JONES
ENERGY

2015 Annual Report and Proxy Statement

About Jones Energy

Jones Energy, Inc. (NYSE: JONE) is an Austin, Texas-based independent oil and gas company engaged in the development, production, and acquisition of oil and natural gas properties in the Anadarko and Arkoma Basins of Texas and Oklahoma.

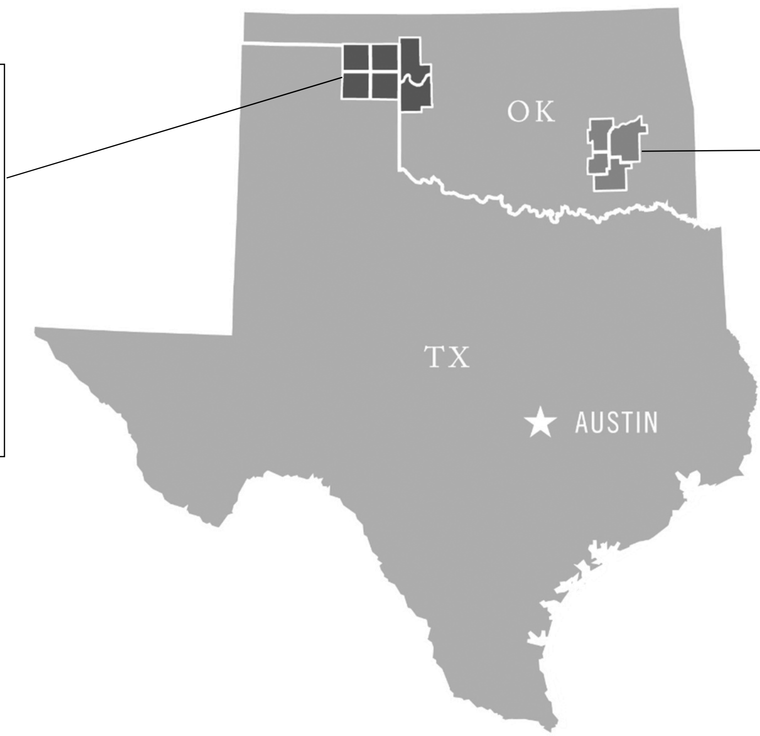
Operations Overview

Anadarko Basin

Key Formation
Cleveland

Drilling Locations
711

2015 Daily Production
18.4 MBoe/d



Arkoma Basin

Key Formation
Woodford

Drilling Locations
277

2015 Daily Production
3.6 MBoe/d

Key Statistics

Total Proved Reserves	Daily Production	Gross Acreage	Gross Drilling Locations
101.7 MMBoe	25,134 Boe/d	228,224	2,103

Dear Fellow Shareholders,

There is a saying that history doesn't repeat itself, but it often rhymes.

I started my first job in 1984 as a geologist for a large integrated oil company. Times were good. Business was booming. We were optimistic about the future.

Fast forward two short years later. Oil and gas prices were cut in half. The industry was distressed.

Early in my career, I learned that the only predictable thing about this industry is its unpredictability. I also recognized that no one knows what the future holds, but those who are prepared for the future are the ones that succeed.

In 1988, when I founded the company, Jones Energy was a long way from becoming the public company we are today. But the values we learned from drilling our very first well still hold true today. In fact, the first well Jones Energy ever drilled was a dry hole.

There are always obstacles in life - some you cause and some that are out of your control - but how you react to those obstacles is what seals your fate.

Although 2015 was a tough year for the oil and gas industry, as a company, we delivered on the promises we made and achieved the four key directives we laid out for the year:

1. We stuck to our bread and butter.
   - Demonstrated that the Cleveland is a world class resource play
   - Delivered solid performance driven by Cleveland activity
2. We maintained operating flexibility.
   - Transitioned seamlessly between adding and dropping rigs throughout the year
   - Achieved continuous improvements in drill times
3. We maximized returns through cost management.
   - Achieved a 40% reduction in Cleveland well costs
   - Maintained relentless cost focus
4. We prepared for market opportunities.
   - Substantial hedge book bolsters cash flow
   - Managed balance sheet in a conservative manner
   - Leased over 10,000 net acres in the Cleveland for approximately $3 million

In conclusion, we understand that the past is just that, the past. It cannot foretell the future. But we have over 30 years of experience in the oil and gas industry. We have been here before; we have the playbook. We also know from experience that difficult times create great opportunity, and we will do everything in our power to translate that opportunity into shareholder value.

Thank you for your continued support and belief in Jones Energy. I am confident in our company's future and motivated by the opportunities that lie ahead.

Yours truly,

Jonny Jones
Founder, Chairman, & CEO
Jones Energy

JONES ENERGY, INC.

807 Las Cimas Parkway, Suite 350
Austin, Texas 78746

NOTICE OF ANNUAL MEETING OF STOCKHOLDERS
To Be Held on May 4, 2016

To the Stockholders of Jones Energy, Inc.:

You are cordially invited to attend the 2016 annual meeting of stockholders of Jones Energy, Inc. This is your notice for the meeting.

TIME AND DATE:	9:30 a.m. Central Time on May 4, 2016
PLACE:	Jones Energy, Inc., 807 Las Cimas Parkway, Suite 350, Austin, Texas 78746
ITEMS OF BUSINESS:	• To elect two directors to serve as the Class III directors, each for a three-year term; • To ratify PricewaterhouseCoopers LLP as independent registered public accounting firm of Jones Energy, Inc. for the fiscal year ending December 31, 2016; • To approve the Amended and Restated Jones Energy, Inc. 2013 Omnibus Incentive Plan; • To approve the Amended and Restated Jones Energy, Inc. 2013 Short-Term Incentive Plan; and • To transact such other business as may properly come before the annual meeting and any reconvened meeting following any adjournments or postponements of the meeting.
RECORD DATE:	The record date for the annual meeting is March 9, 2016. Only stockholders of record at the close of business on that date may vote at the annual meeting or any adjournment or postponement of the meeting.
PROXY VOTING:	**YOUR VOTE IS IMPORTANT.** Whether or not you expect to attend the annual meeting in person, please submit your proxy or voting instructions over the telephone, the internet or by mail as soon as possible to ensure that your shares are represented at the annual meeting and your vote is properly recorded. Even if you vote by one of these methods, you may still vote in person if you attend the annual meeting. For specific voting information, please see Questions and Answers About the Annual Meeting beginning on page 1 of the Proxy Statement that follows. **Even if you plan to attend the meeting, please sign, date and return the enclosed proxy card or submit your proxy using the internet or telephone procedures described on the proxy card.**

By Order of the Board of Directors,

Jonny Jones
Founder, Chairman and Chief Executive Officer

Austin, Texas
April 1, 2016

IMPORTANT NOTICE REGARDING THE AVAILABILITY OF PROXY MATERIALS FOR THE SHAREHOLDER MEETING TO BE HELD MAY 4, 2016
The proxy statement and annual report to stockholders are available at:
http://www.viewproxy.com/jonesenergy/2016

TABLE OF CONTENTS

QUESTIONS AND ANSWERS ABOUT THE ANNUAL MEETING	1
PROPOSAL ONE: ELECTION OF CLASS III DIRECTORS	10
BOARD OF DIRECTORS AND CORPORATE GOVERNANCE	10
Board Structure	10
Information about the Directors and Nominees	11
Business Experience and Qualifications of Directors	11
Meetings of the Board	13
Corporate Governance	13
Director Independence	14
Board Committees	14
Compensation Committee Interlocks and Insider Participation	16
Code of Business Conduct and Ethics	16
Director Nominations	17
Contacting the Board, the Chairman and Other Independent Directors	17
Board Leadership and Role in Risk Oversight	17
EXECUTIVE OFFICERS	18
EXECUTIVE COMPENSATION	19
Compensation of Named Executive Officers	19
Jones Energy, Inc. 2013 Omnibus Incentive Plan	21
Jones Energy, Inc. 2013 Short-Term Incentive Plan	21
Monarch Equity Plan	22
Deferred Compensation Plan	22
Potential Payments Upon Termination or Change in Control	23
DIRECTOR COMPENSATION	23
AUDIT COMMITTEE REPORT	24
CERTAIN RELATIONSHIPS AND RELATED PERSON TRANSACTIONS	25
IPO Related Agreements	25
Transactions with Our Executive Officers, Directors and 5% Stockholders	27
Procedures for Approval of Related Party Transactions	28
PRINCIPAL STOCKHOLDERS	29
SECTION 16(A) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE	33
PROPOSAL TWO: RATIFICATION OF INDEPENDENT PUBLIC ACCOUNTING FIRM	33
PRICEWATERHOUSECOOPERS LLP FEES FOR FISCAL YEARS 2015 AND 2014	34
PROPOSAL THREE—APPROVAL OF THE AMENDED AND RESTATED JONES ENERGY, INC. 2013 OMNIBUS INCENTIVE PLAN	35
Background and Purpose	35
Administration	37
Participation and Eligibility	38
Number of Authorized Shares	38
Limits on Awards	38
Summary of Awards under the LTIP	39
U.S. Income Tax Considerations	42
New Plan Benefits	44
Equity Compensation Plan Information	45
Consequences of Failing to Approve the Proposal	45
Vote Required	45
PROPOSAL FOUR—APPROVAL OF THE JONES ENERGY, INC. 2013 SHORT-TERM INCENTIVE PLAN	45
Plan Administration and Eligibility	46
Awards	46
Performance Goals	46
Claw back	47

Amendment and Termination of Plan . . . 47
New STIP Benefits . . . 47
Consequences of Failing to Approve the Proposal . . . 47
Vote Required . . . 47
STOCKHOLDER PROPOSALS AND DIRECTOR NOMINATIONS . . . 48
Proposals for 2017 Annual Meeting . . . 48
Nominations for 2017 Annual Meeting . . . 48
SOLICITATION AND MAILING OF PROXIES . . . 49
STOCKHOLDER LIST . . . 49
HOUSEHOLDING . . . 49
WHERE YOU CAN FIND MORE INFORMATION ABOUT US . . . 50
OTHER MATTERS FOR 2017 ANNUAL MEETING . . . 50

JONES ENERGY, INC.

807 Las Cimas Parkway, Suite 350
Austin, Texas 78746

PROXY STATEMENT

2016 Annual Meeting of Stockholders

To Be Held on May 4, 2016

The accompanying proxy, mailed together with this proxy statement, is being furnished to you in connection with the solicitation of proxies by and on behalf of the Board of Directors of Jones Energy, Inc. (the "Board") for use at our 2016 Annual Meeting of Stockholders (the "Annual Meeting") or at any reconvened meeting after any adjournments or postponements thereof. This proxy statement and accompanying proxy were first mailed to our stockholders on or about April 1, 2016. Unless the context requires otherwise, the terms "Jones Energy," "the Company," "our," "we," "us" and similar terms refer to Jones Energy, Inc., together with its consolidated subsidiaries.

The Annual Meeting will be held on May 4, 2016, at 9:30 a.m. Central Time, at the Jones Energy, Inc. offices, located at 807 Las Cimas Parkway, Suite 350, Austin, Texas 78746. You can obtain directions to the Annual Meeting by calling our Investor Relations line at **512.493.4834**. Only holders of record of shares at the close of business on March 9, 2016 (the "Record Date") were entitled to notice of, and are entitled to vote at, the Annual Meeting and any reconvened meeting following any adjournments or postponements thereof, unless such adjournment or postponement is for more than 30 days, in which event we will set a new record date.

You can vote your shares at the meeting or by telephone, over the Internet or by completing, signing, dating and returning your proxy in the enclosed envelope.

QUESTIONS AND ANSWERS ABOUT THE ANNUAL MEETING

Questions	Answers
Q: What is the purpose of the Annual Meeting?	A: To vote on the following proposals: • To elect two directors to serve as the Class III directors, each for a three-year term; • To ratify PricewaterhouseCoopers LLP as independent registered public accounting firm of Jones Energy, Inc. for the fiscal year ending December 31, 2016; • To approve the Amended and Restated Jones Energy, Inc. 2013 Omnibus Incentive Plan; • To approve the Amended and Restated Jones Energy, Inc. 2013 Short-Term Incentive Plan; and • To transact such other business as may properly come before the annual meeting and any reconvened meeting following any adjournments or postponements of the meeting.
Q: How does the Board recommend I vote on these proposals?	A: The Board recommends a vote: • **FOR** the election of Alan D. Bell and Gregory D. Myers as Class III directors;

Questions	Answers
	• **FOR** the ratification of the appointment of PricewaterhouseCoopers LLP as our independent registered public accounting firm for the fiscal year ending December 31, 2016; • **FOR** the Amended and Restated Jones Energy, Inc. 2013 Omnibus Incentive Plan; and • **FOR** the Amended and Restated Jones Energy, Inc. 2013 Short-Term Incentive Plan.
Q: Why did I receive a full set of proxy materials?	A: Pursuant to rules promulgated by the Securities and Exchange Commission ("SEC"), we have elected to provide access to our proxy materials both by sending you this full set of proxy materials, including a proxy card, and by notifying you of the availability of the proxy material on the Internet. Our Board has made these proxy materials available to you on the Internet on or about April 1, 2016, at: *http://www.viewproxy.com/jonesenergy/2016*
Q: Who is making this solicitation?	A: This proxy for the Annual Meeting is being solicited on behalf of the Board of Jones Energy, Inc.
Q: Who is entitled to vote at the meeting?	A: *Stockholders Entitled to Vote*: Stockholders who our records show owned shares of our Common Stock (as defined below) as of the close of business on the Record Date may vote at the Annual Meeting. On the Record Date, we had 30,550,907 shares of Class A common stock (the "Class A Shares") outstanding and 31,273,130 shares of Class B common stock (the "Class B Shares," and together with the Class A Shares, the "Common Stock") outstanding. All of the outstanding Class B Shares are owned by affiliates of Metalmark Capital Partners ("Metalmark"), Wells Fargo Central Pacific Holdings, Inc. ("Wells Fargo") and entities directly or indirectly owned or controlled by Jonny Jones, our Chairman of the Board and Chief Executive Officer, and/or his immediate family (the "Jones Family Entities," and collectively with Metalmark and Wells Fargo, the "Pre-IPO Owners"). *Registered Stockholders*: If your shares are registered directly in your name with Jones Energy's transfer agent, you are considered the holder of record with respect to those shares. As the holder of record, you have the right to grant your voting proxy directly to the individuals listed on the proxy card or to vote in person at the Annual Meeting.

Questions	Answers
	Street Name Stockholders: If your shares are held in a stock brokerage account or by a bank or other nominee, you are considered the beneficial owner of shares held in street name and your broker or nominee is considered the holder of record with respect to those shares. As the beneficial owner, you have the right to direct your broker or nominee how to vote your shares. Beneficial owners are also invited to attend the Annual Meeting. However, since you are not the holder of record, you may not vote your shares in person at the Annual Meeting unless you follow your broker's procedures for obtaining a legal proxy. Street name stockholders wishing to attend the Annual Meeting in person should also bring proof of ownership, such as a brokerage statement, showing their ownership of stock as of the Record Date.
Q: How can I vote my shares?	A: *Registered Stockholders*: Registered stockholders may vote in person at the Annual Meeting or by one of the following methods: • *By mail*. Complete and sign your enclosed proxy card and mail it in the enclosed postage prepaid envelope to Vote Processing, c/o Alliance Advisors LLC, PO Box 2400, Pittsburgh, PA 15230-9763. Alliance Advisors must receive the proxy card not later than May 3, 2016, the day before the annual meeting, for your mailed proxy to be valid and your vote to count. Your shares will be voted according to your instructions. If you return your proxy card but do not specify how you want your shares voted on any particular matter, they will be voted in accordance with the recommendations of our board of directors; • *By telephone*. Call 1-888-693-8683, toll free from the United States, Canada and Puerto Rico, and follow the recorded instructions. You must specify how you want your shares voted and confirm your vote at the end of the call or your telephone vote cannot be completed. Your shares will be voted according to your instructions. You must submit your telephonic proxy before 11:59 p.m., Eastern Daylight Time, on May 3, 2016, the day before the annual meeting, for your telephonic proxy to be valid and your vote to count;

- *By internet*. Access the secure website registration page through the internet at *www.cesvote.com*. Use the vote control number printed on your enclosed proxy card to access your account and vote your shares. You must specify how you want your shares voted or your Internet vote cannot be completed and you will receive an error message. Your shares will be voted according to your instructions. You must submit your Internet proxy before 11:59 p.m., Eastern Daylight Time, on May 3, 2016, the day before the annual meeting, for your proxy to be validly submitted over the Internet and your vote to count.

Please note that the internet and voting facilities for registered stockholders will close at 11:59 p.m. Eastern Daylight Time on May 3, 2016.

