016 there was no material liability or expense for the periods then ended recorded for payments of interest and penalties associated with uncertain tax positions or material unrecognized tax positions and the Company’s unrecognized tax benefits were not material.

Tax Receivable Agreement

In connection with the IPO, the Company entered into a Tax Receivable Agreement (the “TRA”) which obligates the Company to make payments to certain current and former owners equal to 85% of the applicable cash savings that the Company realizes as a result of tax attributes arising from exchanges of JEH Units and shares of the Company’s Class B

Table of Contents

common stock held by those owners for shares of the Company's Class A common stock. The Company will retain the benefit of the remaining 15% of these tax savings. At the time of an exchange, the company records a liability to reflect the future payments under the TRA.

The TRA liability is recorded based upon the projected tax savings at the time of an exchange. As a result of the tax reform legislation, the amount of the TRA liability was remeasured to reflect the reduction of the federal corporate tax rate from 35% to 21%. During the year ended December 31, 2017 we recorded a benefit for the reduction of the TRA liability of $59.5 million as a result of the newly enacted rate. The amount is included in other income (expense) on the Company's Consolidated Statement of Operations.

The actual amount and timing of payments to be made under the TRA will depend upon a number of factors, including the amount and timing of taxable income generated in the future, changes in future tax rates, the use of loss carryovers, and the portion of the Company's payments under the TRA constituting imputed interest. As of December 31, 2018 and December 31, 2017, the Company had a gross TRA liability of $77.4 million and $69.9 million, respectively. As a result of the valuation allowance recorded against its deferred tax assets associated with prior exchanges, the TRA liability was reduced, as the payment of the TRA liability is dependent upon the realizability of the associated deferred tax assets. As of December 31, 2018 and 2017, the amount of the TRA liability was reduced by $77.4 million and $8.7 million, respectively, as a result of the valuation allowance recorded against the Company's deferred tax assets. 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.

As of December 31, 2018, the Company had no TRA liability, net, because the associated deferred tax assets were fully offset by the valuation allowance recorded against them and therefore, the TRA liability was reduced to zero.

As of December 31, 2017 the Company had recorded a net $61.2 million for the estimated payments that to the Class B shareholders who have exchanged shares, of which $1.6 million was recorded within other current liabilities on the Company's Consolidated Balance Sheet, after adjusting for the TRA liability reduction. As of December 31, 2017 there were corresponding deferred tax assets, net of valuation allowance, of $72.3 million as a result of the increase in tax basis arising from such exchanges.

The Company made a payment of $1.6 million of the TRA liability with respect to cash savings that the Company realized on its 2016 tax return as a result of tax attributes arising from prior exchanges in the first quarter of 2018. The Company did not realize cash savings on its 2017 tax return as a result of tax attributes arising from prior exchanges, and therefore did not make a payment under the TRA for the 2017 tax year. The Company does not anticipate it will realize cash savings on its 2018 tax return as a result of tax attributes arising from prior exchanges, and therefore does not anticipate a payment under the TRA for the 2018 tax year.

Cash Tax Distributions

The holders of JEH Units, including the Company, 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.

JEH does not project to generate taxable income for the 2019 tax year and did not generate taxable income for the 2018 tax year and therefore did not make quarterly tax distributions to its unitholders during the year ended December 31, 2018 or during 2017 with respect to the 2018 or 2017 tax years.

A Special Committee of the Board comprised solely of directors who did not have a direct or indirect interest in such distribution approved, and JEH made, aggregate cash tax distributions during 2017 and 2016 of $1.7 million and $41.0 million, respectively, (including distributions to us) to its unitholders towards its total 2016 projected tax distribution obligation. Distributions during 2017 were made pro-rata to all members of JEH, and included a $1.1 million payment to the Company and a $0.6 million payment to JEH unitholders other than the Company. Distributions during 2016 were made pro-rata to all members of JEH, and included a $23.7 million payment to the Company and a $17.3 million payment to Class B shareholders. The 2016 tax distributions are the result of taxable income generated by JEH's operations and debt extinguishment. All tax distributions were paid as a result of JEH's 2016 taxable income.

14. Stockholders' and Mezzanine 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.

The Company has classified the Series A preferred stock as mezzanine equity based upon the terms and conditions that contain various redemption and conversion features. For a description of these features, please see below under "—Offering of 8.0% Series A Perpetual Convertible Preferred Stock."

Equity Distribution Agreement

On May 24, 2016, the Company and JEH 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.

The Company used the net proceeds from sales under the Equity Distribution Agreement for general corporate purposes. As of December 31, 2018, approximately $62.2 million in aggregate offering proceeds remained available to be issued and sold under the Equity Distribution Agreement.

Mezzanine Equity

On August 26, 2016, the Company issued 1,840,000 shares of Series A preferred stock pursuant to an underwritten public offering for total net proceeds (after underwriters' discounts and commissions but before expenses) of $88.3

million.

Holders of Series A preferred stock are entitled to receive, when as and if declared by the Board, cumulative dividends at the rate of 8.0% per annum (the “dividend rate”) per share on the $50.00 liquidation preference per share of the Series A preferred stock, payable quarterly in arrears on February 15, May 15, August 15 and November 15 of each year, beginning on November 15, 2016. Dividends may be paid in cash or, subject to certain limitations, in Class A common stock, or a combination thereof.

Under the terms of the Series A preferred stock, the Company’s ability to declare or pay dividends or make distributions on, or purchase, redeem or otherwise acquire for consideration, shares of the Company’s Class A common stock, or any junior stock or parity stock currently outstanding or issued in the future, will be subject to certain restrictions in the event that the Company does not pay in full or declare and set aside for payment in full all accrued and unpaid dividends on the Series A preferred stock (including certain unpaid excess cash payment amounts excused from payment as a dividend due to restrictions in credit facilities or other indebtedness or legal requirements (“Unpaid Excess Cash Payment Amounts”)).

Each share of Series A preferred stock has a liquidation preference of $50.00 per share and is convertible, at the holder’s option at any time, into approximately 0.8534 shares of Class A common stock after adjusting the conversion ratio for the effects of the Special Stock Dividend and the Reverse Stock Split, as defined in Note 14, “Stockholders’ and Mezzanine Equity”, (which is equivalent to a conversion price of approximately $58.59 per share after such adjustments), subject to specified further adjustments and limitations as set forth in the certificate of designations for the

Table of Contents

Series A preferred stock. Based on the adjusted conversion rate and the full exercise of the Preferred Stock Underwriters' over-allotment option, approximately 1.6 million shares of Class A common stock would be issuable upon conversion of all the Series A preferred stock.

On or after August 15, 2021, the Company may, at its option, give notice of its election to cause all outstanding shares of Series A preferred stock to be automatically converted into shares of Class A common stock at the conversion rate, if the closing sale price of the Class A common stock equals or exceeds 175% of the conversion price for at least 20 trading days in a period of 30 consecutive trading days.

On August 15, 2024 (the "designated redemption date"), each holder of Series A preferred stock may require us to redeem any or all Series A preferred stock held by such holder outstanding on the designated redemption date at a redemption price equal to a liquidation preference of $50.00 per share plus all accrued dividends on the shares up to but excluding the designated redemption date that have not been paid plus any Unpaid Excess Cash Payment Amounts (the "redemption price"). At our option, the redemption price may be paid in cash or, subject to certain limitations, in Class A common stock, or a combination thereof.

Except as required by law or the Company's certificate of incorporation, which includes the certificate of designations for the Series A preferred stock, the holders of Series A preferred stock have no voting rights (other than with respect to certain matters regarding the Series A preferred stock or when dividends payable on the Series A preferred stock have not been paid for an aggregate of six quarterly dividend periods, or more, whether or not consecutive, as provided in the certificate of designations for the Series A preferred stock).

The Series A preferred stock is classified as mezzanine equity on the Company's Consolidated Balance Sheet and is not listed on a national stock exchange.

A summary of the Company's Mezzanine equity for the year ended December 31, 2018 is as follows:

(in thousands of dollars)	
Mezzanine equity at December 31, 2017	$ 89,539
Accrued dividends on preferred stock	5,395
Accretion on preferred stock	502
Change in estimate due to settlements	(1,717)
Mezzanine equity at December 31, 2018	$ 93,719

Reverse Stock Split

On March 23, 2018, the NYSE notified the Company that it was non-compliant with certain continued listing standards because the price of the Company's Class A common stock over a period of 30 consecutive trading days had fallen below $1.00 per share, which is the minimum average closing price per share required to maintain a listing on the NYSE. The Company had a six-month cure period during which it could regain compliance.

The Company notified the NYSE that it intended to cure the price deficiency by proposing a reverse stock split for approval by the Company's stockholders. At the Company's Annual Meeting of Stockholders held on May 22, 2018, the Company's stockholders approved the voting item that granted the Board discretionary authority to effect an amendment to the Company's Amended and Restated Certificate of Incorporation to effect a reverse stock split of the Common Stock (as defined below), at a ratio between 1-for-5 and 1-for-20, with such ratio to be determined by the Board in its sole discretion.