Street Name Stockholders: If you hold your shares through a broker, bank or other nominee, you should receive instructions on how to vote your shares from your broker, bank or other nominee. Please follow their instructions carefully. Also, if you wish to vote in person at the Annual Meeting, you must request a legal proxy from the bank, broker or other nominee that holds your shares and present that proxy and proof of identification at the Annual Meeting. Street name stockholders may generally vote by one of the following methods:

- *By mail*. You will receive instructions from your bank, brokerage firm, or other nominee explaining how you can vote your shares by mail. You should follow those instructions;
- *By methods listed on Voting Instruction Card*. Please refer to your voting instruction card or other information provided by your bank, broker, nominee or other holder of record to determine whether you may vote by telephone or electronically on the Internet, and follow the instructions on the voting instruction card or other information provided by the holder of record
- *In person with a proxy from the record holder*. A street name stockholder who wishes to vote at the Annual Meeting will need to obtain a legal proxy from his or her bank, brokerage firm or other nominee. Please consult the voting instruction card provided to you by your bank, broker or other nominee to determine how to obtain a legal proxy in order to vote in person at the Annual Meeting.

Q: Can I attend the meeting in person?

A: Yes. You are invited to attend the Annual Meeting if you are a registered stockholder or a street name stockholder as of the Record Date. In order to enter the Annual Meeting, you must present a form of photo identification acceptable to us, such as a valid driver's license or passport. Please note that since a street name stockholder is not the holder of record, you may not vote your shares in person at the Annual Meeting unless you follow your broker's procedures for obtaining a legal proxy.

Q: If I submit a proxy, how will it be voted?

A: When proxies are properly dated, executed and returned, the shares represented by such proxies will be voted at the Annual Meeting in accordance with the instructions of the stockholder. If no specific instructions are given, however, the shares will be voted in accordance with the recommendations of our Board as described above. If any matters not described in the Proxy Statement are properly presented at the Annual Meeting, the proxy holders will use their own judgment to determine how to vote your shares. If the Annual Meeting is adjourned, the proxy holders can vote your shares on the new meeting date as well, unless you have revoked your proxy instructions, as described below under "Can I change my vote?"

Q: Can I change my vote?

A: Yes. You may change your vote at any time prior to the vote at the Annual Meeting. To revoke your proxy instructions and change your vote if you are a holder of record, you must (i) attend the Annual Meeting and vote your shares in person, (ii) advise our Corporate Secretary at our principal executive offices (807 Las Cimas Parkway, Suite 350, Austin, Texas 78746) in writing before the proxy holders vote your shares, (iii) deliver later dated and signed proxy instructions (which must be received prior to the Annual Meeting) or (iv) vote again on a later date on the internet or by telephone (only your latest Internet or telephone proxy submitted prior to the Annual Meeting will be counted).

Q: What happens if I decide to attend the Annual Meeting, but I have already voted or submitted a proxy covering my shares?

A: You may attend the meeting and vote in person even if you have already voted or submitted a proxy. Please be aware that attendance at the Annual Meeting will not, by itself, revoke a proxy. If a bank, broker or other nominee is the record holder of your shares and you wish to attend the Annual Meeting and vote in person, you must obtain a legal proxy from the holder of record of the shares giving you the right to vote the shares.

Questions	Answers
Q: What quorum is required for the Annual Meeting?	A: The presence, in person or by proxy, of the holders as of the Record Date of a majority of the voting power of the issued and outstanding Common Stock entitled to vote at the meeting is required for the Annual Meeting to proceed. Withheld votes, abstentions and broker non-votes (which result when a broker holding shares for a beneficial owner has not received timely voting instructions on certain matters from such beneficial owner and when the broker does not otherwise have discretionary power to vote on a particular matter) will count as present for purposes of establishing a quorum on the proposals.
Q: How are votes counted?	A: The Class A Shares and Class B Shares are voting together as a single class on all matters described in this Proxy Statement for which your proxy is being solicited. Each share of Common Stock entitles its holder to one vote per share on all matters. There is no cumulative voting.
Q: How many votes are needed to approve each proposal?	A: *Election of Class III Directors*: Each Class III director is elected by a plurality of the voting power of the Class A Shares and the Class B Shares, voting together as a single class, present and in person or represented by a proxy and entitled to vote on the election of directors. Abstentions and broker non-votes will have no effect on the outcome of the vote. *Ratification of Independent Registered Public Accounting Firm*: The ratification of the appointment of PricewaterhouseCoopers LLP as the Company's independent registered public accounting firm requires the affirmative vote of the majority of shares cast on the matter. Abstentions shall not be considered as votes cast. *Approval of Amended and Restated Jones Energy, Inc. 2013 Omnibus Incentive Plan:* The amended and restated Jones Energy, Inc. 2013 Omnibus Incentive Plan, which includes an increase of the number of authorized shares, requires the affirmative vote of the majority of shares cast on the matter. Abstentions and broker non-votes will have no effect on the outcome of the vote. *Approval of Amended and Restated Jones Energy, Inc. 2013 Short-Term Incentive Plan:* The Amended and Restated Jones Energy, Inc. 2013 Short-Term Incentive Plan requires the affirmative vote of the majority of shares cast on the matter. Abstentions and broker non-votes will have no effect on the outcome of the vote.

Questions	Answers
Q: What are broker non-votes?	A: Broker non-votes are shares held by brokers that do not have discretionary authority to vote on the matter and have not received voting instructions from their clients. If your broker holds your shares in its name and you do not instruct your broker how to vote, your broker will nevertheless have discretion to vote your shares on our sole "routine" matter—the ratification of the appointment of the Company's independent registered public accounting firm. Your broker will not have discretion to vote on the election of directors, the Amended and Rrestated Jones Energy, Inc. 2013 Omnibus Incentive Plan or the Amended and Restated Jones Energy, Inc. 2013 Short-Term Incentive Plan. Broker non-votes do not count for voting purposes, but are considered "present" at the meeting for purposes of determining whether a quorum exists.
Q: Who will tabulate the votes?	A: Jones Energy has designated a representative of Alliance Advisors, LLC as the Inspector of Election who will tabulate the votes.
Q: Who pays for the proxy solicitation process?	A: Jones Energy will pay the cost of preparing, assembling, printing, mailing and distributing these proxy materials and soliciting votes. We may, on request, reimburse brokerage firms and other nominees for their expenses in forwarding proxy materials to beneficial owners. In addition to soliciting proxies by mail, we expect that our directors, officers and employees may solicit proxies in person or by telephone or facsimile. None of these individuals will receive any additional or special compensation for doing this, although we will reimburse these individuals for their reasonable out-of-pocket expenses.
Q: May I propose actions for consideration at next year's annual meeting of stockholders or nominate individuals to serve as directors?	A: Yes. You may present proposals for action at a future meeting or submit nominations for election of directors only if you comply with the requirements of the proxy rules established by the SEC and our amended and restated bylaws ("Bylaws"), as applicable. In order for a stockholder proposal to be included in our proxy statement and form of proxy relating to the meeting for our 2017 Annual Meeting of Stockholders under rules set forth in the Securities Exchange Act of 1934, as amended (the "Exchange Act"), the proposal must be received by us no later than January 4, 2017.

If a stockholder intends to submit a proposal that is not intended to be included in our proxy statement, or a nomination for director for our 2017 Annual Meeting of Stockholders, the stockholder must give us notice in accordance with the requirements set forth in our Bylaws no later than February 3, 2017 and no earlier than January 4, 2017. If the date of the 2017 Annual Meeting is more than 30 days before or more than 70 days after May 4, 2017, notice by the stockholder must be received no earlier than the 120th day prior to the new meeting date and no later than the 90th day prior to the scheduled meeting date or, if less than 100 days' prior notice or public disclosure of the scheduled meeting date is given or made, the 10th day following the earlier of the date on which the notice of such meeting was mailed to stockholders or the date on which public announcement of the date of the 2017 Annual Meeting is first made by Jones Energy. Our Bylaws require that certain information and acknowledgments with respect to the proposal or the nominee, as applicable, and the stockholder making the proposal or the nomination be set forth in the notice. Our Bylaws have been publicly filed with the SEC and can also be found on our website at *www.jonesenergy.com* in the Corporate Governance section of our Investor Relations webpage.

Q: What should I do if I get more than one proxy or voting instruction card?

A: Stockholders may receive more than one set of voting materials, these proxy materials and multiple proxy cards or voting instruction cards. For example, stockholders who hold shares in more than one brokerage account may receive separate sets of proxy materials for each brokerage account in which shares are held. Stockholders of record whose shares are registered in more than one name will receive more than one set of proxy materials. You should vote in accordance with all sets of proxy materials you receive relating to our Annual Meeting to ensure that all of your shares are counted.

Q: How do I obtain a separate set of proxy materials or request a single set for my household?

A: We have adopted a procedure approved by the SEC called "householding." Under this procedure, stockholders who have the same address and last name will receive only one copy of the proxy materials unless one or more of these stockholders notifies us that they wish to continue receiving individual copies. This procedure reduces our printing costs and postage fees. Each stockholder who participates in householding will continue to be able to access or receive a separate proxy card.

If you are a registered stockholder and wish to receive a separate set of proxy materials, please request the additional copy by contacting our transfer agent, American Stock Transfer & Trust Company, LLC, by telephone at 1-888-776-9962 (U.S.) or 1-718-921-8562 (outside the U.S.), or by email at info@amstock.com. If you hold your shares beneficially and wish to receive a separate set of proxy materials, please contact your bank or broker. If any stockholders in your household wish to receive a separate annual report and a separate proxy statement in the future, they may contact Investor Relations, Jones Energy, Inc., 807 Las Cimas Parkway, Suite 350, Austin, Texas 78746. They may also send an email to Investor Relations at ir@jonesenergy.com. Other stockholders who have multiple accounts in their names or who share an address with other stockholders can authorize us to discontinue mailings of multiple annual reports and proxy statements by contacting Investor Relations.

PROPOSAL ONE:
ELECTION OF CLASS III DIRECTORS

At the recommendation of the Nominating and Corporate Governance Committee of the Board (the "Nominating Committee"), the Board has nominated the following individuals for election as Class III directors of the Company to serve for a three year term beginning at the Annual Meeting and expiring in 2019 and until either they are re-elected or their successors are elected and qualified:

Mr. Alan D. Bell
Mr. Gregory D. Myers

Messrs. Bell and Myers are currently serving as directors of the Company. Additional information about the nominees, including biographical information and qualifications, is contained below under the caption "Board of Directors and Corporate Governance—Information about the Directors and Nominees."

Unless otherwise instructed, the proxy holders will vote the proxies received by them **FOR** each of Messrs. Bell and Myers. If the nominees are unable or decline to serve as a director at the time of the Annual Meeting, the proxies will be voted for another nominee designated by the Board. We are not aware of any reason that a nominee would be unable or unwilling to serve as a director.

THE BOARD UNANIMOUSLY RECOMMENDS THAT STOCKHOLDERS VOTE "FOR" THE ELECTION OF EACH OF ALAN D. BELL AND GREGORY D. MYERS AS CLASS III DIRECTORS.

BOARD OF DIRECTORS AND CORPORATE GOVERNANCE

Board Structure

Our business and affairs are managed under the direction of the Board. Our amended and restated certificate of incorporation provides that our Board consist of between 1 and 11 directors. Our Board currently consists of 7 directors. Pursuant to a Registration Rights and Stockholders Agreement, dated July 29, 2013 (the "Registration Rights and Stockholders Agreement"), Metalmark and the Jones Family Entities are each entitled to nominate two directors for election to the Board. The Registration Rights and Stockholders Agreement also requires the stockholders party thereto to take all necessary actions, including voting their shares of Common Stock, for the election of these nominees. Please see "Certain Relationships and Related Person Transactions—Registration Rights and Stockholders Agreement."

Our Board is divided into three classes, with one class being elected at each annual meeting of stockholders. Each director serves a three-year term, with termination staggered according to class. Jonny Jones, Howard I. Hoffen and Robb L. Voyles have been assigned to Class I, Mike S. McConnell and Halbert S. Washburn have been assigned to Class II and Alan D. Bell and Gregory D. Myers have been assigned to Class III. For as long as Metalmark or the Jones Family Entities are entitled to nominate two directors for election to the Board, each of their respective director nominees shall be assigned to a different class.

Information about the Directors and Nominees

Set forth below is information regarding our directors and the nominees as of March 1, 2016. All of the candidates for election at this meeting are currently serving as our directors.

Name	Age	Position
Class I		
Jonny Jones	56	Chairman of the Board and Chief Executive Officer
Howard I. Hoffen	52	Director
Robb L. Voyles	58	Director
Class II		
Mike S. McConnell	55	Director and President
Halbert S. Washburn	55	Director
Class III		
Alan D. Bell	70	Director
Gregory D. Myers	45	Director

Business Experience and Qualifications of Directors

Class I Directors (Current Terms Will Expire at the 2017 Annual Meeting)

Jonny Jones has served as Chairman of our board of directors since 2009 and as the principal executive officer of the company since 1988. Prior to founding the company in 1988, Mr. Jones worked for subsidiaries and affiliates of BP plc as a geologist. Mr. Jones is a third generation explorationist with over 30 years of experience in the oil and gas industry focusing on the U.S. mid-continent. Mr. Jones is currently Chairman of the Texas Oil and Gas Association and serves on the executive committee of the US Oil & Gas Association. He received the Ernst & Young Entrepreneur of the Year 2012 Award for Central Texas. He has previously served on the Advisory Council of the University of Oklahoma School of Geology and Geophysics and has been actively involved in fund raising efforts at the school. Mr. Jones is a member of the Independent Petroleum Association of America, where he previously served on the Board of Directors. He is also a member of the American Association of Petroleum Geologists. Mr. Jones holds a B.S. in Geology from the University of Oklahoma and an M.A. in Geology from the University of Texas at Austin. Because of his extensive knowledge of the oil and gas industry and our operations developed through his role as our founder, as well as his substantial business, leadership and management experience, we believe that Mr. Jones is a valuable member of our Board.

Howard I. Hoffen has served on our board of directors since December 2009. Mr. Hoffen is currently the Chairman, Chief Executive Officer, and a Managing Director of Metalmark Capital II LLC, a private equity firm which he joined as a founding member in 2004. Prior to that, Mr. Hoffen served as Chairman and Chief Executive Officer of Morgan Stanley Capital Partners from 2001 to 2004, after having performed various roles in the private equity group since he joined Morgan Stanley in 1985. He also serves as a Director of EnerSys, Pacific Coast Energy Holdings LLC (the general partner of Pacific Coast Oil Trust) and several private companies. Mr. Hoffen received an M.B.A. degree from Harvard Business School and a B.S. degree from Columbia University. We believe that Mr. Hoffen's many years of investing experience, as well as his in-depth knowledge of the oil and gas industry generally, and Jones Energy in particular, provide him with the necessary skills to be a member of the Board of Jones Energy.

Robb L. Voyles has served on our board of directors since July 2014. Mr. Voyles currently serves as Executive Vice President and General Counsel for Halliburton. Prior to joining Halliburton in September 2013, Mr. Voyles was a senior partner at Baker Botts L.L.P. where he had practiced law since 1987 and where he served as the Chair of the Litigation Department and a member of its executive committee. He holds a Juris Doctor degree, magna cum laude, from the University of Michigan Law School and a B.B.A. in accounting, summa cum laude, from the University of Dayton. We believe that Mr. Voyles' experience within the legal profession and his current role as an executive in the energy industry provide him with the necessary skills to be a valuable member of the Board of Jones Energy.

Class II Directors (Current Terms Will Expire at the 2018 Annual Meeting)

Mike S. McConnell has served as the President of the company since 2004 and as a director since 2009. Mr. McConnell has over 30 years of domestic and international energy experience. Prior to joining the company in 2004, he served in senior management positions in a wide variety of areas in the energy business, including as the Chief Executive Officer of the Generation and Production Group for Enron Corp during bankruptcy from 2002 until 2003. He was the Chief Executive Officer of Enron Global Markets, LLC from 2000 until 2001. Prior to these assignments, Mr. McConnell served in the technology area for the company as Vice Chairman and Chief Operating Officer for Enron NetWorks and Chief Executive Officer of Global Technology from 1999 to 2000 and as President of Houston Pipe Line and Louisiana Resources Company from 1997 until 1999. He served as the chairman of the Price Business School Board of Advisors for the University of Oklahoma from 2010 until 2012 and is currently Vice Chairman of the Natural Gas Committee and a Director of the Independent Petroleum Association of America. Mr. McConnell graduated from the University of Oklahoma in 1982 with a B.B.A. in Petroleum Land Management with an emphasis on Law. Because of his wide-ranging experience in the oil and gas industry, including his financial management expertise, we believe Mr. McConnell is a valuable member of our Board.

Halbert S. Washburn has served as a director of the company since September 2013 and as the Chief Executive Officer of BreitBurn GP, LLC, the general partner of BreitBurn Energy Partners, L.P. ("BreitBurn"), since April 2010. Prior to these positions, he served as Co-Chief Executive Officer and a director of BreitBurn GP, LLC from March 2006 until April 2010 and was the chairman of the board of directors of BreitBurn GP, LLC from July 2008 to April 2010. Mr. Washburn also currently serves as the President and a director of Pacific Coast Energy Holdings LLC, the indirect owner of Pacific Coast Energy Company LP ("PCEC"), the predecessor to BreitBurn, and is the co-founder and was the Co-Chief Executive Officer of PCEC's predecessors from 1988 to 2012. Since December 2005, Mr. Washburn has served as a member of the board of directors and the compensation committee of Rentech, Inc., a publicly traded alternative fuels company. Mr. Washburn also served on the audit committee of Rentech, Inc. from 2005 until 2012. In June 2011, he was appointed Chairman of the Rentech, Inc. board of directors. From July 2011 to April 2015, Mr. Washburn served on the board of directors of Rentech Nitrogen Partners, L.P., a nitrogen fertilizer company formed by Rentech, Inc. as a publicly traded master limited partnership. He has been a member of the California Independent Petroleum Association since 1995 and served as chairman of the executive committee of the board of directors from 2008 to 2010. He has also served as a board member, including chairman of the board of directors, of the Stanford University Petroleum Investments Committee. Mr. Washburn holds a B.S. degree in Petroleum Engineering from Stanford University. Because of his distinguished career as an executive in the oil and gas industry and his more than 25 years of management experience in the industry, the Board has determined that Mr. Washburn's experience serving on boards of directors of both public and private companies allows him to provide the company with a variety of perspectives on corporate governance and other issues.

Class III Directors (Current Terms Will Expire at the 2016 Annual Meeting)

Alan D. Bell has served as a director of the company since July 2013. Mr. Bell is a retired senior audit partner in the energy industry. Prior to his retirement in 2006, Mr. Bell served as the Director of the Southwest Area Energy Practice at Ernst & Young LLP since 1998, after having performed various

roles in the firm since joining in 1973. Mr. Bell began his career as a petroleum engineer at Chevron Oil Company from 1969 to 1972. Mr. Bell currently serves as a director and audit committee chair of Approach Resources Inc., an exploration and development company. Mr. Bell is a director of the National Association of Corporate Directors (NACD)—North Texas Chapter. Mr. Bell is a NACD Board Leadership Fellow. Mr. Bell previously served as a director of Dune Energy, Inc. from May 2007 until January 2012, Toreador Resources Corporation from August 2006 until June 2009 and Central Energy GP LLC from November 2013 to December 2015. Mr. Bell also served as the Chief Restructuring Officer of Energy Partners Ltd. (now known as EPL Oil & Gas, Inc.) from March to September 2009. Mr. Bell was hired by the Board of Directors of Energy Partners to manage daily operations, reduce costs, negotiate a pre-arranged bankruptcy and manage the company during a complex Chapter 11 process. Mr. Bell is a member of the American Institute of Certified Public Accountants, the Texas Society of Certified Public Accountants and the Society of Petroleum Engineers. Mr. Bell earned a Petroleum Engineering degree from the Colorado School of Mines and MBA from Tulane University. We believe that Mr. Bell's financial and accounting experience and deep technical knowledge as an engineer make him a valuable member of our Board.

Gregory D. Myers has served on our board of directors since December 2009. Mr. Myers is a Managing Director of Metalmark Capital II LLC, a private equity firm which he joined as a founding member in 2004. Prior to that, Mr. Myers was a senior investment professional at Morgan Stanley Capital Partners from 1998 until 2004. Mr. Myers also serves as a director of Pacific Coast Energy Holdings LLC (the general partner of Pacific Coast Oil Trust, NYSE: ROYT) and several private companies in the energy industry. Previously, Mr. Myers served as a Director and Chairman of the Compensation Committee and Member of the Corporate Governance and Nominating Committee for Union Drilling, Inc. (NASDAQ: UDRL). He has a B.A. and B.S. from the University of Pennsylvania and an M.B.A. from the Harvard Business School. We believe that Mr. Myers' extensive investing and financial experience and knowledge of the oil and gas industry and our operations provide him with the necessary skills to be a member of our Board.

No family relationship exists among any of the directors, nominees or executive officers. Except with respect to the rights of Metalmark and the Jones Family Entities to nominate directors for election pursuant to the Registration Rights and Stockholders Agreement, no arrangement or understanding exists between any director, nominee, or executive officer and any other person pursuant to which any director, nominee or executive officer was selected as a director, nominee or executive officer of the Company.

Meetings of the Board

The Board met five times during 2015. Jones Energy's directors, on average, attended approximately 95 percent of Board and applicable committee meetings during 2015. No director attended less than 75 percent of such meetings. Additionally, while the Company has no formal policy regarding director attendance at its annual meeting of stockholders, Jones Energy's directors are encouraged to attend the Company's annual meetings. All of our seven directors attended the 2015 annual meeting of stockholders.

The non-management members of the Board regularly hold executive sessions, and the independent directors hold executive sessions at least annually. The Chairman of the Audit Committee, currently Alan Bell, presides over any executive session of the Board in which the members of our management are not present.

Corporate Governance

The Board acts as the ultimate decision-making body of the Company and advises and oversees management, who are responsible for the day-to-day operations and management of the Company. In carrying out its responsibilities, the Board reviews and assesses the Company's long-term strategy and its strategic, competitive and financial performance. The Board has adopted corporate governance guidelines that serve as a flexible framework within which the Board and its committees operate. These guidelines cover a number of areas including the size and composition of the board, board membership criteria and director qualifications, director responsibilities, board agenda, roles of the chairman of the board, chief executive officer and presiding director, meetings of independent directors, committee responsibilities and assignments, board member access to management and independent advisors, director communications with third parties, director compensation, director orientation and continuing education, evaluation of senior management and management succession planning. A copy of our corporate governance guidelines can be found on our website at *www.jonesenergy.com* in the Corporate Governance section of our Investor Relations webpage.

Director Independence

The Board has affirmatively determined that Messrs. Voyles, Bell, Hoffen, Myers and Washburn are independent directors under the applicable rules of the New York Stock Exchange (the "NYSE"), and that Messrs. Voyles, Bell and Washburn are also independent directors as such term is defined in Rule 10A-3(b)(1) under the Exchange Act for purposes of their service on the Audit Committee.

Board Committees

The Board has three standing committees: the Audit Committee, the Compensation Committee, and the Nominating Committee. The Board has adopted a written charter for each committee that sets forth the committee's purpose, composition, authority and responsibilities. Each charter can be found on our website at *www.jonesenergy.com* in the Corporate Governance section of our Investor Relations webpage.

Audit Committee

The Audit Committee has the authority to, among other things:

- approve and retain the independent registered public accounting firm to conduct the annual audit of our books and records and approve the audit fees to be paid;
- review the independence and performance of the independent registered public accounting firm;
- review the proposed scope and results of the audit;
- review and pre-approve the independent registered public accounting firm's audit and non-audit services rendered;
- review and approve transactions between us and our directors, officers and affiliates;
- oversee internal audit functions and our compliance with legal and regulatory requirements; and
- prepare the report of the audit committee that SEC rules require to be included in our annual meeting proxy statement.

Our Audit Committee is currently comprised of Messrs. Voyles, Bell and Washburn. Mr. Bell serves as chair of the Audit Committee and also qualifies as an "audit committee financial expert" as such term has been defined by the SEC in Item 401(h)(2) of Regulation S-K. Our Board has affirmatively determined that Messrs. Voyles, Bell and Washburn meet the definition of an "independent director" for the purposes of serving on the Audit Committee under applicable SEC and NYSE rules. All members of our Audit Committee meet the requirements for financial literacy under the applicable rules and regulations of the SEC and the NYSE. Members of the Audit Committee are limited to serving on no more than two other public company audit committees, unless expressly

approved by the Board after determining that simultaneous service would not impair the ability of such member to effectively serve on the Company's Audit Committee. Our Audit Committee met four times in 2015.

Compensation Committee

The primary purposes of our Compensation Committee are to, among other things:

- review and recommend the compensation arrangements for officers and other employees;
- establish and review general compensation policies with the objective to attract and retain superior talent, to reward individual performance and to achieve our financial goals; and
- administer our incentive compensation and benefits plans, including our stock incentive plan.

The Compensation Committee is delegated all authority of the Board as may be required or advisable to fulfill the purposes of the Compensation Committee. The Compensation Committee may form and delegate some or all of its authority to subcommittees when it deems appropriate. Meetings may, at the discretion of the Compensation Committee, include members of the Company's management, other members of the Board, consultants or advisors, and such other persons as the Compensation Committee or its chairperson may deem necessary in an informational or advisory capacity.

The Compensation Committee reviews and approves corporate goals and objectives relevant to the compensation of the executive officers, evaluates the executive officers' performance at least annually in light of those goals and objectives, and determines the executive officers' compensation level based on this evaluation. In determining the long-term incentive component of the executive officers' compensation, the Compensation Committee should consider the Company's performance and relative stockholder return, the value of similar incentive awards to executive officers at comparable companies, the awards given to the Company's executive officers in past years and such other factors as the Compensation Committee deems appropriate and in the best interest of the Company.

Our Board annually considers the performance of our Chief Executive Officer. Meetings to determine the compensation of the Chief Executive Officer must be held in executive session. Meetings to determine the compensation of any officer of the Company, other than the Chief Executive Officer, may be attended by the Chief Executive Officer, but the Chief Executive Officer may not vote on these matters.

The Compensation Committee has the sole authority to retain, amend the engagement with, and terminate any compensation consultant to be used to assist in the evaluation of director, Chief Executive Officer or officer compensation, including employment contracts and change in control provisions. The Compensation Committee has sole authority to approve the consultant's fees and other retention terms and has authority to cause the Company to pay the fees and expenses of such consultants. In 2015, Frederic W. Cook & Co., Inc. ("F.W. Cook") provided the Compensation Committee with objective and expert analyses, independent advice, and information with respect to executive compensation. F.W. Cook did not provide other consulting services to the Compensation Committee. The Compensation Committee concluded that no conflict of interest exists that would prevent F.W. Cook from independently representing the Compensation Committee.

Our Compensation Committee is currently comprised of Messrs. Bell, Myers and Washburn, with Mr. Myers serving as the chair. Our Board has affirmatively determined that Messrs. Bell, Myers and Washburn meet the definition of an "independent director" for the purposes of serving on the Compensation Committee under applicable NYSE rules. Our Compensation Committee met four times in 2015.

Nominating and Corporate Governance Committee

The primary purposes of our Nominating Committee are to, among other things:

- identify, evaluate and recommend qualified nominees for election to the Board;
- develop, recommend to the Board and oversee a set of corporate governance principles applicable to our company;
- oversee the evaluation of the Board and management; and
- develop and maintain a management succession plan.

In evaluating the suitability of candidates, the Board and the Nominating Committee take into account many factors. These factors may include, among other things, an individual's character, business experience, qualifications, attributes and skills such as relevant industry knowledge, specific experience with technology, accounting, finance, leadership, operations, strategic planning, and international markets; independence; judgment; integrity; the ability to commit sufficient time and attention to the activities of the Board; diversity of occupational and personal backgrounds on the Board; and the absence of potential conflicts with the Company's interests.

The Board believes that its membership should reflect a diversity of experience, gender, race, ethnicity and age, and the Nominating Committee's charter requires that it take into account such diversity in making director recommendations. The Nominating Committee will assess the effectiveness of this approach as part of its annual review of its charter and our Corporate Governance Guidelines. The Nominating Committee will select qualified nominees and review its recommendations with the Board, which will decide whether to invite the nominees to join the Board. When evaluating the suitability of an incumbent director for nomination or re-election, the Board and the Nominating Committee also consider the director's past performance, including attendance at meetings and participation in and contributions to the activities of the Board.

Our Nominating Committee is currently comprised of Messrs. Bell, Voyles and Washburn, with Mr. Voyles serving as the chair. Our Board has affirmatively determined that Messrs. Bell, Voyles and Washburn meet the definition of an "independent director" for the purposes of serving on the Nominating Committee under applicable NYSE rules. Our Nominating Committee met one time in 2015.

Compensation Committee Interlocks and Insider Participation

None of our officers or employees will be members of the Compensation Committee. None of our executive officers serve on the board of directors or compensation committee of a company that has an executive officer that serves on our Board or Compensation Committee. No member of our Board is an executive officer of a company in which one of our executive officers serves as a member of the board of directors or compensation committee of that company.

Code of Business Conduct and Ethics

We have adopted a code of business conduct and ethics that applies to all of our employees, officers and directors, including those officers responsible for financial reporting. These standards are designed to deter wrongdoing and to promote honest and ethical conduct. The code of business conduct and ethics is available on our website at *www.jonesenergy.com* in the Corporate Governance section of our Investor Relations webpage. Any waiver of the code for directors or executive officers may be made only by our Board or a Board committee to which the Board has delegated that authority and will be promptly disclosed to our stockholders as required by applicable U.S. federal securities laws and the corporate governance rules of the NYSE. Amendments to the code must be approved by our Board and will be promptly disclosed (other than technical, administrative or non-substantive changes).

Any amendments to the code, or any waivers of its requirements, for which disclosure is required, will be disclosed on our website.

Director Nominations

Subject to the rights of Metalmark and the Jones Family Entities to nominate directors to the Board, the Board is responsible for selecting candidates to fill vacancies on the Board and for nominating individuals for election as directors by the stockholders, in each case, based on the recommendation of the Nominating Committee. The Nominating Committee considers recommendations for Board candidates submitted by stockholders using substantially the same criteria it applies to recommendations from the Nominating Committee, current directors or members of management. Stockholders may submit recommendations by providing the person's name and appropriate background and biographical information in writing to the Nominating Committee at Jones Energy, Inc., Attn: Nominating and Corporate Governance Committee, 807 Las Cimas Parkway, Suite 350, Austin, Texas 78746. Stockholders who want to nominate directors for election at Jones Energy's next annual meeting of stockholders must follow the procedures described in the Company's Bylaws, which are available on our website at *www.jonesenergy.com* in the Corporate Governance section of our Investor Relations webpage.

Contacting the Board, the Chairman and Other Independent Directors

Stockholders or interested parties wishing to communicate directly with our Board, any individual director, the Chairman of the Board, or any non-management or independent directors as a group may do so by writing to them care of Jones Energy's Corporate Secretary at 807 Las Cimas Parkway, Suite 350, Austin, Texas 78746. The Corporate Secretary will forward appropriate communications. Any concerns reported related to accounting, internal accounting controls or auditing matters will be promptly brought to the attention of the Chair of the Audit Committee as appropriate. For more information on how to contact our Board, please see our Corporate Governance Guidelines located within the Corporate Governance section on the Investor Relations tab of our webpage at *www.jonesenergy.com*.

Board Leadership and Role in Risk Oversight

Combination of Offices of Chairman of the Board and Chief Executive Officer

The Nominating Committee believes that Mr. Jones serving as both Chairman of the Board and Chief Executive Officer is the most effective leadership structure for us because it enables our Chief Executive Officer to act as a bridge between management and the Board, helping both to act with a common purpose. The Board believes the combined role of Chairman and Chief Executive Officer promotes unified leadership and direction for the Company, which allows for a single, clear focus for management to execute the Company's strategy and business plans. As Chief Executive Officer, the Chairman is best suited to ensure that critical business issues are brought before the Board, which enhances the Board's ability to develop and implement business strategies.

Risk Oversight

The Board provides oversight of our major risk exposures and the steps management has taken to monitor and manage such exposures. The Audit Committee is primarily responsible for oversight of the quality and integrity of the Company's financial reporting process, internal controls over financial reporting and the Company's compliance programs. The Compensation Committee is responsible for reviewing compensation-related risks. The Nominating Committee is responsible for oversight of the Company's corporate governance programs, including the code of ethics and business conduct. Management regularly reports to the Board and its committees on the risks that the Company may face and the steps that management is taking to mitigate those risks.

EXECUTIVE OFFICERS

The executive officers of the Company and their ages and titles as of March 1, 2016 are set forth below.

Name	Age	Position
Jonny Jones	56	Chief Executive Officer
Mike S. McConnell	55	President
Eric Niccum	45	Executive Vice President and Chief Operating Officer
Robert J. Brooks	53	Executive Vice President and Chief Financial Officer
Jeff Tanner	53	Executive Vice President—Geosciences

Set forth below is a description of the backgrounds and business experience of the executive officers of the Company. The backgrounds and business experience of Jonny Jones and Mike S. McConnell are set forth above under "Directors and Corporation Governance—Business Experience and Qualifications of Directors."

Eric Niccum has served as our Executive Vice President and Chief Operating Officer since joining the company in 2011. Mr. Niccum has over 20 years of energy and petroleum experience, starting his career with Amoco in a variety of engineering roles. Following the BP/Amoco merger, he worked in Deep Water Gulf of Mexico in 2001, returning to the Mid-Continent region as a Resource Manager and New Well Delivery Manager for BP from 2005 to 2011, overseeing activities in the Anadarko and Arkoma basins. Mr. Niccum is a graduate of Purdue University and holds a B.S. in Mechanical Engineering.