On August 17, 2018, the Board approved a reverse stock split for the Company's issued and outstanding Class A and Class B common stock (together, the "Common Stock") of 1-for-20 (the "Reverse Stock Split"), effective after market close on September 7, 2018.

In connection with the Reverse Stock Split, the Company filed an amendment to its Amended and Restated Certificate of Incorporation with the Secretary of State of the State of Delaware (the "Amendment"). The Amendment, effective as of 5:00 p.m., New York City time, on September 7, 2018, converted each 20 issued and outstanding share of Class A common stock into one share of Class A common stock and each 20 issued and outstanding shares of Class B common stock into one share of Class B common stock. A Certificate of Correction to the Amendment (the "Certificate of

Table of Contents

Correction") correcting the cash payout process for fractional shares resulting from the Reverse Stock Split was filed with the Secretary of State of the State of Delaware on September 10, 2018. Pursuant to the Certificate of Correction, any fraction of a share of Common Stock that would otherwise have resulted from the Reverse Stock Split were settled by cash payment, equal to the fraction of one share of Common Stock multiplied by the average of the high and low trading prices of the Class A common stock on the NYSE during regular trading hours for the five trading days immediately preceding September 7, 2018.

The Reverse Stock Split did not affect any record holder's percentage ownership interest in the Company, except for de minimis changes as a result of the elimination of fractional shares. The Reverse Stock Split reduced the number of shares of Class A common stock outstanding from 98,039,826 (excluding treasury shares) to 4,901,986 and the number of shares of Class B common stock outstanding from 4,825,038 to 241,251. The Reverse Stock Split did not affect the authorized number of shares of Class A common stock or Class B common stock. Presentation has been adjusted as it relates to prior periods to reflect the 1-for-20 reverse stock split discussed herein.

The Class A common stock began trading on a reverse split-adjusted basis on the NYSE at the opening of trading on September 10, 2018. The Class A common stock continues trading on the NYSE under the symbol "JONE" with a new CUSIP number (48019R 306).

All outstanding equity awards, pursuant to the various instruments governing them, were adjusted immediately prior to the Reverse Stock Split by dividing the number of shares of Class A common stock into which such equity awards were exercisable or convertible by 20. In connection with such proportionate adjustments, the number of shares of Class A common stock issuable upon exercise or conversion of outstanding equity awards was rounded down to the nearest whole share.

The Reverse Stock Split did not affect the number of authorized or outstanding shares of the Company's Series A preferred stock or the dividend rate per share of any outstanding shares of Series A preferred stock. In accordance with the Certificate of Designations governing the Series A preferred stock, the conversion rate of the Series A preferred stock has been adjusted to reflect the Reverse Stock Split to equal 0.8534. The conversion ratio is currently equal to 1.4796 following the issuance of a fundamental change notice in conjunction with the delisting of the Company's Class A common stock from the New York Stock Exchange, which gave holders of the preferred stock special rights to convert shares of preferred stock to class A common stock at a premium to the existing conversion rate until March 31, 2019.

On September 21, 2018, the Company received notice from the NYSE that the Company had regained compliance with the NYSE's continued listing standards. As a result of the Reverse Stock Split, the Company regained compliance as of market close September 21, 2018, because the closing price per share of the Company's Class A common stock was above $1.00 per share and was on average above $1.00 for the 30 trading days preceding September 21, 2018. The shares of Class A common stock continued trading on the NYSE without interruption.

Move from NYSE to OTCQX

Jones Energy, Inc.'s Class A common stock was listed on the New York Stock Exchange ("NYSE") under the symbol "JONE" between July 2013 and November 2018. The Class A shares transitioned from the NYSE to trading on the OTCQX on November 27, 2018 retaining its ticker symbol "JONE".

Preferred Stock Dividends

On January 19, 2017, the Board declared a quarterly cash dividend per share equal to 8.0% based on the liquidation preference of $50.00 per share on an annualized basis, or $1.00 per share, on the Series A preferred stock. This dividend is for the period beginning on the last payment date of November 15, 2016 through February 14, 2017 and was paid in cash on February 15, 2017 to shareholders of record as of February 1, 2017.

On April 17, 2017, the Board declared a quarterly dividend per share equal to 8.0% based on the liquidation preference of $50.00 per share on an annualized basis, or $1.00 per share, on the Series A preferred stock. On May 15, 2017, the dividend was paid in a combination of cash and the Company's Class A common stock, with the cash component equal to $0.83 per share and the stock component equal to $0.17 per share. The price per share of the Class A common stock used to determine the number of shares issued was equal to 95% of the average volume-weighted average price per share for each day during the five-consecutive day trading period ending immediately prior to the payment date. This dividend was for the period beginning on the last payment date of February 15, 2017 through May 14, 2017 to shareholders of record as of May 1, 2017.

On July 13, 2017, the Board declared a quarterly dividend per share equal to 8.0% based on the liquidation preference of $50.00 per share on an annualized basis, or $1.00 per share, on the Series A preferred stock. On August 15, 2017, the dividend was paid entirely in shares of Class A common stock. The price per share of the Class A common stock used to determine the number of shares issued was equal to 95% of the average volume-weighted average price per share for each day during the five-consecutive day trading period ending immediately prior to the payment date. This dividend was for the period beginning on the last payment date of May 15, 2017 through August 14, 2017 to shareholders of record as of August 1, 2017.

On October 9, 2017, the Board declared a quarterly dividend per share equal to 8.0% based on the liquidation preference of $50.00 per share on an annualized basis, or $1.00 per share, on the Series A preferred stock. On November 15, 2017, the dividend was paid entirely in shares of Class A common stock. The price per share of the Class A common stock used to determine the number of shares issued will equal 95% of the average volume-weighted average price per share for each day during the five-consecutive day trading period ending immediately prior to the payment date. This dividend was for the period beginning on the last payment date of August 15, 2017 through November 14, 2017 to shareholders of record as of November 1, 2017

On January 11, 2018, the Board declared a quarterly dividend per share equal to 8.0% based on the liquidation preference of $50.00 per share on an annualized basis, or $1.00 per share, on the Series A preferred stock. On February 15, 2018, the dividend was paid entirely in shares of Class A common stock. The price per share of the Class A common stock used to determine the number of shares issued was equal to 95% of the average volume-weighted average price per share for each day during the five-consecutive day trading period ending immediately prior to the payment date This dividend was for the period beginning on the last payment date of November 15, 2017 through February 14, 2018 to shareholders of record as of February 1, 2018.

On April 17, 2018, the Board declared a contingent quarterly dividend per share equal to 8.0% based on the liquidation preference of $50.00 per share on an annualized basis, or $1.00 per share, on the Series A preferred stock. However, the contingently declared payment was not ultimately paid as the Company was prohibited from paying cash dividends on the Series A preferred stock under the terms of its indebtedness. In order for the Company to pay the dividend in full in shares of Class A common stock, the average of the daily volume weighted average price per share of Class A Common Stock for each day during the five consecutive day trading period ending on, May 14, 2018 (the “Dividend Valuation Price”), was required to be at or above $15.20, as adjusted for the effects of the Reverse Stock Split (the “Floor Price”). The Dividend Valuation Price did not meet the Floor Price. The right for holders of Series A preferred stock to receive this dividend has been accrued.

On July 17, 2018, the Board declared a contingent quarterly dividend per share equal to 8.0% based on the liquidation preference of $50.00 per share on an annualized basis, or $1.00 per share, on the Series A preferred stock. However, the contingently declared payment was not ultimately paid as the Company was prohibited from paying cash dividends on the Series A preferred stock under the terms of its indebtedness. In order for the Company to pay the dividend in full in shares of Class A common stock, the Dividend Valuation Price, was required to be at or above the Floor Price, as adjusted for the effects of the Reverse Stock Split. The Dividend Valuation Price did not meet the Floor Price. The right for holders of Series A preferred stock to receive this dividend has been accrued.

On October 15, 2018, the Board declared a contingent quarterly dividend per share equal to 8.0% based on the liquidation preference of $50.00 per share on an annualized basis, or $1.00 per share, on the Series A preferred stock. However, the contingently declared payment was not ultimately paid as the Company was prohibited from paying cash dividends on the Series A preferred stock under the terms of its indebtedness. In order for the Company to pay the dividend in full in shares of Class A common stock, the Dividend Valuation Price, was required to be at or above the Floor Price, as adjusted for the effects of the Reverse Stock Split. The Dividend Valuation Price did not meet the Floor Price. The right for holders of Series A preferred stock to receive this dividend has been accrued.

As of December 31, 2018, the Company had $6.3 million of cumulative dividends in arrears on the Series A preferred stock, which related to the scheduled May 15, 2018, August 15, 2018 and November 15, 2018 dividends that were not paid.