Robert J. Brooks joined the company as our Executive Vice President and Chief Financial Officer in 2013. He has 25 years of corporate finance experience in the oil and gas industry. Mr. Brooks' prior experience includes investment banking leadership of M&A advisory and capital markets transactions and private equity investments, primarily in the upstream energy sector. Most recently, Mr. Brooks led the energy investment banking efforts at Whiteface Capital LLC from 2012 until 2013 and Focus Capital Group, Inc. from 2010 until 2012. From 2004 until 2010, Mr. Brooks served as the Senior Managing Director and Head of Macquarie Capital's U.S. Natural Resources investment banking practice, which he founded in 2004. Mr. Brooks also served as President and Board Member of Macquarie Longview Holdings, an E&P company owned and controlled by Macquarie. Prior to Macquarie, Mr. Brooks was a Principal in the Energy Group at Banc of America Securities, and began his investment banking career in the Energy Investment Banking Group at Salomon Brothers. Mr. Brooks holds a B.S. in Mechanical Engineering from the Massachusetts Institute of Technology, or MIT, an M.S. in Mechanical Engineering from Stanford University, and an M.S. in Management from the Sloan School of Management at MIT.

Jeff Tanner joined the company in 2014 and serves as Executive Vice President—Geosciences. Mr. Tanner has over 27 years of diverse technical and managerial experience in the oil and gas industry. Prior to joining Jones Energy, Mr. Tanner was Vice President, Exploration for Southwestern Energy. During his career, Mr. Tanner has held a variety of management and technical positions for Laredo Petroleum, Cabot Oil and Gas, and Noble Energy. He began his career with Royal Dutch Shell plc ("Shell") in Houston. Mr. Tanner is a member of the American Association of Petroleum Geologists and the Houston Geological Society. He holds a B.S. in Geology from Texas A&M and an M.S. in Geology from the University of Houston.

EXECUTIVE COMPENSATION

We are an "emerging growth company," as defined in the Jumpstart Our Business Startups Act of 2012 (the "JOBS Act"). As an emerging growth company, we have reduced disclosure obligations regarding executive compensation compared to companies that are not emerging growth companies and we are exempt from the requirement of holding advisory "say-on-pay" votes on executive compensation. Under the JOBS Act, we will remain an emerging growth company until the earliest of (1) the last day of the fiscal year during which we have total annual gross revenues of $1 billion or more; (2) the last day of the fiscal year following the fifth anniversary of the completion of our initial public offering ("IPO"); (3) the date on which we have, during the previous three-year period, issued more than $1 billion in non-convertible debt; and (4) the date on which we are deemed to be a "large accelerated filer" under the Exchange Act.

Compensation of Named Executive Officers

The following discussion of compensation arrangements of our named executive officers for 2015 (as set forth in the Summary Compensation Table and defined below) should be read together with the compensation tables and related disclosures set forth below.

2015 Summary Compensation Table

The following tables provide information about the compensation of our named executive officers. In accordance with SEC rules, our named executive officers are our Chief Executive Officer and our two other most highly compensated executive officers for the year ended December 31, 2015.

Name and Principal Position	Year	Salary ($)	Non-Equity Incentive Plan Compensation ($)(1)	Stock Awards ($)(2)	All Other Compensation ($)(3)	Total ($)
Jonny Jones	2015	$500,000	$550,000	$2,000,000	$ 62,699]	$3,112,699
Chief Executive Officer and Chairman	2014	$494,792	$390,000	$2,296,805	$ 61,100	$3,242,697
Mike S. McConnell	2015	$380,000	$355,300	$ 999,400	$400,616	$2,135,316
President and Director	2014	$373,750	$251,940	$ 999,995	$ 50,595	$1,676,280
Eric Niccum . . . . *Executive Vice President and Chief Operating Officer*	2015	$340,000	$299,200	$ 901,000	$127,587	$1,667,787

(1) The amounts reported in this column reflect the amount paid to each executive with respect to performance in 2015 and 2014 under the Jones Energy, Inc. 2013 Short-Term Incentive Plan.

(2) The amounts in this column for 2015 represent the aggregate grant date fair value computed in accordance with FASB ASC Topic 718 of restricted stock units and performance units awarded under the Jones Energy, Inc. 2013 Omnibus Incentive Plan. The value of performance units is the value at the grant date based upon the probable outcome of the applicable performance conditions.

Additionally, the 2014 amount for Mr. Jones includes the value of Monarch Natural Gas Holdings, LLC units ("Monarch Units") that corresponded to nominal units representing Monarch Units ("Phantom Units") forfeited by a departing employee during the year. Upon forfeiture the units immediately vested to Mr. Jones and were valued at $100.00 per unit pursuant to the Monarch Equity Plan and based on our knowledge of other equity transactions of Monarch Natural Gas Holdings, LLC, a private company.

(3) The amounts in this column include the following: matching contributions under our 409A savings plan for Messrs. Jones, McConnell, and Niccum; country club association dues for Messrs. Jones and McConnell; payments associated with leasing company vehicles for Messrs. Jones and McConnell; and payments associated with auto insurance policies on the company vehicles for Messrs. Jones and McConnell. For Messrs. McConnell and Niccum, also included in 2015 are cash bonus payments of $353,895 and $111,987, respectively, from a distribution received by the Company from Monarch Units held for their benefit under the Monarch Equity Plan.

Our named executive officers do not have contractual rights to employment by us and may be terminated with or without cause at any time. Messrs. Jones, McConnell, Brooks and Niccum entered into agreements with us containing confidentiality, non-competition, non-solicitation and non-disparagement obligations with respect to us that survive beyond their employment with us.

Outstanding Equity Awards at 2015 Fiscal Year-End

The following table reflects all unvested outstanding equity awards of our named executive officers as of December 31, 2015.

		STOCK AWARDS			
Name	**Grant Date**	**Number of Units or Shares of Stock That Have Not Vested (#)**	**Market Value of Units or Shares of Stock That Have Not Vested(4) ($)**	**Equity Incentive Plan Awards: Number of Unearned Shares That Have Not Vested (#)**	**Equity Incentive Plan Awards: Payout Value of Unearned Shares That Have Not Vested(4) ($)**
Jonny Jones	5/20/2014	47,731(2)	$183,764		
	5/20/2014			71,598(3)	$275,652
	4/29/2015	115,075(2)	$443,039		
	4/29/2015			115,075(3)	$443,039
Mike S. McConnell . . .	4/22/2013	90,937(1)	$350,107		
	5/20/2014	23,866(2)	$ 91,884		
	5/20/2014			35,798(3)	$137,822
	4/29/2015	115,075(2)	$221,386		
	4/29/2015			115,075(3)	$221,386
Eric Niccum	8/22/2011	7,841(1)	$ 30,188		
	4/22/2013	39,198(1)	$150,942		
	5/20/2014	19,093(2)	$ 73,508		
	5/20/2014			28,639(3)	$110,260
	4/29/2015	51,841(2)	$199,588		
	4/29/2015			51,841(3)	$199,588

(1) Represents unvested indirectly owned JEH LLC units and Class B Shares that together, after vesting, are exchangeable on a one-for-one basis for Class A Shares pursuant to the terms of the Exchange Agreement. The unvested indirectly owned JEH LLC units and Class B Shares vest in five equal installments on each anniversary of the date such JEH LLC units were granted.

(2) Represents unvested restricted stock unit awards. Each restricted sock unit represents the contingent right to receive one share of Class A common stock upon vesting of the unit. Shares vest in three equal installments annually on April 1st.

(3) Represents unvested performance unit awards based on achieving a target threshold of 100% vesting. Each vested performance unit is exchangeable for one share of the Company's Class A common stock. Upon completion of the three-year performance period ending December 31st of the second year following the year of the grant date, each officer will vest in a number of performance units. The number of performance units in which each officer vests will range from 0% to 200% based on the Company's total shareholder return relative to an industry peer group over the three-year performance period.

(4) Reflects the payout values at December 31, 2015 of the unvested awards in the previous column. The payout value is determined by multiplying the number of unvested awards by $3.85, the closing price of a Class A Share on December 31, 2015.

Jones Energy, Inc. 2013 Omnibus Incentive Plan

Shortly before our IPO, our Board of Directors adopted, and our stockholders approved, the Jones Energy, Inc. 2013 Omnibus Incentive Plan (the "LTIP"), effective upon consummation of the IPO. Our LTIP is designed to attract and retain employees, consultants and non-employee directors and to encourage the sense of proprietorship of such individual and to stimulate the active interest of such persons in the development of our success. To accomplish this goal, equity, equity-based and cash awards may be made under the LTIP to employees and consultants of the Company and our affiliates and to our directors.

The LTIP is administered by our Compensation Committee. As of December 31, 2015, there were 2,303,615 Class A Shares available for issuance under the LTIP, all of which may be issued to our employees and directors. The LTIP provides for the issuance of stock options (incentive stock options and nonstatutory stock options), restricted stock, performance awards, restricted stock units, bonus stock awards, stock appreciation rights, dividend equivalents, and cash awards. With respect to equity awards made under the LTIP, no employee may be granted during a single calendar year (i) stock options or stock appreciation rights that are exercisable for more than 1,000,000 shares of our common stock; (ii) performance-based awards settled in our Class A Shares or other stock awards covering or relating to more than 1,000,000 shares of our Class A Shares or (iii) cash awards or performance-based awards settled solely in cash having a grant date value in excess of $5,000,000. No non-employee director may be granted during a single calendar year awards having a value determined on the grant date in excess of $500,000.

Jones Energy, Inc. 2013 Short-Term Incentive Plan

Shortly before our IPO, our Board adopted, and our stockholders approved, the Jones Energy, Inc. 2013 Short Term Incentive Plan ("STIP"), effective upon consummation of the IPO. Annual cash bonus awards may be made to our employees under the STIP that are based on the achievement of certain business objectives and other criteria established by the Compensation Committee, which is the administrator of the STIP.

Under the STIP, with respect to awards based on the achievement of business objectives, our Compensation Committee establishes objective goals generally no later than 90 days after the commencement of service to which the performance goals relate and prior to the completion of 25% of the performance period, and in any event, while the outcome is substantially uncertain. A performance goal may be based on one or more business criteria that apply to the individual, one or more of our business units, or the company as a whole. Performance goals are based on one or more of the financial or operational factors, as applied to the company or a business unit, as applicable, set forth in the STIP. Prior to the payment of any compensation based on the achievement of the performance goals, the Compensation Committee must certify in writing that applicable performance goals were, in fact, satisfied. The Compensation Committee, in its sole discretion, may decrease the amount payable pursuant to an STIP award, but the Compensation Committee does not have discretion to increase the amount payable to a participant who is a "covered employee" as defined under Code Section 162(m) in a manner inconsistent with the requirements for qualified performance-based compensation under Code Section 162(m). No participant may be granted performance awards that would result in the payment of more than $5,000,000 per plan year.

Monarch Equity Plan

Prior to our IPO, the Board adopted the Monarch Equity Plan to provide for grants of Phantom Units for the benefit of certain officers who performed services for us. As of December 31, 2015, we have granted all 26,192 Phantom Units available for grant under the Monarch Equity Plan, including certain grants of the Phantom Units to our executive officers in 2013 as follows: 11,723 Phantom Units were granted to Mike S. McConnell, 1,072 Phantom Units were granted to Robert J. Brooks, and 3,710 Phantom Units were granted to Eric Niccum.

The Phantom Units will vest 20% per year on each of the first, second, third, fourth and fifth anniversary of the grant date, provided that the participant remains in continuous employment with the company through each applicable vesting date. Within 30 days of a vesting date, a participant will receive an assignment of the number of Monarch Units corresponding to the Phantom Units vesting on such date. If a participant's employment with us terminates for any reason, (i) all unvested Phantom Units will be immediately forfeited by the participant, and the Monarch Units underlying such forfeited Phantom Units will be assigned to Jonny Jones within 30 days following the forfeiture date and (ii) Jonny Jones shall have a call option to purchase any or all of the Monarch Units issued to such participant in respect of vested Phantom Units at the fair market value determined by the Board for Monarch Units as of the most recent valuation date coincident with or immediately preceding the date such call option is exercised.

On January 1, 2015, pursuant to the terms of the Monarch Equity Plan, Jonny Jones received a distribution of Monarch Units having a value of approximately $296,800 in connection with the forfeiture of Phantom Units issued under the Monarch Equity Plan by a terminated employee. In May 2015, the Company received a cash distribution associated with the Monarch Units held for the benefit of participants in the Monarch Equity Plan. The full amount was subsequently paid to the plan participants as a bonus during the year, including Mike S. McConnell and Eric Niccum.

Deferred Compensation Plan

On October 17, 2013, our Compensation Committee adopted the Jones Energy, LLC Executive Deferral Plan (the "Deferred Compensation Plan"), under which key management or highly compensated employees that are selected by the Compensation Committee may defer receipt of their compensation, including up to 50% of their base salaries and up to 100% of their bonuses, effective as of October 1, 2013. The current eligible employees are Jonny Jones, Mike S. McConnell, Robert J. Brooks, Eric Niccum and Jeff Tanner.

To participate, eligible employees must make irrevocable deferral elections no later than December 31st (or such earlier date selected by the Compensation Committee) of the year preceding the year during which the election applies. A participant's compensation deferred under the Deferred Compensation Plan is evidenced in a notional or bookkeeping account established and maintained by the Company. Participant contributions are fully vested at all times and credited with income, expense, gains and losses in accordance with the deemed investment of the participant's account in the investment funds offered under our 401(k) plan, as elected by the participant. These investment funds are for measurement purposes only, and a participant's election of any such investment fund is hypothetical and is not an actual investment of his or her Deferred Compensation Plan account in any such investment funds. The Deferred Compensation Plan is an "unfunded" plan for state and federal tax purposes, and participants have the rights of unsecured creditors of the Company with regard to their Deferred Compensation Plan accounts. The Company has established a "rabbi trust" and makes contributions to that trust from time to time that may be used to make payments under the Deferred Compensation Plan. All assets in the rabbi trust remain the property of the Company and subject to the claims of the Company's creditors; the participants have no rights to the trust funds other than as an unsecured creditor of the Company.

The account balance of a participant will be distributed to the participant in a single lump-sum payment upon the earlier of the 30th day following the date of (i) the participant's termination of employment for any reason or (ii) the participant's death or disability (as defined in the Deferred Compensation Plan). Distributions will be made in cash unless the Committee determines other property should be distributed. The foregoing notwithstanding, if a participant is a "specified employee" within the meaning of Section 409A of the Internal Revenue Code, unless the distribution is due to the participant's death or disability, the participant's payment will be delayed for 6 months following the participant's termination date.

Potential Payments Upon Termination or Change in Control

The LTIP provides in the event of death, disability, retirement or change in control (as defined in the LTIP), the Compensation Committee may, in its discretion (which may be provided in the award agreement), accelerate the vesting or exercisability of an award, eliminate or make less restrictive any restrictions contained in an award, waive any restriction or other provision of the LTIP or an award or otherwise amend or modify an award in any manner that is, in either case, (1) not materially adverse to the participant, (2) consented to by the participant or (3) as otherwise authorized under the LTIP; provided that the term of an option or SAR may not be extended to greater than 10 years from its original grant date.

DIRECTOR COMPENSATION

We believe that attracting and retaining qualified non-employee directors is critical to our future value growth and governance. Our non-employee directors receive:

- an annual cash retainer fee of $60,000, plus cash payments of $1,000 for each committee meeting attended; and
- a committee chairperson fee of $15,000; and
- an annual equity award for each non-employee director equal to a number of shares of restricted stock having a value of approximately $125,000 on the date of grant, based on the closing price of our Class A Shares on the date of grant.

Directors who are also our employees do not receive any additional compensation for their service on our Board. Each director is reimbursed for travel and miscellaneous expenses to attend meetings and activities of our Board of Directors or its committees.

2015 Director Compensation Table

The following table sets forth certain information with respect to our non-employee director compensation during the year ended December 31, 2015.

Name	Fees Earned or Paid in Cash ($)(1)	Restricted Share Awards ($)(2)	Total ($)
Howard I. Hoffen	$49,315	$98,375	$147,690
Gregory D. Myers	$52,315	$98,375	$150,690
Alan D. Bell	$67,644	$98,375	$166,019
Halbert S. Washburn	$55,315	$98,375	$153,690
Robb L. Voyles	$51,315	$98,375	$149,690

(1) Includes cash retainer, committee meeting fees and committee chair fees.

(2) Reflects the grant date fair value of the 13,476 shares of restricted Class A Shares awarded to each director on July 30, 2015 under the LTIP. The restricted Class A Shares vest on May 25, 2016.

AUDIT COMMITTEE REPORT

The information contained in this Audit Committee Report and references in this Proxy Statement to the independence of the Audit Committee members shall not be deemed to be "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended (the "Securities Act") or the Exchange Act, except to the extent that the Company specifically incorporates such information by reference in such filing.