Table of Contents

On January 16, 2019, the Board declared a contingent dividend per share equal to 8.0% based on the liquidation preference of $50.00 per share on an annualized basis, or $1.00 per share, on the Series A preferred stock. See Note 18 "Subsequent Events," in the Notes to Consolidated Financial Statements for further discussion.

Special Stock Dividend

On March 31, 2017, the Company paid a stock dividend (the "Special Stock Dividend") of 0.087423 shares of the Class A common stock (prior to adjustment for the effects of the Reverse Stock Split) to holders of record as of March 15, 2017. From time-to-time, JEH makes cash distributions to the holders of JEH Units to cover tax obligations that may occur as a result of any net taxable income of JEH allocable to holders of JEH Units. As a holder of JEH Units, the Company has received such cash distributions from JEH in excess of the amount required to satisfy the Company's associated tax obligations. As a result, the Company used the excess cash of approximately $17.5 million in the aggregate to acquire newly-issued JEH Units from JEH.

The Special Stock Dividend was distributed in order to equalize the number of shares of Class A common stock outstanding to the number of JEH Units held by the Company, and the aggregate number of shares of Class A common stock issued in the Special Stock Dividend equaled the number of additional JEH Units the Company purchased from JEH. The Company purchased 249,996 JEH Units, as adjusted for the effects of the Reverse Stock Split, at a price of $70.00 per share, which is the volume weighted average price per share of the Class A common stock for the five trading days ended February 28, 2017. Immaterial cash payments were made in lieu of fractional shares. The comparative earnings per share information has been recast to retrospectively adjust for the effects of the Special Stock Dividend.

15. 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 the Series A preferred stock and from stock awards that have been granted to directors and employees. Awards of non-vested 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 year ended December 31, 2018, 204,615 restricted stock units, and 5,966 performance share units, and 2,669,906 shares from the convertible Class A preferred stock, as adjusted for the effects of the Reverse Stock Split, were excluded from the calculation as they would have had an anti-dilutive effect. For the year ended December 31, 2017, 138,136 restricted stock units, and 62,541 performance share units, and 1,570,279 shares from the convertible Class A preferred stock, as adjusted for the effects of the Reverse Stock Split, were excluded from the calculation as they would have had an anti-dilutive effect. For the year ended December 31, 2016, 67,954 restricted stock units, 56,285 performance share units, and 1,570,283 shares from the convertible Class A preferred stock, as adjusted for the effects of the Reverse Stock Split, were excluded from the calculation as they would have had an anti-dilutive effect.

Table of Contents

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 periods presented:

Earnings per Share

(in thousands, except per share data)	Year Ended December 31, 2018	2017 (1)	2016 (1)
Income (numerator):			
Net income (loss) attributable to controlling interests	$ (1,291,039)	$ (101,492)	$ (42,552)
Less: Dividends and accretion on preferred stock	(7,737)	(7,924)	(2,669)
Net income (loss) attributable to common shareholder	$ (1,298,776)	$ (109,416)	$ (45,221)
Weighted-average shares (denominator):			
Weighted-average number of shares of Class A common stock - basic	4,776	3,621	2,175
Weighted-average number of shares of Class A common stock - diluted	4,776	3,621	2,175
Earnings (loss) per share:			
Basic - Net income (loss) attributable to common shareholders	$ (271.94)	$ (30.22)	$ (20.79)
Diluted - Net income (loss) attributable to common shareholders	$ (271.94)	$ (30.22)	$ (20.79)

(1) All share and earnings per share information presented has been recast to retrospectively adjust for the effects of the Special Stock Dividend distributed on March 31, 2017 and the Reverse Stock Split effective on September 7, 2018, as defined in Note 14, “Stockholders’ and Mezzanine Equity”.

16. Related Parties

Related Party Transactions

Transactions with Our Executive Officers, Directors and 5% Stockholders

Monarch Natural Gas Holdings, LLC Natural Gas Sale and Purchase Agreement

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. 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 $15.0 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. During the years ended December 31, 2018, 2017 and 2016, the Company amortized $1.6 million, $1.9 million, and $2.4 million, respectively, of the deferred revenue balance. This revenue is recorded in Other revenues on the Company's Consolidated Statement of Operations.

Following the issuance of $15.0 million Monarch equity interests to JEH, JEH assigned $2.4 million of the equity interests to Jonny Jones, the Company's Chairman of the Board, and reserved $2.6 million of the equity interests for future distribution through an incentive plan to certain of the Company's officers. The remaining $10.0 million of Monarch equity interests was distributed to certain of the Class B shareholders, which included, among others, Metalmark Capital, the Jones family entities, and certain of the Company's officers and directors, including Jonny Jones. As of December 31, 2018, equity interests in Monarch of $0.1 million are included in Other assets on the Company's Consolidated Balance Sheet. During the years ended December 31, 2018, 2017 and 2016, equity interests of $0.3 million, $0.3 million, and $0.6 million, respectively, were distributed to management under the incentive plan. The Company recognized expense of $0.1 million, $0.4 million, and $0.5 million during the years ended December 31, 2018, 2017 and 2016, respectively, in connection with the incentive plan. As of December 31, 2018, all equity interests subject to the incentive plan have been distributed.

Table of Contents

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 former directors, Howard I. Hoffen and Gregory D. Myers, are managing directors of Metalmark Capital and were directors at the time the Company entered into the 2013 Monarch agreement.

Purchases 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 then owned 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 then owned 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.

Issuance of Class A Shares to JVL

In connection with the August 2016 issuance of Class A common stock pursuant to an underwritten public offering as described in Note 14, "Stockholders' and Mezzanine Equity—Offering of Class A Common Stock," affiliates of JVL Advisors, L.L.C. ("JVL"), who then owned more than 5% of a class of voting securities of the Company, purchased 490,714 shares of Class A common stock, as adjusted for the effects of the 0.087423 per share Special Stock Dividend and the Reverse Stock Split, as defined in Note 14, "Stockholders' and Mezzanine Equity", in the offering, for gross proceeds to the Company of \$25.0 million, before underwriting discounts and commissions of \$1.1 million.

Following its purchase in the offering, JVL owned in excess of 15% of our outstanding voting stock. As a result, the Company entered into a letter agreement with JVL (the "JVL Letter Agreement") in connection with the offering. The JVL Letter Agreement approved, pursuant to Section 203 of the Delaware General Corporation Law ("Section 203"), the purchase of shares of Class A common stock in the offering by JVL. This approval resulted in JVL not being subject to the restrictions on "business combinations" contained in Section 203. In consideration of such approval, JVL agreed that, among other things:

- it will not acquire any material assets of the Company;
- it will not become the owner of more than 19.9% of the Company's outstanding voting stock (other than as a result of actions taken solely by the Company) without the prior approval of the Company's independent directors who are not affiliated with JVL; and

· it will not engage in any “business combination” (as defined in the JVL Letter Agreement).

On May 3, 2017, the Company amended and restated its registration rights agreement dated August 29, 2013 (as amended and restated, the “Restated Registration Rights Agreement”) to add JVL as a party in order to facilitate an orderly distribution of JVL’s shares of Class A common stock in the future, a copy of which was filed on the Company’s Current Report on Form 8-K filed with the Securities and Exchange Commission on May 3, 2017.

Issuance of Series A Preferred Stock

In connection with the August 2016 issuance of Series A preferred stock pursuant to an underwritten public offering as described in Note 14, “Stockholders’ and Mezzanine Equity— Mezzanine Equity,” affiliates of Metalmark, who then owned more than 5% of a class of voting securities of the Company and had two representatives on our Board of Directors, purchased 200,000 shares of Series A preferred stock in the offering, for gross proceeds to the Company of $10.0 million, before underwriting discounts and commissions of $400,000.

Amended and Restated Registration Rights and Stockholders Agreement

On May 2, 2017, we entered into an Amended and Restated Registration Rights and Stockholders Agreement (the "Restated Agreement") with certain entities affiliated with the Jones family (the "Jones Family Entities"), Metalmark and JVL.

The Restated Agreement amends and restates in its entirety that certain Registration Rights and Stockholders Agreement, dated July 29, 2013 (the "Original Agreement"), by and among the Company, Metalmark and the Jones Family Entities, to, among other things, provide JVL with certain rights, in addition to those rights granted to Metalmark and the Jones Family Entities in the Original Agreement, to require the Company to register the sale of any number of JVL's shares of Class A common stock. JVL shall have the right to cause no more than one such required or "demand" registration, which shall be requested by a majority in interest of the JVL holders who hold certain equity securities of the Company or securities convertible or exchangeable into equity securities of the Company. The Company is not obligated to affect any demand registration in which the anticipated aggregate offering price included in such offering is equal to or less than $50,000,000 ($25,000,000 where the registration is on a Form S-3). Furthermore, if, at any time, the Company proposes to register an offering of Class A common stock (subject to certain exceptions) for the Company's own account, then it must give prompt notice to Metalmark, JVL and the Jones Family Entities to allow them to include a specified number of their shares in that registration statement. These registration rights are subject to certain conditions and limitations, including the right of the underwriters to limit the number of shares to be included in a registration and the Company's right to delay or withdraw a registration statement under certain circumstances. The Company will generally be obligated to pay all registration expenses in connection with the registration obligations, regardless of whether a registration statement is filed or becomes effective. The Restated Agreement also includes customary provisions dealing with indemnification, contribution and allocation of expenses.

Purchases of Senior Secured First Lien Notes by Q Investments

On February 14, 2018, Jones Energy Holdings, LLC and Jones Energy Finance Corp. issued $450.0 million 9.25% senior secured first lien notes due 2023 (the "2023 First Lien Notes") in an offering exempt from registration under the Securities Act of 1933, as amended, at an offering price equal to 97.526% of par. One or more affiliates of Q Investments, an affiliate of one of our principal stockholders and an affiliate of the employer of Scott McCarty, one of our directors, purchased an aggregate of $45.0 million of the 2023 First Lien Notes at the issue price.

Letter Agreement with Q Investments

On February 5, 2018, in connection with the appointment of Scott McCarty to the Board, an affiliate of Q Investments delivered an Acknowledgement and Stipulation pursuant to which Q Investments and its affiliates agreed not to (i) effect, seek or propose (whether publicly or otherwise) to effect or participate in any solicitation of proxies or consents to vote any securities of the Company or any of its subsidiaries, including soliciting consents or taking other action with respect to calling of a special meeting of the stockholders of the Company or any of its subsidiaries or engaging in a withhold vote campaign and (ii) otherwise act, alone or in concert with others, to seek representation on the Board or any governing body of a subsidiary of the Company. The obligations set forth remained in effect until May 23, 2018, the day following the Annual Meeting

17. Commitments and Contingencies

Lease obligations

The Company leases approximately 43,000 square feet of office space in Austin, TX under an operating lease arrangement. We also lease approximately 5,000 square feet of office space in Oklahoma City, Oklahoma. Future minimum payments for all noncancellable operating leases extending beyond one year at December 31, 2018 are as follows:

Table of Contents

(in thousands of dollars)	
Years Ending December 31,	
2019	$ 1,231
2020	488
2021	—
2022	—
2023	—
Thereafter	—
	$ 1,719

Rent expense under operating leases was $1.9 million, $1.8 million, and $1.6 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Litigation

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 the Company's 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 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 December 31, 2016, and the charge was recorded as general and administrative expense on the Company's Consolidated Statement of Operations during the second quarter of 2016. In June 2017, the Company presented a revised settlement offer to the plaintiffs and the plaintiff accepted. The settlement was paid in cash during June 2017. Upon settlement, the Company recognized an additional charge of $1.4 million which was recorded as general and administrative expense on the Company's Consolidated Statement of Operations during the second quarter of 2017.

18. Subsequent Events

Contingent Preferred Stock Dividend Declared

On January 16, 2019, the Company's Board declared a contingent quarterly dividend per share equal to 8.0% on an annualized basis based on the liquidation preference of $50.00 per share, or $1.00 per share, on the Series A preferred stock. In order for the Company to pay the dividend in full in shares of Class A common stock in accordance with the terms of the Series A preferred stock, the Dividend Valuation Price would have needed to be at or above the Floor Price. Since the Dividend Valuation Price was below the Floor Price, the Series A preferred stock dividend payable on February 15, 2019 was not paid by the Company, the right to receive those dividends accrued for holders of Series A preferred stock and the Company used its fourth dividend holiday (of five) without penalty. Future Preferred Stock dividend payments will be evaluated on a quarterly basis.

Extended Preferred Stock Conversion Deadline

On November 26, 2018, the Company issued a Fundamental Change notice to holders of the Preferred Stock in conjunction with the delisting of the Company's Class A common stock from the New York Stock Exchange, giving such holders special rights to convert shares of Preferred Stock to Class A Common Stock at a premium to the existing conversion rate until January 14, 2019. On January 8, 2019, the Board approved an extension of the conversion window for holders of the Company's Preferred Stock to February 1, 2019. Then, on January 28, 2019, the Board approved a further extension of the conversion window for holders of the Preferred Stock to February 15, 2019. On February, 8, 2019 the Board again approved a further extension of the conversion window giving such holders special rights to convert shares of Preferred Stock to Class A Common Stock at a premium to the existing conversion rate to March 8, 2019. On February 21, 2019 the Board approved an additional extension of the conversion window giving such holders special rights to convert shares of Preferred Stock to March 31, 2019.

Management Changes

On January 10, 2019, the Board promoted Thomas Hester, 34, an executive officer of the Company and the Company's principal financial officer and principal accounting officer, to the role of Senior Vice President and Chief Financial Officer. Mr. Hester has served in various finance roles for the Company since April 2010, including most recently as the Vice President of Finance. Prior to his time at the Company, Mr. Hester was an Investment Banking Associate in the Energy Group at Jefferies and was an Investment Banking Analyst in the Natural Resources Group at Bear Stearns & Co. Mr. Hester received his Bachelor of Business Administration in Finance and Accounting from Texas Christian University.

Also on January 10, 2019, Jeff Tanner was transitioned from his role as an Executive Vice President and Chief Operating Officer, to the non-executive role of Executive Vice President of Geosciences, effective immediately.

Following Mr. Tanner's transition, the Board promoted Kirk Goehring, 34, the Company's Vice President of Strategy and an executive officer of the Company, to the role of Senior Vice President and Chief Operating Officer, effective immediately. Mr. Goehring has served in various operating, corporate development, and finance roles at the Company since September 2012. Prior to joining the Company, Mr. Goehring was an Associate at Metalmark Capital and an Investment Banking Analyst at Greenhill & Co. and Bear Stearns & Co. Mr. Goehring received his Bachelor of Business Administration from the McCombs School of Business at the University of Texas at Austin.

In connection with Mr. Tanner's transition, Mr. Tanner will receive payment of the remainder of his annual bonus for 2018 under the Company's 2013 Short-Term Incentive Plan, as amended and restated May 4, 2016 (the " STIP "), $112,500, at the time provided for in the STIP, but in no event later than March 15, 2019. In addition, as of March 10, 2019, Mr. Tanner's unvested 2018 cash award of $281,250 pursuant to a cash award agreement (" Cash Award Agreement ") under the Company's 2013 Omnibus Incentive Plan, as amended and restated May 4, 2016 (the " LTIP "), will fully vest and the Company will pay Mr. Tanner the cash amount as provided for in the Cash Award Agreement, but in no event later than April 15, 2019.

Following the changes described above, the Company's executive officers are Carl F. Giesler, Jr., Chief Executive Officer, Thomas Hester, Senior Vice President and Chief Financial Officer, and Kirk Goehring, Senior Vice President and Chief Operating Officer.

Employment Matters

As disclosed on the Company’s Current Report on Form 8-K, filed February 27, 2019 (the “February 8-K”), Jones Energy, LLC entered into (i) Employment Agreements with each of Mr. Hester and Mr. Goehring on February 26, 2019 in their capacity as the Company’s Chief Financial Officer and Chief Operating Officer, respectively and (ii) a Third Amended and Restated Employment Agreement with Mr. Giesler on February 26, 2019 in his capacity as the Company’s Chief Executive Officer. The Company also approved certain retention payments, a Key Employee Incentive Plan and the acceleration of certain payments to be made under the Company’s LTIP and STIP, as described in the February 8-K.

Termination of the Executive Deferral Plan

The Company previously established and maintains the Jones Energy, LLC Executive Deferral Plan (the “ Plan ”). On December 12, 2018, the Compensation Committee of the Board of Directors of the Company (the “ Compensation Committee ”) approved the termination of the Plan as part of its year-end review of the Company’s compensation programs, subject to further approval of definitive documentation. On January 25, 2019, the Compensation Committee approved an amendment to the Plan reflecting the termination (the “ Termination Amendment ”). Pursuant to the terms of the Termination Amendment, effective as of December 12, 2018 (the “ Termination Date ”), the Plan shall be irrevocably terminated, and no further accruals or contributions shall be made under the Plan on or after the Termination Date and all accrued and unpaid benefits of the Participants (as defined in the Plan) as of the Termination Date shall be distributed to the Participants. As of the date of this filing, no current executive officers of the Company were participating, or ever had participated, in the Plan.

Discussions with certain Beneficial Holders of Our Funded Debt

Table of Contents

As previously disclosed, the Company and its advisors have been engaged in discussions with certain beneficial holders of the Company’s unsecured funded debt and other securities (the “Holders”) regarding a potential transaction addressing the Company’s debt and equity (a “Potential Transaction”). To facilitate such discussions, the Company and certain of the Holders entered into a confidentiality agreement (the “Holders NDA”) on December 3, 2018.

Additionally, in connection with a Potential Transaction, the Company has been in discussions with Metalmark Capital (“Metalmark”) regarding the Tax Receivable Agreement by and between JEH LLC, Metalmark and certain of the Company’s current and former owners, dated as of July 29, 2013 (the “Tax Receivable Agreement”). To facilitate such discussions, the Company and Metalmark entered into a confidentiality agreement (the “Metalmark NDA”) on January 14, 2019.