The Company has determined that all current Audit Committee members are (1) independent, as defined in Section 10A of the Exchange Act, (2) independent under the standards set forth by the NYSE and (3) financially literate. In addition, Mr. Bell qualifies as an audit committee financial expert under the applicable rules promulgated pursuant to the Exchange Act. The Audit Committee is a separately designated standing committee of the Board established in accordance with Section 3(a)(58)(A) of the Exchange Act and operates under a written charter initially approved by the Board on July 10, 2013, which is reviewed annually.

Management is responsible for our system of internal controls and the financial reporting process. The independent accountants are responsible for performing an independent audit of our consolidated financial statements in accordance with auditing standards generally accepted in the United States of America and issuing a report thereon. The Audit Committee is responsible for monitoring (1) the integrity of our financial statements, (2) our compliance with legal and regulatory requirements, and (3) the independence and performance of our auditors.

The Audit Committee has reviewed and discussed with our management and the independent accountants the audited consolidated financial statements in our Annual Report on Form 10-K for the year ended December 31, 2015, including a discussion of the quality, not just the acceptability, of the accounting principles applied, the reasonableness of significant judgments and the clarity of disclosures in the consolidated financial statements. Management represented to the Audit Committee that our consolidated financial statements were prepared in accordance with accounting principles generally accepted in the United States of America. The Audit Committee discussed with the independent accountants matters required to be discussed by the Public Company Accounting Oversight Board's Auditing Standard No. 16, The Auditor's Communication With Those Charged With Governance.

Our independent accountants also provided to the Audit Committee the written disclosure required by applicable requirements of the Public Company Accounting Oversight Board regarding independent accountant's communications with the Audit Committee concerning independence. The Audit Committee discussed with the independent accountants that firm's independence.

Based on the Audit Committee's discussions with management and the independent accountants, and the Audit Committee's review of the representations of management and the report of the independent accountants to the Audit Committee, the Audit Committee recommended that the Board include the audited consolidated financial statements in our Annual Report on Form 10-K for the year ended December 31, 2015 filed with the SEC.

Audit Committee of the Board

Mr. Alan D. Bell, Chairman
Mr. Halbert S. Washburn, Member
Mr. Robb L. Voyles, Member

CERTAIN RELATIONSHIPS AND RELATED PERSON TRANSACTIONS

Each of the related party transactions described below was negotiated on an arm's length basis. We believe that the terms of such agreements are as favorable as those we could have obtained from parties not related to us.

IPO Related Agreements

In connection with our IPO on July 29, 2013, we entered into various agreements governing the relationship among us, the Pre-IPO Owners, our executive officers and certain of our directors. The following is a description of the material terms of these agreements, which description is qualified in its entirety by reference to the full text of the agreements which are filed with the SEC as exhibits to our periodic reports.

Registration Rights and Stockholders Agreement

In connection with the closing of the IPO, the Company entered into the Registration Rights and Stockholders Agreement with Metalmark and the Jones Family Entities. The Registration Rights and Stockholders Agreement grants each of Metalmark and the Jones Family Entities the right to nominate two members of the Board so long as Metalmark or the Jones Family Entities, as applicable, holds not less than 50% of the Common Stock that they held immediately following the IPO and the right to nominate one member of the Board so long as they hold not less than 20% of the Common Stock that they held immediately following the IPO. The Registration Rights and Stockholders Agreement also requires the stockholders party thereto to take all necessary actions, including voting their shares of Common Stock, for the election of these nominees.

In addition, the Registration Rights and Stockholders Agreement contains provisions with respect to demand registration rights and piggy-back registration rights. Pursuant to the Registration Rights and Stockholders Agreement, Metalmark and the Jones Family Entities have the right to require the Company, by written notice, to register the sale of any number of their shares of Common Stock and will each have the right to cause up to three such required or "demand" registrations. The Company is not obligated to effect 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 Shares (subject to certain exceptions) for the Company's own account, then it must give prompt notice to Metalmark 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.

In May 2015, Metalmark exercised one of its "demand" registrations under the Registration Rights and Stockholders Agreement to sell 5,000,000 of its Class A Shares in a secondary, underwritten offering (the "Secondary Offering") that closed on May 19, 2015. Pursuant to the terms of the Registration Rights and Stockholders Agreement, the Company was obligated to pay all fees and expenses related to the Secondary Offering, excluding underwriting fees, commissions, discounts and allowances, if any, and certain fees and disbursements of counsel to the underwriters. The Company did not receive any proceeds from the sale of Class A shares in the Secondary Offering. The total expenses paid by the Company in connection with the Secondary Offering was approximately $150,000.

Exchange Agreement

In connection with the closing of the IPO, the Company entered into the Exchange Agreement with JEH LLC and the Pre-IPO Owners. Pursuant to the Exchange Agreement, the Pre-IPO Owners and their permitted transferees have the right, subject to the terms of the Exchange Agreement, to exchange their JEH LLC Units (together with a corresponding number of Class B Shares) with

JEH LLC for Class A Shares on a one-for-one basis, subject to customary conversion rate adjustments for stock splits, stock dividends and reclassifications and other similar transactions.

Tax Receivable Agreement

As described in "Exchange Agreement" above the Pre-IPO Owners (and their permitted transferees) may exchange their JEH LLC units (together with a corresponding number of Class B Shares) for Class A Shares (on a one-for-one basis, subject to customary conversion rate adjustments for stock splits, stock dividends and reclassification and other similar transactions). JEH LLC has made an election under Section 754 of the Internal Revenue Code, pursuant to which each future exchange of JEH LLC units for Class A Shares (as well as any purchase of JEH LLC units for cash) is expected to result in an adjustment to the tax basis of the tangible and intangible assets of JEH LLC, and these adjustments will be allocated to us. The anticipated basis adjustments are expected to increase (for tax purposes) our depreciation, depletion and amortization deductions and may also decrease our gains (or increase our losses) on future dispositions of certain capital assets to the extent tax basis is allocated to those capital assets. Such increased deductions and losses and reduced gains may reduce the amount of tax that we would otherwise be required to pay in the future.

In connection with the Exchange Agreement described above, we entered into the Tax Receivable Agreement with JEH LLC and the Pre-IPO Owners. 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 pre-IPO owners' 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 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 LLC. 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. 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.

As of December 31, 2015 the Company had an estimated liability under the Tax Receivable Agreement to Mr. McConnell of $0.8 million and a de minimis liability to Mr. Niccum as a result of exchanges of Class B shares and JEH units made to date. In addition, the Company has estimated liability of approximately $35.6 million under the Tax Receivable Agreement to Metalmark related to the Secondary Offering. The Company does not anticipate that a material payment will be made during 2016.

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.

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. Under the Monarch agreement, the Company is paid a specified percentage of the value of the NGLs extracted and sold by Monarch, based on a set liquids recovery percentage, and the amount received from the sale of the residue gas, after deducting a fixed volume for fuel, lost and unaccounted for gas. The Company produced approximately 1.4 MMBoe of natural gas and NGLs for the year ended December 31, 2014 and 0.8 MMBoe of natural gas and NGLs for the year ended December 31, 2013, from the properties that became subject to the Monarch agreement. During the years ended December 31, 2014 and 2013, the Company recognized $37.0 million and $10.4 million, respectively, of revenue associated to the aforementioned natural gas and NGL production. Effective May 1, 2015, the rights to gather natural gas under the sale and purchase agreement transferred from Monarch to Enable Midstream Partners LP, ("Enable"), an unaffiliated third-party. Prior to closing of the transfer of these rights, the Company produced approximately 1.0 MMBoe of natural gas and NGLs for the year ended December 31, 2015 from the properties that became subject to the Monarch agreement for which the Company recognized $10.6 million of revenue. The revenue, for all years mentioned, is recorded in Oil and gas sales on the Company's Consolidated Statement of Operations. The initial term of the agreement, which remains unchanged by the transfer to Enable, runs for 10 years from the effective date of September 1, 2013.

At the time the Company entered into the 2013 Monarch agreement, Metalmark Capital owned approximately 81% of the outstanding equity interests of Monarch. In addition, Metalmark Capital beneficially owns in excess of five percent of the Company's outstanding equity interests and two of our directors, Howard I. Hoffen and Gregory D. Myers, are managing directors of Metalmark Capital.

In the year ended December 31, 2013, the Company paid an annual administration fee to Metalmark of $0.7 million. This amount was recorded in general and administration expense on the Company's Consolidated Statement of Operations. As a result of the IPO, this fee is no longer payable to Metalmark.

In connection with the Company's entering into the 2013 Monarch agreement, Monarch issued to JEH equity interests in Monarch, having an estimated fair value of $15 million, in return for marketing services to be provided throughout the term of the agreement. The Company recorded this amount as deferred revenue which is being amortized on an estimated units-of-production basis commencing in September 2013, the first month of product sales to Monarch. During the years ended December 31, 2015, 2014 and 2013, the Company amortized $2.0 million, $1.2 million, and $0.5 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 the $15 million Monarch equity interests, JEH assigned $2.4 million of the equity interests to Jonny Jones, the Company's chief executive officer and 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, including Mike McConnell, Robert Brooks and Eric Niccum. The remaining $10 million of Monarch equity interests was distributed to certain of the pre-IPO owners, which included Metalmark Capital, Wells Fargo, the Jones family entities, and certain of the Company's officers and directors, including Jonny Jones, Mike McConnell and Eric Niccum. As of December 31, 2015, equity interests in Monarch of $1.3 million are included in Other assets on the Company's Consolidated Balance Sheet. During the years ended December 31, 2015 and 2014, equity interests of $0.8 million and $0.5 million, respectively, were distributed to management under the incentive plan. The Company recognized expense of $0.5 million, $0.8 million, and $0.3 million during the years ended December 31, 2015, 2014, and 2013, respectively, in connection with the incentive plan.

In September 2014, the Company signed a 10-year oil gathering and transportation agreement with Monarch Oil Pipeline LLC, pursuant to which Monarch Oil Pipeline LLC built, at its expense, a new oil gathering system and connected the gathering system to dedicated Company leases in Texas. At the time the Company entered into the agreement, Metalmark Capital owned the majority of the outstanding equity interests of Monarch Oil Pipeline LLC and/or its parent. The system began service during the fourth quarter of 2015 and provides connectivity to both a regional refinery market as well as the Cushing market hub. The Company did not incur or capitalize any costs associated with the construction of the pipeline. The Company did, however, incur gathering fees of $0.4 million which were paid to Monarch Oil Pipeline LLC associated with the approximately 0.2 MMBoe of oil production transported under the agreement for the year ended December 31, 2015. These costs are recorded as an offset to Oil and gas sales in the Company's Consolidated Statement of Operations. The aforementioned production was recognized as Oil and gas sales on the Company's Consolidated Statement of Operations at the time it was sold to the purchasers, who are unaffiliated third-parties, after passing through the gathering and transportation system. The Company has reserved capacity of up to 12,000 barrels per day on the system with the potential to increase throughput at a future date. The audit committee of the Board reviewed and approved the terms of the agreement with Monarch Oil Pipeline LLC.

In May 2015, the Company received a $0.7 million cash distribution associated with its equity interests in Monarch, which was accounted for following the cost method. The initial cash distribution from Monarch was treated as dividend income and is recorded in Other income (expense).

Purchases of Senior Unsecured Notes

On February 29, 2016, JEH and Jones Energy Finance Corp. purchased a portion of their outstanding 9.25% senior unsecured notes due 2023 ("2023 Notes") from investment funds managed by Magnetar Capital and its affiliates, which investment funds collectively own more than 5% of a class of voting securities of the Company, for approximately $25.4 million. On the same day, JEH and Jones Energy Finance Corp. purchased an additional portion of their outstanding 2023 Notes from investment funds managed by Blackstone Group Management L.L.C. and its affiliates, which investment funds collectively own more than 5% of a class of voting securities of the Company, for approximately $25.4 million.

Procedures for Approval of Related Party Transactions

A "Related Party Transaction" is a transaction, arrangement or relationship in which we or any of our subsidiaries was, is or will be a participant, the amount of which involved exceeds $120,000, and in which any related person had, has or will have a direct or indirect material interest. A "Related Person" means:

- any person who is, or at any time during the applicable period was, one of our executive officers or one of our directors;
- any person who is known by us to be the beneficial owner of more than 5% of our Class A Shares;
- any immediate family member of any of the foregoing persons, which means any child, stepchild, parent, stepparent, spouse, sibling, mother-in- law, father-in-law, son-in-law, daughter-in-law, brother-in-law or sister-in-law of a director, executive officer or a beneficial owner of more than 5% of our Class A Shares, and any person (other than a tenant or employee) sharing the household of such director, executive officer or beneficial owner of more than 5% of our Class A Shares; and
- any firm, corporation or other entity in which any of the foregoing persons is a partner or principal or in a similar position or in which such person has a 10% or greater beneficial ownership interest.

The Board has adopted a written related party transactions policy, which can be accessed on our website at www.jonesenergy.com in the Corporate Governance Documents tab of the Investor Relations section. Pursuant to this policy, our audit committee will review all material facts of all Related Party Transactions and either approve or disapprove entry into the Related Party Transaction, subject to certain limited exceptions. In determining whether to approve or disapprove entry into a Related Party Transaction, our audit committee shall take into account, among other factors, the following: (1) whether the Related Party Transaction is on terms no less favorable than terms generally available to an unaffiliated third-party under the same or similar circumstances and (2) the extent of the Related Person's interest in the transaction. Further, the policy requires that all Related Party Transactions required to be disclosed in our filings with the SEC be so disclosed in accordance with applicable laws, rules and regulations.

PRINCIPAL STOCKHOLDERS

The following table sets forth information with respect to the beneficial ownership of our Class A Shares and Class B Shares as of March 1, 2016 by:

- each person known by us to be a beneficial owner of more than 5% of the stock;
- each of our named executive officers;
- each of our directors; and
- all of our current directors and executive officers as a group.

Beneficial ownership of shares is determined under rules of the SEC and generally includes any shares over which a person exercises sole or shared voting or investment power. Except as indicated by footnote, and subject to community property laws where applicable, we believe based on the information provided to us that the persons and entities named in the table below have sole voting and investment power with respect to all of our Class A Shares shown as beneficially owned by them. Applicable percentage of beneficial ownership is based on 30,550,907 Class A Shares and 31,273,130

Class B Shares outstanding on March 1, 2016. Unless otherwise indicated, the address for each holder listed below is c/o Jones Energy, Inc., 807 Las Cimas Parkway, Suite 350, Austin, Texas 78746.

Name	Number of Class A Shares Beneficially Owned(1)	Percent of Class A Shares Beneficially Owned(2) (%)	Combined Voting Power(3) (%)
Five Percent Stockholders			
Metalmark Capital Partners(4)	18,217,506	37.4%	29.5%
Jones Family Entities(5)	13,294,343	31.4%	21.5%
JVL Advisors, L.L.C.(6)	6,288,817	20.6%	10.2%
Rubric Capital Management(7)	2,527,115	8.3%	4.1%
Blackstone Group Management L.L.C.(8)	2,380,953	7.8%	3.9%
Magnetar Capital Partners(9)	2,260,592	7.4%	3.7%
Vanguard Group Inc.(10)	1,660,769	5.4%	2.7%
Directors and Named Executive Officers			
Jonny Jones(11)	13,294,343	31.4%	21.5%
Mike S. McConnell(12)	1,226,333	3.9%	2.0%
Eric Niccum(13)	251,424	*	*
Howard I. Hoffen(14)	18,229,823	37.4%	29.5%
Gregory D. Myers(14)	18,229,823	37.4%	29.5%
Alan D. Bell(15)	25,607	*	*
Halbert S. Washburn(15)	25,607	*	*
Robb L. Voyles(15)	18,962	*	*
Directors and current executive officers as a group (ten total)	**30,317,402**	**50.1%**	**49.0%**

* Less than one percent

(1) Includes Class B Shares owned by certain of these individuals and entities that, subject to the terms of an exchange agreement (the "Exchange Agreement"), are, together with an equivalent number of JEH LLC units, exchangeable at any time and from time to time for Class A Shares on a one-for-one basis, subject to equitable adjustments for stock splits, stock dividends and reclassifications. The table assumes all such Class B shares are fully vested.

(2) The Class A Shares to be issued upon the exchange of Class B Shares that are currently exchangeable pursuant to the terms of the Exchange Agreement are deemed to be outstanding and beneficially owned by the person holding the Class B Shares for the purpose of computing the percentage of beneficial ownership of Class A Shares for that person and any group of which that person is a member, but are not deemed outstanding for the purpose of computing the percentage of beneficial ownership for any other person. As such, in calculating the percentage of Class A Shares beneficially owned by each person, we have assumed that only such person exchanged Class B Shares for Class A Shares and that no other person made a similar exchange.

(3) Represents percentage of voting power of the Class A Shares and Class B Shares of Jones Energy voting together as a single class.