Pursuant to the Holders NDA, the Company agreed to publicly disclose, after a specified period of time if certain conditions were met, that the Company and certain of the Holders were engaged in negotiations related to a Potential Transaction and information regarding such negotiations. Pursuant to the Metalmark NDA, the Company agreed to publicly disclose, after a specified period of time if certain conditions were met, that the Company and Metalmark were engaged in negotiations related to the Tax Receivable Agreement and information regarding such negotiations. To satisfy the Company’s public disclosure obligations under both the Holders NDA and the Metalmark NDA, the information was furnished in a Form 8-K filed on February 1, 2019.

Also included in the Form 8-K filed on February 1, 2019 were the material terms of a Potential Transaction agreed to be disclosed pursuant to the Holders NDA and the Metalmark NDA. The Company has not agreed to consummate a transaction at this time, including the Potential Transaction. No definitive agreement has been reached with the Holders, Metalmark or any other stakeholder. The Company may continue discussions with Metalmark, the Holders, and/or beneficial holders of its first lien secured notes regarding a Potential Transaction.

Potential Delisting from OTCQX

On January 18, 2019, the Company received notice from the OTC Markets Group Inc. that the Company’s market capitalization had stayed below $5,000,000 for more than 30 consecutive days and therefore no longer meets the Standards for Continued Qualification for the OTCQX U.S. tier pursuant to Section 3.2.b.2 of the QTCQX Rules for U.S. Companies. The Company has until July 17, 2019 to regain compliance, during which time the Company must, for 10 consecutive trading days, maintain a minimum bid price of $0.10 per share as of the close of business and a market capitalization of at least $5,000,000, and at least two market makers must publish priced quotations on OTC Link ATS.

If the Company is unable to cure the deficiency by July 17, 2019, the Company plans to apply for trading on the OTCQB market, the second highest tier of the OTC Markets Group.

Departure of Directors

Effective February 20, 2019, Mr. Scott McCarty resigned from the board of directors of Jones Energy, Inc. and all committees thereof. Mr. McCarty was a member of the Nominating and Corporate Governance Committee. The Board accepted Mr. McCarty's resignation on February 21, 2019.

On February 21, 2019, in connection with Mr. McCarty's resignation and pursuant to the bylaws of the Company, the Board voted to decrease the size of the Board from eight to seven members.

Continued efforts to sell non-core asset

On January 15, 2019, the Company closed on the sale of several non-core assets in the Western Anadarko Basin for an agreed upon purchase price of $4.4 million, subject to customary closing adjustments. We continue to seek opportunities to reduce leverage through non-core asset sales. However, we have no assurance that we will be successful in closing any such future divestitures.

19. Subsidiary Guarantors

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

Table of Contents

governing our 2022 Notes and 2023 Notes, as discussed below, and joint and several with all other subsidiary guarantees and the parent guarantees thereunder. Any subsidiaries of JEH other than the subsidiary guarantors and Jones Energy Finance Corp. are immaterial.

The 2023 First Lien Notes are guaranteed on a senior secured 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 Each subsidiary guarantor is 100% owned by JEH, and all guarantees are full and unconditional, subject to customary exceptions pursuant to the indenture governing our 2023 First Lien Notes, as discussed below, and joint and several with all other subsidiary guarantees and the parent guarantee thereunder.

Guarantees of the 2022 Notes, 2023 Notes and 2023 First Lien 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) (in the case of the 2022 Notes and the 2023 Notes) 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.

Table of Contents

Jones Energy, Inc.

Condensed Consolidating Balance Sheet

December 31, 2018

(in thousands of dollars)	JEI (Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets						
Current assets						
Cash and cash equivalents	$ 3,591	$ 35,595	$ 19,278	$ —	$ —	$ 58,464
Accounts receivable, net						
Oil and gas sales	—	—	33,954	—	—	33,954
Joint interest owners	—	—	23,997	—	—	23,997
Other	—	—	614	—	—	614
Commodity derivative assets	—	5,003	—	—	—	5,003
Other current assets	1,877	437	5,785	—	—	8,099
Intercompany receivable	510,075	1,200,295	—	—	(1,710,370)	—
Total current assets	515,543	1,241,330	83,628	—	(1,710,370)	130,131
Oil and gas properties, net, under the successful efforts method	—	—	271,846	—		271,846
Other property, plant and equipment, net	—	—	1,639	—		1,639
Commodity derivative assets	—	1,415	—	—		1,415
Other assets	—	89	326	—		415
Deferred tax assets	129	—	—	—		129
Investment in subsidiaries	(1,219,248)	(7,688)	—	—	1,226,936	—
Total assets	$ (703,576)	$ 1,235,146	$ 357,439	$ —	$ (483,434)	$ 405,575
Liabilities and Stockholders' Equity						
Current liabilities						
Trade accounts payable	$ —	$ 745	$ 31,761	$	$ —	$ 32,506
Oil and gas sales payable	—	—	34,035	—	—	34,035
Accrued liabilities	—	25,567	12,232	—	—	37,799
Commodity derivative liabilities	—	370	—	—	—	370
Other current liabilities	—	1,506	3,421	—	—	4,927
Intercompany payable	—	—	1,707,677	2,693	(1,710,370)	—
Total current liabilities	—	28,188	1,789,126	2,693	(1,710,370)	109,637
Long-term debt	—	982,157	—	—	—	982,157
Deferred revenue	—	4,118	—	—	—	4,118

Asset retirement obligations	—	—	20,432	—	—	20,432
Other liabilities	—	—	495	—	—	495
Total liabilities	—	1,014,463	1,810,053	2,693	(1,710,370)	1,116,839
Mezzanine equity						
Series A preferred stock, $0.001 par value; 1,837,195 shares issued and outstanding at December 31, 2018	93,719	—	—	—	—	93,719
Stockholders'/ members' equity (deficit)						
Members' equity	—	220,683	(1,452,614)	(2,693)	1,234,624	—
Class A common stock, $0.001 par value; 5,025,632 shares issued and 5,024,491 shares outstanding at December 31, 2018	5	—	—	—	—	5
Class B common stock, $0.001 par value; 172,193 shares issued and outstanding at December 31, 2018	—	—	—	—	—	—
Treasury stock, at cost: 1,130 shares at December 31, 2018	(358)	—	—	—	—	(358)
Additional paid-in-capital	638,108	—	—	—	—	638,108
Retained earnings (deficit)	(1,435,050)	—	—	—	—	(1,435,050)
Stockholders' equity (deficit)	(797,295)	220,683	(1,452,614)	(2,693)	1,234,624	(797,295)
Non-controlling interest	—	—	—	—	(7,688)	(7,688)
Total stockholders' equity	(797,295)	220,683	(1,452,614)	(2,693)	1,226,936	(804,983)
Total liabilities and stockholders' equity	$ (703,576)	$ 1,235,146	$ 357,439	$ —	$ (483,434)	$ 405,575

Table of Contents

Jones Energy, Inc.

Condensed Consolidating Balance Sheet

December 31, 2017

(in thousands of dollars)	JEI (Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets						
Current assets						
Cash	$ 5,248	$ 1,180	$ 13,024	$ 20	$ —	$ 19,472
Accounts receivable, net						
Oil and gas sales	—	—	34,492	—	—	34,492
Joint interest owners	—	—	31,651	—	—	31,651
Other	—	—	1,236	—	—	1,236
Commodity derivative assets	—	3,474	—	—	—	3,474
Other current assets	1,866	358	12,152	—	—	14,376
Intercompany receivable	383,849	1,146,647	—	—	(1,530,496)	—
Total current assets	390,963	1,151,659	92,555	20	(1,530,496)	104,701
Oil and gas properties, net, under the successful efforts method	—	—	1,597,040	—	—	1,597,040
Other property, plant and equipment, net	—	—	2,192	527	—	2,719
Commodity derivative assets	—	172	—	—	—	172
Other assets	—	4,427	1,004	—	—	5,431
Investment in subsidiaries	242,617	116,349	—	—	(358,966)	—
Total assets	$ 633,580	$ 1,272,607	$ 1,692,791	$ 547	$ (1,889,462)	$ 1,710,063
Liabilities and Stockholders' Equity						
Current liabilities						
Trade accounts payable	$ 138	$ 247	$ 72,278	$ —	$ —	$ 72,663
Oil and gas sales payable	—	—	31,462	—	—	31,462
Accrued liabilities	62	11,363	10,172	7	—	21,604
Commodity derivative liabilities	—	36,709	—	—	—	36,709
Other current liabilities	1,606	1,723	720	—	—	4,049
Intercompany payable	—	—	1,527,418	3,078	(1,530,496)	—
Total current liabilities	1,806	50,042	1,642,050	3,085	(1,530,496)	166,487
Long-term debt	—	759,316	—	—	—	759,316
Deferred revenue	—	5,457	—	—	—	5,457
Commodity derivative liabilities	—	8,788	—	—	—	8,788
Asset retirement obligations	—	—	19,652	—	—	19,652