(4) Includes Class A Shares and Class B Shares beneficially owned by Metalmark Capital II LLC indirectly through each of MCP II (Cayman) AIF Jones Intermediate LLC, MCP II Jones Intermediate LLC, MCP II (TE) AIF Jones Intermediate LLC, MCP II Co-Investment Jones Intermediate LLC, MCP (C) II Jones Intermediate LLC and MCP II Executive Fund Jones Intermediate LLC (collectively, "Metalmark Capital Partners"). Metalmark Capital Partners' principal address is 1177 Avenue of the Americas, 40th Floor; New York, NY 10036; Attention: Gregory D. Myers.

(5) Of these shares, 11,760,344 are held by various entities of which Jones Energy Management, LLC or JET 3 GP, LLC is the general partner. Jonny Jones has voting power over all such shares in his capacity as Manager of Jones Energy Management, LLC and Managing Member of JET 3 GP, LLC. Jonny Jones and Jon Rex Jones each indirectly own 50% of Jones Energy Management, LLC. Jonny Jones indirectly owns 100% of JET 3 GP, LLC. Family members or other current or former officers or employees of Jones Energy have direct or indirect ownership interests in the Jones Family Entities and have the right to cause their pro rata portion of the Class B Shares held by the Jones Family Entities to be exchanged for Class A Shares and distributed to them. Jonny Jones disclaims beneficial ownership of the Class B Shares held by the Jones Family Entities except to the extent of his pecuniary interest therein. If all Class B Shares held by the Jones Family Entities were distributed to the individuals or entities that hold direct or indirect ownership interests in them, Jonny Jones would beneficially own 5,712,881 Class B Shares (18.3% of the Class B Shares) and 200,566 Class A Shares representing a 9.6% combined voting power. 1,659,039 Class B Shares would be deemed to be beneficially owned by both Jonny Jones and Jon Rex Jones. Indirect ownership of 1,114,851 of these shares have been pledged from one Jones Family Entity to another for estate planning purposes. Each of the Jones Family Entities party to those pledges is ultimately owned by Jonny Jones. Of the remaining shares, 1,333,433 shares reported in this column are held by a Jones Family Entity in which Jonny Jones has a pecuniary interest but no voting or dispositive power. Each of the Jones Family Entities disclaims beneficial ownership of the shares reported herein except to the extent of their pecuniary interests therein. The address for the Jones Family Entities is JRJ Management Company, LLC, 807 Las Cimas Parkway, Suite 245, Austin, TX 78746.

(6) Based on information obtained from the Form 13F filed by JVL Advisors, L.L.C. ("JVL") with the SEC on February 12, 2016. According to this report, JVL's business address is 10000 Memorial Drive, Suite 550, Houston, Texas 77024.

(7) Based on information obtained from the Schedule 13G filed jointly by Point72 Asset Management, L.P., Point72 Capital Advisors, Inc., Cubist Systematic Strategies, LLC, Rubric Capital Management, LLC, and Steven A. Cohen (collectively, "Rubric") with the SEC on February 16, 2016. According to this report, Rubric's primary business address is 72 Cummings Point Road, Stamford, CT 06902 with the exception of Cubist Systematic Strategies, LLC whose address is 330 Madison Avenue New York, NY 10173.

(8) Based on information obtained from the Schedule 13G filed jointly by Blackstone Group Management, L.L.C., The Blackstone Group L.P., Blackstone Holdings I/II GP Inc., Blackstone Holdings I L.P., Blackstone Holdings II L.P., GSO Advisor Holdings L.L.C., GSO Capital Partners LP, GSO Special Situations Fund LP, GSO Special Situations Overseas Fund Ltd., GSO Special Situations Overseas Master Fund Ltd., GSO Holdings I L.L.C., GSO Energy Market Opportunities Associates LLC, GSO Energy Market Opportunities Fund LP, Stephen A. Schwarzman, Bennett J. Goodman, J. Albert Smith III and Douglas I. Ostrover (collectively, "Blackstone") with the SEC on March 5, 2015. According to this report, Blackstone's business address is c/o GSO Capital Partners LP, 345 Park Avenue, New York, NY 10154. Blackstone has shared voting power with respect to 2,380,953 of the shares and shared dispositive power with respect to 2,380,953 of the shares.

(9) Based on information obtained from the Schedule 13G filed jointly by MTP Energy Master Fund LTD, MTP Energy Management LLC, Magnetar Financial LLC, Magnetar Capital Partners LP, Supernova Management LLC, and Alec N. Litowitz (collectively, "Magnetar") with

the SEC on February 16, 2016. According to this report Magnetar's business address is 1603 Orrington Avenue, 13th Floor, Evanston, IL 60201.

(10) Based on information obtained from the Schedule 13G filed jointly by The Vanguard Group, Inc., Vanguard Fiduciary Trust Company, Vanguard Investments Australia, Ltd., and F. William McNabb III, (collectively, "Vanguard") with the SEC on February 10, 2016. According to this report, Vanguard's business address is 100 Vanguard Boulevard, Malvern, PA, 19355.

(11) Of these shares, 11,760,344 are held by various entities of which Jones Energy Management, LLC or JET 3 GP, LLC is the general partner. Jonny Jones has voting power over all such shares in his capacity as Manager of Jones Energy Management, LLC and Managing Member of JET 3 GP, LLC. Jonny Jones and Jon Rex Jones each indirectly own 50% of Jones Energy Management, LLC. Jonny Jones indirectly owns 100% of JET 3 GP, LLC. Family members or other current or former officers or employees of Jones Energy have direct or indirect ownership interests in the Jones Family Entities and have the right to cause their pro rata portion of the Class B Shares held by the Jones Family Entities to be exchanged for Class A Shares and distributed to them. Jonny Jones disclaims beneficial ownership of the Class B Shares held by the Jones Family Entities except to the extent of his pecuniary interest therein. If all Class B Shares held by the Jones Family Entities were distributed to the individuals or entities that hold direct or indirect ownership interests in them, Jonny Jones would beneficially own 5,712,881 Class B Shares (18.3% of the Class B Shares) and 200,566 Class A Shares representing a 9.6% combined voting power. 1,659,039 Class B Shares would be deemed to be beneficially owned by both Jonny Jones and Jon Rex Jones. Indirect ownership of 1,114,851 of these shares have been pledged from one Jones Family Entity to another for estate planning purposes. Each of the Jones Family Entities party to those pledges is ultimately owned by Jonny Jones. Of the remaining shares, 1,333,433 shares reported in this column are held by a Jones Family Entity in which Jonny Jones has a pecuniary interest but no voting or dispositive power. Each of the Jones Family Entities disclaims beneficial ownership of the shares reported herein except to the extent of their pecuniary interests therein. The address for the Jones Family Entities is JRJ Management Company, LLC, 807 Las Cimas Parkway, Suite 245, Austin, TX 78746.

(12) Of these shares, 1,226,095 are currently held by the Jones Family Entities, but Mr. McConnell has the right to cause them to be exchanged for Class A Shares and distributed to himself or entities that he controls. The remaining shares are Class A shares held by an entity in which Mr. McConnell has control.

(13) Of these shares, 248,262 are currently held by the Jones Family Entities, but Mr. Niccum has the right to cause them to be exchanged for Class A Shares and distributed to himself or entities that he controls. The remaining shares are Class A shares held by Mr. Niccum.

(14) Messrs. Hoffen and Myers are each managing directors of Metalmark and may be deemed to share beneficial ownership of any shares held by Metalmark. Each of Messrs. Hoffen and Myers disclaim beneficial ownership of these shares as a result of his employment arrangements with Metalmark, except to the extent that his pecuniary interest therein is ultimately realized. The address of each of Messrs. Hoffen and Myers is c/o Metalmark Capital Partners; 1177 Avenue of the Americas, 40th Floor; New York, NY 10036. In addition, Messrs. Hoffen and Myers have each been granted 25,607 restricted Class A Shares as compensation for their services as independent directors on our Board, a portion of which has vested as of the date noted above.

(15) Messrs. Bell, Washburn and Voyles were each granted these restricted Class A Shares as compensation for their services as independent directors on our Board, a portion of which has vested as of the date noted above.

To our knowledge, except as noted above, no person or entity is the beneficial owner of more than 5% of the voting power of Jones Energy's stock.

SECTION 16(a) BENEFICIAL OWNERSHIP REPORTING COMPLIANCE

Section 16(a) of the Exchange Act, requires our executive officers, directors, and greater than 10 percent stockholders to file with the SEC certain reports of ownership and changes in ownership of our Common Stock. Based on a review of the copies of such forms received and written representations from certain reporting persons, we believe that all Section 16(a) reports applicable to our executive officers, directors and greater than 10 percent stockholders were timely filed in 2015, except for a Form 3 and any applicable Form 4s related to Class A Shares owned by JVL Advisors, L.L.C. and a Form 4 related to the Secondary Offering, which was filed with the SEC on February 12, 2016

PROPOSAL TWO:
RATIFICATION OF INDEPENDENT PUBLIC ACCOUNTING FIRM

The Audit Committee of the Board has determined to engage PricewaterhouseCoopers LLP as our independent registered public accounting firm for the fiscal year ending December 31, 2016. PricewaterhouseCoopers LLP also served as our independent registered public accounting firm for fiscal years ended December 31, 2015 and December 31, 2014.

The Board requests stockholder approval of the following resolution adopted by the Audit Committee and the Board.

> "**RESOLVED**, that PricewaterhouseCoopers LLP is hereby selected as the independent public accounting firm of the Corporation for the year ending December 31, 2016, and such selection be hereby approved and ratified as of the date hereof."

THE BOARD RECOMMENDS THAT THE STOCKHOLDERS VOTE "FOR" THE PROPOSAL TO RATIFY THE APPOINTMENT OF PRICEWATERHOUSECOOPERS LLP AS JONES ENERGY'S INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM FOR 2016.

The affirmative vote of a majority of the voting power of the shares present in person or by proxy and entitled to vote is required for adoption of this proposal. If the appointment is not approved, the adverse vote will be considered as an indication to the Board that it should select another independent registered public accounting firm for the following year. Because of the difficulty and expense of making any substitution of public accountants so long after the beginning of the current year, it is contemplated that the appointment for 2016 will be permitted to stand unless the Audit Committee finds other good reason for making a change.

Representatives of PricewaterhouseCoopers LLP are expected to be present at the Annual Meeting to respond to appropriate questions raised at the Annual Meeting or submitted to them in writing prior to the Annual Meeting. The representatives may also make a statement if they desire to do so.

PRICEWATERHOUSECOOPERS LLP FEES FOR FISCAL YEARS 2015 AND 2014

	2015	2014
Audit Fees(1)	$1,506,100	$847,000
Audit-Related Fees(2)	—	—
Tax Fees(3)	—	—
All Other Fees(4)	10,007	112,000
Total:	$1,516,107	$959,000

(1) "Audit Fees" represents fees for professional services provided in connection with the audits of the Jones Energy's annual financial statements included in its 2015 Annual Reports on Form 10-K and reviews of the 2015 interim financial statements. In addition, "Audit Fees" includes work associated with comfort letters issued in conjunction with public filings by Jones Energy.

(2) "Audit-Related Fees" represents fees for professional services rendered in connection with audit work unrelated to the primary financial statements of Jones Energy and its subsidiaries.

(3) "Tax Fees" represents fees associated with tax services rendered for income tax planning and compliance, and sales, use and excise tax matters.

(4) "All Other Fees" represents other consulting services. The Audit Committee has concluded that these services are compatible with maintaining PricewaterhouseCoopers LLP's independence.

The charter of the Audit Committee and its pre-approval policy require that the Audit Committee pre-approve all auditing services, internal control-related services and permitted non-audit services (including the fees and terms thereof) to be performed for the Company by PricewaterhouseCoopers LLP, subject to such exceptions for non-audit services as permitted by applicable laws and regulations. The Committee may, when it deems appropriate, form and delegate this authority to a subcommittee consisting of one or more Committee members for purposes of this review and pre-approval. For the year ended December 31, 2015, the Audit Committee pre-approved 100% of the services described above opposite the captions "Audit Fees," "Audit-Related Fees," "Tax Fees" and "All Other Fees."

PROPOSAL THREE: APPROVAL OF THE AMENDED AND RESTATED JONES ENERGY, INC. 2013 OMNIBUS INCENTIVE PLAN

On March 25, 2016, the Board adopted, pursuant to a recommendation from the Compensation Committee and subject to stockholder approval, an amended and restated LTIP, which includes an increase in the number of Class A Shares authorized for issuance under the LTIP. Shortly before our IPO, the Board adopted, and our stockholders approved, the current LTIP, effective upon consummation of the IPO, which authorized the issuance of up to 3,850,000 Class A Shares, of which 2,523,853 shares remained available for future issuance under the LTIP as of March 1, 2016.

We are requesting approval of 3,500,000 additional shares to be added to the LTIP, which additional shares will be available under our plan if the LTIP is approved.

If approved, the amended and restated LTIP would authorize an additional 3,500,000 Class A Shares for issuance under our LTIP such that a total of 6,023,853 Class A Shares would be available for issuance following stockholder approval (the 6,023,853 shares represent 2,523,853 shares remaining as of March 1, 2016, plus 3,500,000 new shares). The amended and restated LTIP also increases the individual annual award limits for employees, revises the share counting provisions, and modifies the qualified performance awards. If this proposal is approved, the LTIP will be amended and restated and the number of shares authorized under the LTIP will be increased as described above effective as of the date of the Annual Meeting. All shares of Common Stock available under the LTIP are available for incentive stock options under Section 422 of the Internal Revenue Code of 1986, as amended (the "Code").

Stockholder approval of the LTIP will also constitute approval for purposes of satisfying the stockholder approval requirements (i) under Section 162(m) of the Code, and the rules and regulations thereunder, of the plan and the "material terms of the performance goals" under the LTIP so that the Compensation Committee has the discretion to grant equity- and cash-based awards in the future under the LTIP that meet the requirements of "performance-based compensation" under Section 162(m) and (ii) under Section 422 of the Code so that the Compensation Committee may grant incentive stock options.

The Board recommends that stockholders approve the LTIP. The Board believes it is in the best interest of the Company and its stockholders for the stockholders to approve the LTIP. The affirmative vote of a majority of the shares present in person or by proxy and entitled to vote at the meeting is required to approve the LTIP. Although this discussion summarizes the principal terms and conditions of the LTIP (as amended and restated), it does not purport to be complete and is qualified in its entirety by reference to the amended and restated LTIP which is attached as Appendix A to this proxy statement.

Background and Purpose

Our LTIP is designed to attract and retain employees, consultants and non-employee directors and to encourage the sense of proprietorship of such individuals and to stimulate the active interest of such persons in the development of our success. To accomplish this goal, equity, equity-based and cash awards may be made under the LTIP to employees and consultants of the Company and our affiliates and to our directors. The Compensation Committee and the Board strongly believe that granting equity awards motivates employees to think and act like owners, rewarding them when value is created for our stockholders. Our employees, consultants and non-employee directors are some of our most valuable assets. As of March 1, 2016, the Company had 48 LTIP-eligible employees, no LTIP-eligible consultants and five LTIP-eligible directors. The Company estimates that 100% of the LTIP-eligible employees participate in the LTIP. Because the LTIP provides for broad discretion in selecting participants and in making awards, however, the total number of persons who will participate going forward and the respective benefits to be awarded to them cannot be determined at this time.

The LTIP provides for the issuance of stock options (incentive stock options and nonstatutory stock options), restricted stock, performance awards, restricted stock units, bonus stock awards, stock appreciation rights, dividend equivalents and cash awards. With respect to equity awards made under the LTIP, no employee may be granted during a single calendar year (i) stock options or stock appreciation rights that are exercisable for more than 2.5000,000 Class A Shares; (ii) performance-based awards settled in our Class A Shares or other stock awards covering or relating to more than 2,500,000 shares of our Class A Shares or (iii) cash awards or performance-based awards settled solely in cash having a grant date value in excess of $5,000,000. No non-employee director may be granted, during a single calendar year, awards having a value determined on the grant date in excess of $500,000.

Best Practice Features of the LTIP

The Board believes that the LTIP will promote the interests of our stockholders, reflects our commitment to effective incentive compensation and is consistent with principles of good corporate governance, including the following features:

- *No Repricing of Options or Stock Appreciation Rights.* The LTIP prohibits repricing, replacement and regranting of stock options or stock appreciation rights at lower prices unless approved by our stockholders.
- *No Discounted Options or Stock Appreciation Rights.* Stock options and stock appreciation rights may not be granted with an exercise price below the fair market value of our Class A Shares on the date of grant.
- *No Dividends on Options or Stock Appreciation Rights.* Dividends and dividend equivalents may not be paid or accrued on stock options or stock appreciation rights.
- *Limited terms for Options and Stock Appreciation Rights.* Stock options and stock appreciation rights granted under the LTIP are limited to 10-year terms.
- *Dividend Equivalents.* Only an award of restricted stock units may include dividend equivalents, which may not be paid out prior to the time the underlying award vests.
- *Annual Limitation on Director Awards.* The aggregate grant value of awards (as determined on the grant date) to any individual non-employee director may not exceed $500,000 in any calendar year.
- *Awards may be subject to future clawback or recoupment.* All awards granted under the LTIP will be subject to any clawback policy adopted by us.
- *No Transferability.* Awards generally may not be transferred, except by will or the laws of descent and distribution or pursuant to a domestic relations order, unless approved by the Compensation Committee.
- *No "Evergreen" Provision.* Shares authorized for issuance under the LTIP will not be replenished automatically. Any additional shares to be issued over and above the amount for which we are seeking authorization must be approved by our stockholders.
- *No Tax Gross-ups.* Participants do not receive tax gross-ups under the LTIP.

Section 162(m) of the Code

Following our IPO, we were eligible for a post-initial public offering transition rule under which amounts paid under our LTIP were exempt from the deduction limitations of Section 162(m) of the Code. In order to preserve our ability to grant fully tax-deductible performance-based awards following the end of this transition period, we are seeking stockholder approval of the material terms of the performance goals under the LTIP for purposes of compliance with Section 162(m) of the Code. The LTIP has been structured in a manner such that awards granted under it can satisfy the requirements for "performance-based compensation" within the meaning of Section 162(m) of the Code. However, there can be no guarantee that amounts payable under the LTIP will be treated as qualified "performance-based compensation" under Section 162(m) of the Code. In general, since we are currently a smaller reporting company for purposes of the Exchange Act, under Section 162(m) of the Code, the federal income tax deductibility of compensation paid to our chief executive officer or any of our two other most highly compensated executive officers may be limited to the extent such compensation exceeds $1,000,000 in any taxable year. However, compensation that qualifies as "performance-based compensation" is excluded from this $1,000,000 deduction limit and therefore remains fully tax deductible by us. The requirements of Section 162(m) of the Code for performance-based compensation include, but are not limited to, stockholder approval of the material terms of the performance goals under which compensation is paid and the reapproval of such performance goals no less frequently than every five years.

For purposes of Section 162(m) of the Code, the material terms of the performance goals for performance-based compensation that may be awarded under the LTIP are: (i) the class of eligible persons who may receive compensation under the LTIP; (ii) the business criteria on which the performance goals are based; and (iii) the maximum amount of compensation that may be paid to a participant under the LTIP. The material terms of the performance goals under the LTIP are described below.

In addition, while approval of the performance goals is required for compensation to qualify as "performance-based compensation" under Section 162(m) of the Code, it does not mean that all awards or other compensation under the LTIP will qualify, or be intended to qualify, as performance-based compensation or otherwise be deductible.

Administration

The LTIP is administered by the Compensation Committee. The plan administrator selects the participants and determines the type or types of awards and the number of shares to be optioned or granted to each participant under the LTIP.

The plan administrator supervises the LTIP's administration and enforcement according to its terms and provisions and has all powers necessary to accomplish these purposes, including, for example, the power to: (i) engage or authorize the engagement of third-party administrators to carry out administrative functions under the LTIP; (ii) construe or interpret the LTIP with full and final authority; (iii) determine questions of eligibility; (iv) make determinations related to LTIP benefits; (v) delegate to the Board or any other committee of the Board its authority to grant awards to certain employees; and (vi) from time to time, adopt rules and regulations in order to carry out the terms of the LTIP. Members of the Board, the plan administrator and other officers who assume duties under the LTIP are not held liable for their actions in connection with administration of the LTIP except for willful misconduct or as expressly provided by law.

The plan administrator may terminate or amend the LTIP at any time with respect to any of our Class A Shares for which a grant has not yet been made. The plan administrator also has the right to alter or amend the LTIP or any part of the LTIP from time to time, including increasing the number of our Class A Shares that may be granted, subject to stockholder approval. However, no change in any outstanding grant may be made that would materially reduce the benefits of a participant without the consent of such participant. Repricing of options and stock appreciation rights is prohibited under the LTIP without the approval of our stockholders; options and stock appreciation rights may not be cancelled in exchange for cash or other awards. In the event of corporate recapitalizations, subdivisions, consolidations, or other corporate events, the plan administrator has the authority to adjust outstanding awards as well as the total number of shares available for grant under the plan in accordance with the terms of the LTIP. No awards may be granted under the LTIP on or after July 29, 2023, which is the ten year anniversary of the effective date.

Participation and Eligibility

Our employees, consultants, employees of our subsidiaries, consultants of our subsidiaries and our non-employee directors are eligible for awards under the LTIP. The plan administrator selects the participants in the LTIP. Any participant may receive more than one award under the LTIP. A subsidiary is defined in the LTIP as: "(1) in the case of a corporation, any corporation of which the Company directly or indirectly owns shares representing 50% or more of the combined voting power of the shares of all classes or series of capital stock of such corporation which have the right to vote generally on matters submitted to a vote of the stockholders of such corporation, and (2) in the case of a partnership or other business entity not organized as a corporation, any such business entity of which the Company directly or indirectly owns 50% or more of the voting, capital or profits interests (whether in the form of partnership interests, membership interests or otherwise)."

Number of Authorized Shares

As of March 1, 2016, 2,523,853 Class A Shares were available for granting of new awards. The closing price of our Class A Shares was $1.61 per share on March 1, 2016. The Board has approved the amended and restated LTIP that, subject to stockholder approval, would increase by 3,500,000 the number of Class A Shares that may be issued under the LTIP to eligible employees, consultants and directors . If stockholder approval is not obtained, the LTIP will continue as in effect immediately prior to its amendment and restatement. All Class A Shares reserved under the LTIP may be issued pursuant to incentive stock options, within the meaning of Section 422 of the Code ("ISOs"). The Class A Shares delivered to settle awards under the LTIP may be authorized and unissued shares or treasury shares, including shares repurchased for purposes of the LTIP. If any shares subject to any award are forfeited or payment is made in a form other than shares or the award otherwise terminates without payment being made, the shares subject to such awards generally may again be available for issuance under the LTIP. Shares covered by the unexercised portion of an award that terminates, expires or is canceled or settled in any form other than shares and shares forfeited will again become available for issuance under the LTIP.

Limits on Awards

With respect to equity awards made under the LTIP, no employee may be granted during a single calendar year (i) stock options or stock appreciation rights that are exercisable for more than 2,500,000 Class A Shares; (ii) performance-based awards settled in our Class A Shares or other stock awards covering or relating to more than 2,500,000 Class A Shares or (iii) cash awards or performance-based awards settled solely in cash having a grant date value in excess of $5,000,000. No non-employee director may be granted, during a single calendar year, awards having a value determined on the grant date in excess of $500,000.

Summary of Awards under the LTIP

The LTIP provides for the issuance of stock options (incentive stock options and nonstatutory stock options), restricted stock, performance awards, restricted stock units, bonus stock awards, stock appreciation rights, dividend equivalents, and cash awards.

Restricted Stock

A restricted stock grant is an award of Class A Shares that vests over a period of time and that during such time is subject to forfeiture. The plan administrator may determine to make grants of restricted stock under the plan to participants containing such terms as the plan administrator shall determine. The plan administrator determines the period over which restricted stock granted to participants will vest. The plan administrator, in its discretion, may base its determination upon the achievement of specified performance objectives. Dividends made on restricted stock will not be paid with respect to unvested restricted stock, including restricted stock that is subject to the achievement of performance goals.

Restricted stock under the LTIP is intended to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of our Class A Shares. Therefore, plan participants do not pay any consideration for our Class A Shares they receive, and we receive no remuneration for the restricted stock.

Stock Options

A stock option is a right to purchase stock at a specified price during specified time periods. The LTIP permits the grant of options covering our Class A Shares. The plan administrator may make grants under the plan to participants containing such terms as the plan administrator shall determine. Stock options have an exercise price that may not be less than the fair market value of our Class A Shares on the date of grant. Stock options granted under the LTIP can be either ISOs, which have certain tax advantages for recipients, or non-qualified stock options. ISOs may only be granted to employees. Stock options granted become exercisable over a period determined by the plan administrator. No stock option has a term that exceeds ten years. The availability of stock options is intended to furnish additional compensation to plan participants and to align their economic interests with those of common stockholders.

Performance Awards

A performance award is a right to receive all or part of an award granted under the LTIP based upon performance criteria specified by the plan administrator. The plan administrator determines the period over which certain specified company or individual goals or objectives must be met. The performance award may be paid in cash, Class A Shares or other awards or property, in the discretion of the plan administrator.

Performance awards may be structured as "qualified performance-based compensation" under Section 162(m) of the Code, which we refer to as Qualified Awards. For Qualified Awards, performance goals must be established by the Compensation Committee (1) no later than 90 days after the commencement of service to which the performance goal relates and (2) prior to the completion of 25% of the performance period. A performance goal may be based upon one or more business criteria that apply to the participant or the performance of one or more of our business units or the company as a whole, and must be based on one or more of the criteria set forth under the LTIP.

Performance Goals

Performance awards granted to employees under the LTIP that are intended to qualify as qualified performance-based compensation under Section 162(m) of the Code will be subject to one or more of the following performance goals: (1) earnings per share; (2) production; (3) increase in cash flow; (4) increase in cash flow from operations; (5) increase in cash flow return; (6) return on net assets; (7) return on assets; (8) return on investment; (9) return on capital; (10) return on equity; (11) economic value added; (12) operating margin; (13) increase in production; (14) net income; (15) net income per share; (16) pretax earnings; (17) pretax earnings before interest, depreciation and amortization; (18) pretax earnings before interest, depreciation, amortization and exploration; (19) pretax operating earnings after interest expense and before incentives, service fees, and infrequent or unusual items; (20) total stockholder return; (21) debt reduction; (22) finding and development costs; (23) operating income; (24) internal rate of return; (25) safety; (26) operating expenses; (27) general and administrative expenses; (28) capital efficiency; (29) reserve replacement cost; and (30) any of the above goals determined on an absolute or relative basis or as compared to the performance of a published or special index deemed applicable by the Committee including, but not limited to, the Standard & Poor's 500 Stock Index, Russell 2000 or a group of comparable companies. One or more of such goals may apply to the employee, one or more business units, divisions or sectors of the Company, or the Company as a whole, and if so desired by the Compensation Committee, by comparison with a peer group of companies.

A performance goal need not be based upon an increase or positive result under a particular business criterion and could include, for example, maintaining the status quo or limiting economic losses. The Compensation Committee will also have discretion to reduce (but not to increase) the value of a Qualified Award.

Restricted Stock Units

A restricted stock unit is a notional share of our Class A Shares that entitles the grantee to receive a share of our Class A Shares upon the vesting of the restricted stock unit or, in the discretion of the plan administrator, cash equivalent to the value of a share of our Class A Shares. The plan administrator may determine to make grants of restricted stock units under the plan to participants containing such terms as the plan administrator shall determine. The plan administrator determines the period over which restricted stock units granted to participants will vest.

The plan administrator, in its discretion, may grant tandem dividend equivalent rights with respect to restricted stock units that entitle the holder to receive cash equal to any cash dividends made on Class A Shares while the restricted stock units are outstanding. Dividend equivalents on restricted stock units are subject to achievement of any performance goals that apply to the restricted stock units.

We intend the issuance of any shares of our Class A Shares upon vesting of the restricted stock units under the plan to serve as a means of incentive compensation for performance and not primarily as an opportunity to participate in the equity appreciation of our Class A Shares. Therefore, plan participants do not pay any consideration for the Class A Shares they receive, and thus we do not receive remuneration for the shares.

Bonus Stock

The plan administrator, in its discretion, may also grant to participants Class A Shares that are not subject to forfeiture. The plan administrator can grant bonus stock without requiring that the recipient pay any remuneration for the shares.

Stock Appreciation Rights

The LTIP permits the grant of stock appreciation rights. A stock appreciation right is an award that, upon exercise, entitles participants to receive the excess of the fair market value of our Class A Shares on the exercise date over the grant price established for the stock appreciation right on the date of grant. Such excess is paid in cash or shares of our Class A Shares. The maximum term of a stock appreciation right is ten years. The plan administrator may determine to make grants of stock appreciation rights under the plan to participants containing such terms as the plan administrator shall determine. Stock appreciation rights have a grant price that may not be less than the fair market value of our Class A Shares on the date of grant. In general, stock appreciation rights granted will become exercisable over a period determined by the plan administrator.

The availability of stock appreciation rights is intended to furnish additional compensation to plan participants and to align their economic interests with those of common stockholders. Plan participants do not pay any consideration for the Class A Shares they receive, and thus we receive no remuneration for the shares.

Other Share-Based Awards

The plan administrator, in its discretion, may also grant to participants an award denominated or payable in, referenced to, or otherwise based on or related to the value of our Class A Shares.

Cash Awards

The plan administrator, in its discretion, may also grant to participants an award denominated in cash.

Termination of Employment and Non-Competition Agreements

The treatment of an award under the LTIP upon a termination of employment or service to us will be specified in the applicable award agreement. Additionally, each participant to whom an award is granted under the LTIP may be required to agree in writing as a condition of the granting of such award not to engage in conduct in competition with us or our affiliates after the termination of such participant's employment or service with us.

Assignments of Interests Prohibited

Unless otherwise determined by the plan administrator and provided in the applicable award agreement, no award may be assigned or otherwise transferred except by will or the laws of descent and distribution or pursuant to a domestic relations order in a form acceptable to the plan administrator. Any attempted assignment of an award in violation of the LTIP will be null and void.

Adjustments

In the event of any other recapitalization or capital reorganization of the Company, any consolidation or merger of the Company with another corporation or entity, the adoption by the Company of any plan of exchange affecting the Class A Shares or any distribution to holders of Class A Shares of securities or property (other than normal cash dividends or dividends payable in Class A Shares), the Compensation Committee shall make appropriate adjustments to (i) the number and kind of Class A Shares covered by awards denominated in Class A Shares, (ii) the exercise price in respect of such awards, (iii) the appropriate fair market value for such awards, and (iv) the annual award limits to reflect such transaction; provided that such adjustments shall only be such as are necessary to maintain the proportionate interest of the holders of the awards and preserve, without increasing, the value of such awards. Additionally, in the event of any subdivision or consolidation of outstanding Class A Shares, declaration of a dividend payable in Class A Shares or other stock split, then in addition to the adjustments listed above, the number of Class A Shares reserved under the LTIP may also be adjusted. No adjustment shall be made that would result in the LTIP or benefits payable thereunder to fail to comply with or be exempt from Section 409A of the Code.

Change in Control

The treatment of awards on the occurrence of a change in control (as defined in the LTIP) will be determined in the sole discretion of the plan administrator and will be described in the applicable award agreement. Such treatment may include the acceleration of vesting or the lapse of restrictions on the occurrence of a change in control or upon termination of employment following a change in control. For further information on the treatment of Awards on the occurrence of a change in control, please see the LTIP.

Restrictions

No payment or delivery of Class A Shares may be made unless we are satisfied that payment or delivery will comply with applicable laws and regulations. Certificates evidencing Class A Shares delivered under the LTIP may be subject to stop transfer orders and other restrictions that the plan administrator deems advisable. The plan administrator may cause a legend or legends to be placed upon the certificates (if any) to make appropriate reference to these restrictions.

Clawback

Any award which is subject to recovery under any law, government regulation, or stock exchange listing requirement will be subject to the deductions and clawback that are required to be made pursuant to such law, government regulation, stock exchange listing requirement or any policy adopted by us.

Tax Withholding

We have the right to deduct taxes at the applicable rate from any award payment and withhold, at the time of delivery or vesting of an award, an appropriate amount of cash or number of Class A Shares for the payment of taxes. The plan administrator may also permit withholding to be satisfied by the transfer of Class A Shares previously owned by the holder of the award.

Unfunded Plan

The LTIP is unfunded. Bookkeeping accounts that may be established for purposes of the LTIP are used merely as a bookkeeping convenience. We are not required to segregate any assets for purposes of the LTIP, and neither us, our Board nor the plan administrator is deemed to be a trustee of any benefit granted under the LTIP. Our obligations under the LTIP are based solely on any contractual obligations that may be created by the LTIP and the applicable award agreement, and no such obligation will be deemed to be secured by any pledge or other encumbrance on our property. None of us, our Board or the plan administrator is required to give any security or bond for the performance of any obligation that may be created by the LTIP.

U.S. Income Tax Considerations

The following is a brief summary of the federal income tax aspects of awards that may be made under the LTIP based on existing U.S. federal income tax laws. This summary is general in nature and does not address issues related to the tax circumstances of any particular participant. This summary is not complete and does not attempt to describe any state, local or non-U.S. tax consequences.

Stock Options

The grant of a stock option is not a taxable event. In general, a participant who receives an option that does not qualify as an "incentive stock option" under Section 422 of the Code will realize ordinary income at the time the option is exercised equal to the difference between the then value of the shares acquired by the exercise of the option over the option exercise price paid for the shares, and we will be entitled to a corresponding deduction, subject to the potentially applicable deduction limitations under Section 162(m) of the Code. The participant's tax basis for the shares will be equal to the value of the shares on the date ordinary income is realized and the participant's tax holding period for the shares will begin on that date. Gain or loss on a subsequent sale of the shares will be long- or short-term capital gain or loss, depending on whether the sale occurs more than one year after the participant's holding period begins.