Liability under tax receivable agreement	59,596	—	—	—	—	59,596
Other liabilities	—	68	743	—	—	811
Deferred tax liabilities	12,852	1,429	—	—	—	14,281
Total liabilities	74,254	825,100	1,662,445	3,085	(1,530,496)	1,034,388
Mezzanine equity						
Series A preferred stock, $0.001 par value; 1,839,995 shares issued and outstanding at December 31, 2017	89,539	—	—	—	—	89,539
Stockholders'/ members' equity (deficit)						
Members' equity	—	447,507	30,346	(2,538)	(475,315)	—
Class A common stock, $0.001 par value; 4,506,991 shares issued and 4,505,861 shares outstanding at December 31, 2017	5	—	—	—	—	5
Class B common stock, $0.001 par value; 481,391 shares issued and outstanding at December 31, 2017	—	—	—	—	—	—
Treasury stock, at cost: 1,130 shares at December 31, 2017	(358)	—	—	—	—	(358)
Additional paid-in-capital	606,414	—	—	—	—	606,414
Retained earnings (deficit)	(136,274)	—	—	—	—	(136,274)
Stockholders' equity (deficit)	469,787	447,507	30,346	(2,538)	(475,315)	469,787
Non-controlling interest	—	—	—	—	116,349	116,349
Total stockholders' equity	469,787	447,507	30,346	(2,538)	(358,966)	586,136
Total liabilities and stockholders' equity	$ 633,580	$ 1,272,607	$ 1,692,791	$ 547	$ (1,889,462)	$ 1,710,063

Table of Contents

Jones Energy, Inc.

Condensed Consolidating Statement of Operations

Year Ended December 31, 2018

(in thousands of dollars)	JEI (Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Operating revenues						
Oil and gas sales	$ —	$ —	$ 236,873	$ —	$ —	$ 236,873
Other revenues	—	1,555	(2,071)	—	—	(516)
Total operating revenues	—	1,555	234,802	—	—	236,357
Operating costs and expenses						
Lease operating	—	—	44,921	—	—	44,921
Production and ad valorem taxes	—	—	12,087	—	—	12,087
Transportation and processing costs	—	—	3,368	—	—	3,368
Exploration	—	—	8,157	—	—	8,157
Depletion, depreciation and amortization	—	—	173,828	76	—	173,904
Impairment of oil and gas properties	—	—	1,331,785	—	—	1,331,785
Accretion of ARO liability	—	—	1,066	—	—	1,066
General and administrative	—	12,753	18,291	160	—	31,204
Other operating	—	—	250	—	—	250
Total operating expenses	—	12,753	1,593,753	236	—	1,606,742
Operating income (loss)	—	(11,198)	(1,358,951)	(236)	—	(1,370,385)
Other income (expense)						
Interest expense	—	(88,727)	(601)	—	—	(89,328)
Net gain (loss) on commodity derivatives	—	(2,757)	—	—	—	(2,757)
Other income (expense)	53,330	(105)	629	81	—	53,935
Other income (expense), net	53,330	(91,589)	28	81	—	(38,150)
Income (loss) before income tax	53,330	(102,787)	(1,358,923)	(155)	—	(1,408,535)
Equity interest in income (loss)	(1,404,794)	(57,071)	—	—	1,461,865	—
Income tax provision (benefit)	(60,425)	(1,416)	—	—	—	(61,841)
Net income (loss)	(1,291,039)	(158,442)	(1,358,923)	(155)	1,461,865	(1,346,694)
	—	—	—	—	(55,655)	(55,655)

Net income (loss) attributable to non-controlling interests						
Net income (loss) attributable to controlling interests	$ (1,291,039)	$ (158,442)	$ (1,358,923)	$ (155)	$ 1,517,520	$ (1,291,039)
Dividends and accretion on preferred stock	(7,737)	—	—	—	—	(7,737)
Net income (loss) attributable to common shareholders	$ (1,298,776)	$ (158,442)	$ (1,358,923)	$ (155)	$ 1,517,520	$ (1,298,776)

Table of Contents

Jones Energy, Inc.

Condensed Consolidating Statement of Operations

Year Ended December 31, 2017

(in thousands of dollars)	JEI (Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Operating revenues						
Oil and gas sales	$ —	$ —	$ 186,393	$ —	$ —	$ 186,393
Other revenues	—	1,854	326	—	—	2,180
Total operating revenues	—	1,854	186,719	—	—	188,573
Operating costs and expenses						
Lease operating	—	—	36,636	—	—	36,636
Production and ad valorem taxes	—	—	6,874	—	—	6,874
Exploration	—	—	14,145	—	—	14,145
Depletion, depreciation and amortization	—	—	167,133	91	—	167,224
Impairment of oil and gas properties	—	—	149,648	—	—	149,648
Accretion of ARO liability	—	—	960	—	—	960
General and administrative	237	10,146	19,226	283	—	29,892
Total operating expenses	237	10,146	394,622	374	—	405,379
Operating income (loss)	(237)	(8,292)	(207,903)	(374)	—	(216,806)
Other income (expense)						
Interest expense	—	(52,016)	365	—	—	(51,651)
Net gain (loss) on commodity derivatives	—	(17,985)	—	—	—	(17,985)
Other income (expense)	59,492	(93)	(2,447)	—	—	56,952
Other income (expense), net	59,492	(70,094)	(2,082)	—	—	(12,684)
Income (loss) before income tax	59,255	(78,386)	(209,985)	(374)	—	(229,490)
Equity interest in income (loss)	(211,217)	(77,527)	—	—	288,744	—
Income tax provision (benefit)	(50,470)	(197)	—	—	—	(50,667)
Net income (loss)	(101,492)	(155,716)	(209,985)	(374)	288,744	(178,823)
Net income (loss) attributable to non-controlling interests	—	—	—	—	(77,331)	(77,331)
Net income (loss) attributable to controlling interests	$ (101,492)	$ (155,716)	$ (209,985)	$ (374)	$ 366,075	$ (101,492)

Dividends and accretion on preferred stock	(7,924)	—	—	—	—	(7,924)
Net income (loss) attributable to common shareholders	$ (109,416)	$ (155,716)	$ (209,985)	$ (374)	$ 366,075	$ (109,416)

Table of Contents

Jones Energy, Inc.

Condensed Consolidating Statement of Operations

Year Ended December 31, 2016

(in thousands of dollars)	JEI (Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Operating revenues						
Oil and gas sales	$ —	$ —	$ 124,877	$ —	$ —	$ 124,877
Other revenues	—	2,384	586	—	—	2,970
Total operating revenues	—	2,384	125,463	—	—	127,847
Operating costs and expenses						
Lease operating	—	—	32,640	—	—	32,640
Production and ad valorem taxes	—	—	7,768	—	—	7,768
Exploration	—	—	6,673	—	—	6,673
Depletion, depreciation and amortization	—	—	153,843	87	—	153,930
Accretion of ARO liability	—	—	1,263	—	—	1,263
General and administrative	—	12,028	17,244	368	—	29,640
Other operating	—	—	199	—	—	199
Total operating expenses	—	12,028	219,630	455	—	232,113
Operating income (loss)	—	(9,644)	(94,167)	(455)	—	(104,266)
Other income (expense)						
Interest expense	—	(53,080)	(47)	—	—	(53,127)
Gain on debt extinguishment	—	99,530	—	—	—	99,530
Net gain (loss) on commodity derivatives	—	(51,264)	—	—	—	(51,264)
Other income (expense)	784	(321)	73	—	—	536
Other income (expense), net	784	(5,135)	26	—	—	(4,325)
Income (loss) before income tax	784	(14,779)	(94,141)	(455)	—	(108,591)
Equity interest in income (loss)	(66,804)	(42,571)	—	—	109,375	—
Income tax provision (benefit)	(23,468)	(318)	—	—	—	(23,786)
Net income (loss)	(42,552)	(57,032)	(94,141)	(455)	109,375	(84,805)
	—	—	—	—	(42,253)	(42,253)

Net income (loss) attributable to non-controlling interests						
Net income (loss) attributable to controlling interests	$ (42,552)	$ (57,032)	$ (94,141)	$ (455)	$ 151,628	$ (42,552)
Dividends and accretion on preferred stock	(2,669)	—	—	—	—	(2,669)
Net income (loss) attributable to common shareholders	$ (45,221)	$ (57,032)	$ (94,141)	$ (455)	$ 151,628	$ (45,221)

F-53

Table of Contents

Jones Energy, Inc.

Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2018

(in thousands of dollars)	JEI (Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows from operating activities						
Net income (loss)	$ (1,291,039)	$ (158,442)	$ (1,358,923)	$ (155)	$ 1,461,865	$ (1,346,694)
Adjustments to reconcile net income (loss) to net cash provided by operating activities	1,289,627	29,982	1,552,923	135	(1,461,865)	1,410,802
Net cash (used in) / provided by operations	(1,412)	(128,460)	194,000	(20)	—	64,108
Cash flows from investing activities						
Additions to oil and gas properties	—	—	(198,468)	—	—	(198,468)
Proceeds from sales of assets	—	—	11,082	—	—	11,082
Acquisition of other property, plant and equipment	—	—	(360)	—	—	(360)
Current period settlements of matured derivative contracts	—	(53,147)	—	—	—	(53,147)
Net cash (used in) / provided by investing	—	(53,147)	(187,746)	—	—	(240,893)
Cash flows from financing activities						
Proceeds from issuance of long-term debt	—	20,000	—	—	—	20,000
Repayment of long-term debt	—	(231,000)	—	—	—	(231,000)
Proceeds from senior notes	—	438,867	—	—	—	438,867
Payment of debt issuance costs	—	(11,624)	—	—	—	(11,624)
Net payments for share based compensation	—	(466)	—	—	—	(466)
Net cash (used in) / provided by financing	—	215,777	—	—	—	215,777
Net increase (decrease) in cash and cash	(1,412)	34,170	6,254	(20)	—	38,992

equivalents						
Cash and cash equivalents						
Beginning of period	5,248	1,180	13,024	20	—	19,472
End of period	$ 3,836	$ 35,350	$ 19,278	$ —	$ —	$ 58,464

Table of Contents

Jones Energy, Inc.

Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2017

(in thousands of dollars)	JEI (Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows from operating activities						
Net income (loss)	$ (101,492)	$ (155,716)	$ (209,985)	$ (374)	$ 288,744	$ (178,823)
Adjustments to reconcile net income (loss) to net cash provided by operating activities	73,536	52,870	399,795	374	(288,744)	237,831
Net cash (used in) / provided by operations	(27,956)	(102,846)	189,810	—	—	59,008
Cash flows from investing activities						
Additions to oil and gas properties	—	—	(245,364)	—	—	(245,364)
Net adjustments to purchase price of properties acquired	—	—	2,391	—	—	2,391
Proceeds from sales of assets	—	—	61,290	—	—	61,290
Acquisition of other property, plant and equipment	—	—	(586)	—	—	(586)
Current period settlements of matured derivative contracts	—	72,265	—	—	—	72,265
Net cash (used in) / provided by investing	—	72,265	(182,269)	—	—	(110,004)
Cash flows from financing activities						
Proceeds from issuance of long-term debt	—	162,000	—	—	—	162,000
Repayment under long-term debt	—	(129,000)	—	—	—	(129,000)
Payment of debt issuance costs	—	(1,115)	—	—	—	(1,115)
Payment of dividends on preferred stock	(3,368)	—	—	—	—	(3,368)
Net distributions paid to JEH unitholders	1,075	(1,637)	—	—	—	(562)
	—	(462)	—	—	—	(462)

Net payments for share based compensation						
Proceeds from sale of common stock	8,333	—	—	—	—	8,333
Net cash (used in) / provided by financing	6,040	29,786	—	—	—	35,826
Net increase (decrease) in cash	(21,916)	(795)	7,541	—	—	(15,170)
Cash						
Beginning of period	27,164	1,975	5,483	20	—	34,642
End of period	$ 5,248	$ 1,180	$ 13,024	$ 20	$ —	$ 19,472

Table of Contents

Jones Energy, Inc.

Condensed Consolidating Statement of Cash Flows

Year Ended December 31, 2016

(in thousands of dollars)	JEI (Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows from operating activities						
Net income (loss)	$ (42,552)	$ (57,032)	$ (94,141)	$ (455)	$ 109,375	$ (84,805)
Adjustments to reconcile net income (loss) to net cash provided by operating activities	(105,877)	(28,124)	353,426	455	(109,375)	110,505
Net cash (used in) / provided by operations	(148,429)	(85,156)	259,285	—	—	25,700
Cash flows from investing activities						
Additions to oil and gas properties	—	—	(264,462)	—	—	(264,462)
Proceeds from sales of assets	—	—	1,645	—	—	1,645
Acquisition of other property, plant and equipment	—	—	(310)	—	—	(310)
Current period settlements of matured derivative contracts	—	132,265	—	—	—	132,265
Net cash (used in) / provided by investing	—	132,265	(263,127)	—	—	(130,862)
Cash flows from financing activities						
Proceeds from issuance of long-term debt	—	130,000	—	—	—	130,000
Repayment under long-term debt	—	(62,000)	—	—	—	(62,000)
Purchase of senior notes	—	(84,589)	—	—	—	(84,589)
	—	—	—	—	—	—

Payment of debt issuance costs						
Payment of dividends on preferred stock	(1,615)	—	—	—	—	(1,615)
Net distributions paid to JEH unitholders	23,674	(40,993)	—	—	—	(17,319)
Proceeds from sale of common stock	65,446	—	—	—	—	65,446
Proceeds from sale of preferred stock	87,988	—	—	—	—	87,988
Net cash (used in) / provided by financing	175,493	(57,582)	—	—	—	117,911
Net increase (decrease) in cash	27,064	(10,473)	(3,842)	—	—	12,749
Cash						
Beginning of period	100	12,448	9,325	20	—	21,893
End of period	$ 27,164	$ 1,975	$ 5,483	$ 20	$ —	$ 34,642

Table of Contents

Jones Energy, Inc.

Supplemental Information on Oil and Gas Producing Activities (Unaudited)

Geographic Area of Operation

All of our proved reserves are located in the mid continent United States, spanning areas of Oklahoma and Texas. Therefore, the following disclosures are on a total-company basis.

Costs Incurred

Costs incurred for oil and gas property acquisitions, exploration and development for the last three years are as follows:

(in thousands of dollars)	2018	2017	2016
Property acquisitions:			
Unproved	$ 9,680	$ 26,110	$ 137,844
Proved	9,734	6,887	51,388
Exploration	3,966	3,129	412
Development	173,213	215,040	79,617
Total costs incurred (1)	$ 196,593	$ 251,166	$ 269,261

(1) Excludes the impact of asset retirement costs.

Capitalized Costs

Capitalized costs for our oil and gas properties consisted of the following at the end of each of the following years:

(in thousands of dollars)	2018	2017
Unproved properties	$ 96,770	$ 164,087
Proved properties	2,578,644	2,327,629
	2,675,414	2,491,716
Accumulated depletion and impairment	(2,403,568)	(894,676)
Net capitalized costs	$ 271,846	$ 1,597,040

Reserves

Users of this information should be aware that the process of estimating quantities of proved and proved developed oil and gas reserves (including natural gas liquids) is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir also may change substantially over time as a result of numerous factors, including additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates may occur from time to time.

The following tables set forth the Company's total proved reserves and the changes in the Company's total proved reserves. These reserve estimates are based in part on reports prepared by Cawley, Gillespie & Associates, Inc. ("Cawley Gillespie"), independent petroleum engineers, utilizing data compiled by us. In preparing its reports, Cawley

Gillespie evaluated properties representing all of the Company’s proved reserves at December 31, 2018, 2017, and 2016. The Company’s proved reserves are located onshore in the United States. There are many uncertainties inherent in estimating proved reserve quantities, and projecting future production rates and the timing of future development expenditures. In addition, reserve estimates of new discoveries are more imprecise than those of properties with production history. Accordingly, these estimates are subject to change as additional information becomes available. Proved reserves are the estimated quantities of natural gas, natural gas liquids and oil that geoscience and engineering data demonstrate with reasonable certainty to be economically producible in future years from known oil and natural gas reservoirs under existing economic conditions, operating methods and government regulations at the end of the respective years. Proved

Table of Contents

developed reserves are those reserves expected to be recovered through existing wells with existing equipment and operating methods.

The following table summarizes changes in estimated proved reserves from December 31, 2015 to December 31, 2018 by commodity type:

	Crude Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBoe)(1)
Estimated Proved Reserves				
December 31, 2015	25,408	32,649	261,596	101,657
Extensions and discoveries	774	750	4,767	2,319
Production	(1,690)	(2,210)	(18,878)	(7,046)
Purchases of minerals in place	2,326	3,829	42,713	13,275
Sales of minerals in place	(37)	—	(1)	(37)
Revisions of previous estimates	(3,187)	(593)	(7,057)	(4,959)
December 31, 2016	23,594	34,425	283,140	105,209
Extensions and discoveries	9,493	8,752	62,514	28,663
Production	(1,964)	(2,418)	(20,425)	(7,786)
Purchases of minerals in place	—	—	—	—
Sales of minerals in place	(114)	(4,442)	(54,670)	(13,668)
Revisions of previous estimates	(1,995)	(3,044)	(15,411)	(7,606)
December 31, 2017	29,014	33,273	255,148	104,812
Extensions and discoveries	2,116	2,344	23,485	8,374
Production	(2,241)	(2,500)	(21,384)	(8,305)
Purchases of minerals in place	—	—	—	—
Sales of minerals in place	—	—	—	—
Revisions of previous estimates	(13,134)	(11,533)	(73,365)	(36,895)
December 31, 2018	15,755	21,584	183,884	67,986

(1) Barrels of oil equivalent determined using the ratio of six Mcf of natural gas to one Bbl of crude oil or natural gas liquids.

For the year ended December 31, 2018, the Company added 8,374 MBoe through extensions, which represent the conversion of unproved reserves to proved reserves as a result of our drilling activity during the year, primarily in the Merge area. There were no discoveries of proved reserves. The Company's estimated proved reserves were reduced by current year production of 8,305 MBoe. No sales or purchases of minerals in place occurred during the year ended December 31, 2018.

For the year ended December 31, 2018, the Company had net negative revisions of 36,895 MBoe. The decrease was due to revisions of previous estimates, including negative revisions of 23,600 MBoe of proved undeveloped reserves due to the Company's limited capital resources available to fund our drilling program, negative revisions of 10,700 MBoe of proved undeveloped reserves rescheduled outside of five years from their initial booking due to reduced drilling, and net negative revisions of 4,800 MBoe due to lease expirations.

For the year ended December 31, 2017, the Company added 28,663 MBoe through extensions, which represent the conversion of unproved reserves to proved reserves as a result of our drilling activity during the year, primarily in the Merge area. There were no discoveries of proved reserves. The Company's estimated proved reserves were reduced by current year production of 7,786 MBoe. The Company had sales of minerals in place of 13,668 MBoe during the year ended December 31, 2017, primarily as a result of the Arkoma Divestiture. No purchases of minerals in place occurred during the year ended December 31, 2017.

For the year ended December 31, 2017, the Company had net negative revisions of 7,606 MBoe, of which 10,730 MBoe was related to Western Anadarko proved undeveloped reserves no longer expected to be developed within five years of first booking or before the lease expired. This was offset by net positive revisions related to commodity pricing of 3,612 Mboe. The remaining net negative revisions of 488 MBoe were primarily related to negative Western Anadarko well performance.

For the year ended December 31, 2016, the Company added 2,319 MBoe through extensions, which represent the conversion of unproved reserves to proved reserves as a result of our drilling activity during the year. There were no discoveries of proved reserves. The Company's estimated proved reserves were reduced by current year production of 7,046 MBoe. The Company added 13,275 MBoe through the purchases of minerals in place. Purchases were primarily related to leasing and the asset purchases in the Western Anadarko Basin. The Company also had sales of minerals in place of 37 MBoe during the year ended December 31, 2016.

For the year ended December 31, 2016, the Company had net negative revisions of 4,959 MBoe, of which 1,685 MBoe was related to commodity pricing and 4,155 MBoe was related to proved undeveloped reserves revisions. The remaining net positive revisions of 881 MBoe were primarily related to changes in working interest, cost reductions, and production performance enhancements.

The following table summarizes estimated proved developed and undeveloped reserves by commodity type as of December 31, 2018, 2017 and 2016:

	Crude Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBoe)(1)
Estimated Proved Reserves				
December 31, 2016				
Proved developed	11,471	20,941	180,293	62,461
Proved undeveloped	12,123	13,484	102,847	42,748
Total proved reserves	23,594	34,425	283,140	105,209
December 31, 2017				
Proved developed	15,416	20,181	159,459	62,173
Proved undeveloped	13,598	13,092	95,690	42,639
Total proved reserves	29,014	33,273	255,148	104,812
December 31, 2018				
Proved developed	13,754	19,699	165,212	60,988
Proved undeveloped	2,001	1,885	18,672	6,998
Total proved reserves	15,755	21,584	183,884	67,986

(1) Barrels of oil equivalent determined using the ratio of six Mcf of natural gas to one Bbl of crude oil or natural gas liquids.

Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves

The following information was developed utilizing procedures prescribed by FASB Accounting Standards Codification Topic 932, Extractive Industries—Oil and Gas (Topic 932). The "standardized measure of discounted future net cash flows" should not be viewed as representative of the current value of our proved oil and gas reserves. It and the other information contained in the following tables may be useful for certain comparative purposes, but should not be solely relied upon in evaluating the Company or its performance.

In reviewing the information that follows, the following factors should be taken into account:

- future costs and sales prices will probably differ from those required to be used in these calculations;
- actual production rates for future periods may vary significantly from the rates assumed in the calculations;
- future tax rates, deductions and credits are calculated under current laws, which may change in future years;
- a 10% discount rate may not be reasonable relative to risk inherent in realizing future net oil and natural gas revenues.

Under the standardized measure, future cash inflows were estimated by using the average of the historical unweighted first day of the month prices of oil and natural gas for the prior twelve month periods ended December 31, 2018, 2017, and 2016. Future cash inflows do not reflect the impact of open hedge positions. Future cash inflows were reduced by

Table of Contents

estimated future development and production costs based on year end costs in order to arrive at net cash flows. Use of a 10% discount rate, first day of the month prices and year end costs are required by ASC 932.

In general, management does not rely on the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves and varying price and cost assumptions considered more representative of a range of possible outcomes.

The standardized measure of discounted future net cash flows from the Company's estimated proved oil and natural gas reserves follows:

(in thousands of dollars)	2018	2017	2016
Future cash inflows	$ 1,825,878	$ 2,551,709	$ 2,158,067
Less related future:			
Production costs	(674,401)	(791,302)	(798,161)
Development costs	(101,087)	(460,496)	(451,790)
Income tax expenses (1)	(58,377)	(142,196)	(46,139)
Future net cash flows	992,013	1,157,715	861,977
10% annual discount for estimated timing of cash flows	(445,327)	(592,194)	(478,498)
Standardized measure of discounted future net cash flows	$ 546,686	$ 565,521	$ 383,479

(1) The decrease in 2018 future income tax expense is due to the decrease in future taxable income. The increase in 2017 future income tax expense is due to the increase in future taxable income allocated to the Company and the limits applicable to the utilization of net operating losses, offset by the decrease in applicable tax rate from 35% to 21% due to the changes in the US Tax Law effective January 1, 2018.

A summary of the changes in the standardized measure of discounted future net cash flows applicable to proved natural gas and crude oil reserves follows:

(in thousands of dollars)	2018	2017	2016
Balance, beginning of period	$ 565,521	$ 383,479	$ 464,780
Net change in sales and transfer prices, net of production expenses	210,516	127,748	(90,932)
Changes in estimated future development costs	868	(11,838)	32,678
Sales and transfers of oil and gas produced during the period	(190,381)	(145,801)	(94,262)
Net change due to extensions and discoveries	101,657	110,752	24
Net change due to purchases of minerals in place	—	—	18,473
Net change due to sales of minerals in place	—	(51,573)	(1,202)
Net change due to revisions in quantity estimates	(239,553)	(5,526)	(51,237)
Previously estimated development costs incurred during the period	5,783	197,444	73,735
Net change in income taxes	38,260	(43,193)	(12,824)
Accretion of discount	50,897	27,943	37,475
Other	3,118	(23,914)	6,771
Balance, end of period	$ 546,686	$ 565,521	$ 383,479

Table of Contents

Supplemental Quarterly Financial Information (Unaudited)

Following is a summary of the Company's results of operations by quarter for the years ended December 31, 2018 and 2017.

(in thousands except per share data)	2018 First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
Revenues	$ 57,489	$ 65,255	$ 59,726	$ 53,887	$ 236,357
Operating income (loss)	(8,758)	(4,923)	(6,277)	(1,350,427)	(1,370,385)
Net income (loss)	(28,920)	(46,931)	(35,355)	(1,235,488)	(1,346,694)
Net income (loss) attributable to non-controlling interests	(3,559)	(5,416)	(2,264)	(44,416)	(55,655)
Net income (loss) attributable to controlling interests	(25,361)	(41,515)	(33,091)	(1,191,072)	(1,291,039)
Basic earnings per share	$ (6.00)	$ (9.31)	$ (7.16)	$ (239.73)	$ (271.94)
Diluted earnings per share	$ (6.00)	$ (9.31)	$ (7.16)	$ (239.73)	$ (271.94)

(in thousands except per share data)	2017 First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
Revenues	$ 41,233	$ 48,626	$ 44,202	$ 54,512	$ 188,573
Operating income	(13,507)	(172,565)	(24,407)	(6,327)	(216,806)
Net income (loss)	(3,515)	(133,978)	(82,963)	41,633	(178,823)
Net income (loss) attributable to non-controlling interests	(2,128)	(51,762)	(18,157)	(5,284)	(77,331)
Net income (loss) attributable to controlling interests	(1,387)	(82,216)	(64,806)	46,917	(101,492)
Basic earnings per share	$ (1.10)	$ (25.63)	$ (18.27)	$ 10.17	$ (30.22)
Diluted earnings per share	$ (1.10)	$ (25.63)	$ (18.27)	$ 10.17	$ (30.22)