If a participant receives a stock option that qualifies as an "incentive stock option" under Section 422 of the Code, the participant will not realize income at the time the option is exercised (although the difference between the value of the shares and the exercise price will be taken into account as income for alternative income tax purposes), but will realize taxable income when the option shares are subsequently sold. If the participant sells the option shares more than two years after the date the option is granted and more than one year after the date the option is exercised, any gain or loss realized on the sale will be long-term capital gain or loss, and we will not be entitled to a deduction. If the participant sells the option shares before the end of either of those periods, any gain realized on the sale will be taxable as ordinary income to the extent of the difference between the value of the shares on the date the option was exercised and the exercise price paid for the shares, and any remaining gain will be capital gain. Any such capital gain will be long- or short-term capital gain or loss, depending on whether the sale occurs more than one year after the date the option was exercised. In general, we will be entitled to a deduction only if and to the extent ordinary income is realized by the participant upon the sale of the option shares, subject to the potentially applicable deduction limitations under Section 162(m) of the Code.

Stock Appreciation Rights

The grant of a stock appreciation right will not result in any immediate tax consequence to us or to the participant. Generally, the participant will realize ordinary income upon the exercise of a stock appreciation right, equal to the value of the shares or the cash payment issued or made in settlement of the award, and we will be entitled to a corresponding deduction, subject to the potentially applicable deduction limitations under Section 162(m) of the Code.

Restricted Stock, Restricted Stock Units and Bonus Stock Awards

In general, a participant who receives restricted stock, restricted stock units or bonus stock awards under the LTIP will realize ordinary income at the time the award becomes vested or the participant receives vested shares in settlement of the award in an amount equal to the then fair market value of the shares, and we will be entitled to a corresponding deduction (subject to the potentially applicable deduction limitations under Section 162(m) of the Code). In cases where the participant receives restricted stock and makes an election under Section 83(b) of the Code, the participant would realize ordinary income at the time the restricted stock is issued in an amount equal to the then fair market value of the shares, and we will be entitled to a corresponding deduction (subject to the potentially applicable deduction limitations under Section 162(m) of the Code). The participant's tax basis in the shares will generally be equal to the value of the shares on the date that ordinary income is realized, and the participant's tax holding period for the shares will generally begin on that date. Gain or loss on a subsequent sale of the shares will be long- or short-term capital gain or loss, depending on whether the sale occurs more than one year after the participant's holding period begins.

Tax Deductibility Limitation

Section 162(m) of the Code provides that certain compensation received in any year by a "covered employee" in excess of $1,000,000 is non-deductible by us for federal income tax purposes. Section 162(m) provides an exception, however, for "performance-based compensation." The LTIP permits the Compensation Committee to structure grants and awards made under the LTIP to "covered employees" as performance-based compensation that is exempt from the limitation of Section 162(m) of the Code. However, the Committee may award compensation that is or may become non-deductible, and expects to consider whether it believes such grants are in our best interest, balancing tax efficiency with long-term strategic objectives.

Section 409A

Section 409A of the Code generally provides that any deferred compensation arrangement must satisfy specific requirements, both in operation and in form, regarding (1) the timing of payment, (2) the election of deferrals, and (3) restrictions on the acceleration of payment. Failure to comply with Section 409A of the Code may result in the early taxation (plus interest) to the participant of deferred compensation and the imposition of a 20% penalty on the participant on such deferred amounts included in the participant's income. We intend to structure awards under the LTIP in a manner that is designed to be exempt from or comply with Section 409A of the Code.

Change in Control

The acceleration of the exercisability or the vesting of a grant or award upon the occurrence of a change in control may result in an "excess parachute payment" within the meaning of Section 280G of the Code. A "parachute payment" occurs when an employee receives payments contingent upon a change in control that exceed an amount equal to three times his or her "base amount." The term "base amount" generally means the average annual compensation paid to such employee during the five-year period preceding the change in control. An "excess parachute payment" is the excess of all parachute payments made to the employee on account of a change in control over the employee's base amount. If any amount received by an employee is characterized as an excess parachute payment, the employee is subject to a 20% excise tax on the amount of the excess, and we are denied a deduction with respect to such excess payment.

New Plan Benefits

The number of Class A Shares that may be subject to new awards under the amended and restated LTIP is 3,500,000. There are also 1,143,575 shares of Class A Shares subject to awards already issued under the LTIP, but that remain subject to forfeiture. Per the terms of the LTIP, any shares subject to awards that are forfeited, terminated or settled in cash shall again be available for grant. The awards, if any, that will be granted to eligible participants under the LTIP are subject to the discretion of the Board or the Compensation Committee and, therefore, we cannot currently determine the benefits or number of shares subject to awards that may be granted in the future to participants under the LTIP. No awards or grants have been made under the LTIP that are contingent on stockholder approval of the LTIP. Therefore, a New Plan Benefits Table is not provided.

Equity Compensation Plan Information

The following table presents the securities authorized for issuance under the Jones Energy, Inc. 2013 Omnibus Incentive Plan (the "LTIP") as of December 31, 2015.

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)	—	—	2,303,615(2)
Equity compensation plans not approved by security holders	—	—	—
Total	—	—	2,303,615

(1) Our 2013 Omnibus Incentive Plan (the "LTIP") was approved by our board of directors in July 2013 and took effect on July 29, 2013. The LTIP was also approved by our shareholders at the Annual Meeting of Shareholders on July 10, 2013.

(2) The LTIP may consist of the following components: restricted stock, stock options, performance awards, restricted stock units, bonus stock awards, 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 3,850,000 shares of our Class A common stock. Our board of directors had approved total cumulative awards of 1,546,385 shares of restricted Class A common stock under the LTIP as of December 31, 2015, net of forfeitures and other adjustments that return previously awarded shares to the pool of remaining available shares.

Consequences of Failing to Approve the Proposal

Failure of the Company's stockholders to approve the amended and restated LTIP will not affect the rights of holders of existing awards under the LTIP. The LTIP shall continue regardless of the outcome of the stockholder vote. However, if the amended and restated LTIP is not approved, new grants under the LTIP will be limited and awards under the LTIP will not meet the requirements to be considered "performance-based compensation" under Section 162(m) of the Code. In addition, the Company may need to find other ways to attract and retain key employees.

Vote Required

Adoption of the proposal to amend and restate the LTIP, which includes an increase in the number of Class A Shares available under the LTIP, requires an affirmative vote of holders of a majority of the shares present in person or represented by proxy and entitled to vote at the Annual Meeting.

THE BOARD RECOMMENDS THAT THE STOCKHOLDERS VOTE "FOR" THE PROPOSAL TO AMEND AND RESTATE THE JONES ENERGY, INC. 2013 OMNIBUS INCENTIVE PLAN.

PROPOSAL FOUR:
APPROVAL OF THE AMENDED AND RESTATED JONES ENERGY, INC. 2013 SHORT-TERM INCENTIVE PLAN

On March 25, 2016, the Board adopted, pursuant to a recommendation from the Compensation Committee and subject to stockholder approval, an amended and restated STIP, which includes certain changes to performance goals. Shortly before our IPO, the Board adopted, and our stockholders approved, the current STIP, effective upon the consummation of the IPO. Annual cash bonus awards may be made to our employees under the STIP that are based on the achievement of certain business objectives and other criteria established by the Compensation Committee, which is the administrator of the STIP. Following our IPO, we were eligible for a post-initial public offering transition rule under which amounts paid under our STIP were exempt from the deduction limitations of Section 162(m) of the Code. In order to preserve our ability to grant fully tax-deductible performance-based awards, we are seeking stockholder approval of the material terms of the performance goals under the STIP for purposes of compliance with Section 162(m) of the Code.

The following is a summary of the STIP as amended and restated, and is qualified in its entirety by reference to the full text of the amended and restated STIP, which is attached as Appendix B to this proxy statement.

Plan Administration and Eligibility

The Compensation Committee of our Board administers the STIP. The Compensation Committee may generally delegate any of its authority (i) to select participants, (ii) grant awards and (iii) determine the value of awards granted to participants to any other committee of the Board or to our Chief Executive Officer. However, the Compensation Committee may not delegate its authority with respect to awards granted to a participant who is a "covered employee," as defined in Section 162(m) of the Code. Unless otherwise determined by the Compensation Committee, employees of the company or any of its subsidiaries who (a) are employed on the last day of the calendar year, which is referred to as the "plan year" and (b) are employed on the payment date of an award under the STIP are eligible for the payment of an award under the STIP.

Awards

The Compensation Committee determines the terms and conditions of awards and designates the recipients. Generally, awards are based on a percentage of actual base salary or gross wages paid to the participant during the plan year, including vacation, holiday and sick time. All or part of an award may be subject to conditions established by the Compensation Committee, which may include continuous service, achievement of specific individual and/or business objectives and other measures of performance.

Performance goals

Under the STIP, with respect to awards based on the achievement of business objectives, the Compensation Committee shall establish objective goals (i) no later than 90 days after the commencement of the period of service to which the performance goals relate or and (ii) prior to the completion of 25% of the performance period, and in any event, while the outcome is substantially uncertain. A performance goal is objective if a third party having knowledge of the relevant facts could determine whether the goal has been met.

Performance goals will be based upon targets established by the Compensation Committee with respect to one or more of the following financial or operational factors, as applied to the Company or a business unit, as applicable: (1) earnings per share; (2) production; (3) increase in cash flow; (4) increase in cash flow from operations; (5) increase in cash flow return; (6) return on net assets; (7) return on assets; (8) return on investment; (9) return on capital; (10) return on equity; (11) economic value added; (12) operating margin; (13) increase in production; (14) net income; (15) net income per share; (16) pretax earnings; (17) pretax earnings before interest, depreciation and amortization; (18) pretax earnings before interest, depreciation, amortization and exploration; (19) pretax operating earnings after interest expense and before incentives, service fees, and infrequent or unusual items; (20) total stockholder return; (21) debt reduction; (22) finding and development costs; (23) operating income; (24) internal rate of return; (25) safety; (26) operating expenses; (27) general and administrative expenses; (28) capital efficiency; (29) reserve replacement cost; and

(30) any of the above goals determined on an absolute or relative basis or as compared to the performance of a published or special index deemed applicable by the Committee including, but not limited to, the Standard & Poor's 500 Stock Index, Russell 2000 or a group of comparable companies.

Performance goals need not be based on an increased or positive result under a particular business criterion and could include, for example, maintaining the status quo or limiting economic losses. The Compensation Committee may decrease the amount payable pursuant to a performance award, but in no event may the Compensation Committee increase the amount payable pursuant to a performance award to a "covered employee" (as defined under Section 162(m) of the Code) other than as provided in Section 162(m) of the Code. The Compensation Committee may increase the amount of a performance award to any participant who is not a covered employee. In addition, the Compensation Committee may use such other performance goals and measures, including subjective measures, and make adjustments to performance goals and measures during the plan year, if the Compensation Committee determines that compliance with Section 162(m) of the Code is not desired. No participant may be granted performance awards that would result in the payment of more than $5,000,000 per plan year.

Clawback

Any award which is subject to recovery under any law, government regulation, or stock exchange listing requirement will be subject to the deductions and clawback that are required to be made pursuant to such law, government regulation, stock exchange listing requirement or any policy adopted by us.

Amendment and termination of plan

The STIP may be amended, modified, suspended, or terminated by our Board in order to address any changes in legal requirements or for any other purpose permitted by law, except that no amendment that would materially and adversely affect the rights of any participant under any award previously granted may be made without the consent of the participant, and no amendment may be effective prior to its approval by our stockholders, if such approval is required by law or an exchange.

New STIP Benefits

Future benefits that will be received under the STIP by particular individuals or groups are subject to the determination of the Compensation Committee and cannot be determined at this time.

Consequences of Failing to Approve the Proposal

The STIP shall continue regardless of the outcome of the stockholder vote. However, if the STIP is not approved, new grants under the STIP will not meet the requirements to be considered "performance-based compensation" under Section 162(m) of the Code.

Vote Required

Adoption of the proposal to approve the STIP requires an affirmative vote of holders of a majority of the shares present in person or represented by proxy and entitled to vote at the Annual Meeting.

THE BOARD RECOMMENDS THAT THE STOCKHOLDERS VOTE "FOR" THE PROPOSAL TO APPROVE THE AMENDED AND RESTATED JONES ENERGY, INC. 2013 SHORT-TERM INCENTIVE PLAN.

STOCKHOLDER PROPOSALS AND DIRECTOR NOMINATIONS

Stockholders may propose matters to be presented at stockholders' meetings and may also recommend persons for nomination or nominate persons to be directors, subject to the formal procedures that have been established under our Bylaws. Our Bylaws are available in our SEC filings which can be accessed on our website at www.jonesenergy.com under the Corporate Governance tab in the Investor Relations section. Stockholders are urged to review all applicable rules and consult legal counsel before submitting a nomination or proposal to Jones Energy.

Proposals for 2017 Annual Meeting

Pursuant to rules promulgated by the SEC, any proposals of stockholders of our company intended to be presented at the 2017 annual meeting of stockholders and included in our Proxy Statement and form of proxy relating to that meeting must be received at our principal executive offices, 807 Las Cimas Parkway, Suite 350, Austin, Texas 78746, no later than January 4, 2017. Such proposals must be in conformity with all applicable legal provisions, including Rule 14a-8 of the General Rules and Regulations under the Exchange Act.

If you wish to present a stockholder proposal at the 2017 annual meeting of stockholders that is not the subject of a proposal pursuant to Rule 14a-8 of the Exchange Act, you must follow the procedures outlined in Section 2.9(c) of our Bylaws. These procedures include the requirement that your proposal must be delivered to Jones Energy's Corporate Secretary at the address shown on the cover page of this proxy statement not later than the close of business on the 90th day or earlier than the close of business on the 120th day prior to the first anniversary of the preceding year's annual meeting. If the date of the annual meeting is more than 30 days before or more than 70 days after such anniversary date, your notice must be delivered not earlier than the close of business on the 120th day prior to such annual meeting and not later than the close of business on the later of the 90th day prior to such annual meeting or the 10th day following the day we publicly announce the date of the 2017 annual meeting of stockholders. **For a proposal of business to be considered at the 2017 annual meeting of stockholders, a stockholder's notice should be properly submitted to our Corporate Secretary at our principal executive offices, 807 Las Cimas Parkway, Suite 350, Austin, Texas 78746, no later than February 3, 2017, but not earlier than January 4, 2017.**

Nominations for 2017 Annual Meeting

If you wish to recommend to the Board's Nominating Committee the nomination of a person for election to the Board, you must follow the procedures outlined in Section 3.5(a) of our Bylaws.

These procedures include the requirement that your nominations must be delivered to Jones Energy's Corporate Secretary at the address shown on the cover page of this proxy statement not later than the close of business on the 90th day or earlier than the close of business on the 120th day prior to the first anniversary of the preceding year's annual meeting. If the date of the annual meeting is more than 30 days before or more than 70 days after such anniversary date, your notice must be delivered not earlier than the close of business on the 120th day prior to such annual meeting and not later than the close of business on the later of the 90th day prior to such annual meeting or the 10th day following the day we publicly announce the date of the 2017 annual meeting of stockholders. If the number of directors to be elected to the Board at the 2017 annual meeting of stockholders is increased and there is no prior notice or public disclosure by us naming all of the nominees for director or specifying the size of the increased Board at least 100 days prior to the anniversary date of the Annual Meeting, a stockholder's notice shall also be considered timely, but only with respect to

nominees for any new positions created by such increase, if it shall be delivered to our principal executive offices not later than the close of business on the 10th day following the earlier of the day on which the notice of such meeting was mailed to stockholders of the Corporation or the day on which such public disclosure was made. **For a nomination to be considered at the 2017 annual meeting of stockholders, a stockholder's notice should be properly submitted to our Corporate Secretary at our principal executive offices, 807 Las Cimas Parkway, Suite 350, Austin, Texas 78746, no later than February 3, 2017, but not earlier than January 4, 2017.**

SOLICITATION AND MAILING OF PROXIES

The expense of preparing, printing and mailing this Proxy Statement and the proxies solicited hereby will be borne by us. In addition to the use of the mail, proxies may be solicited by our representatives in person or by telephone, electronic mail or facsimile transmission. These representatives will not be additionally compensated for such solicitation, but may be reimbursed for out-of-pocket expenses incurred. If undertaken, we expect the expenses of such solicitation by our representatives to be nominal. We will also request brokerage firms, banks, nominees, custodians and fiduciaries to forward proxy materials to the beneficial owners of our shares as of the Record Date and will provide reimbursement for the cost of forwarding the proxy materials in accordance with customary practice.

If a stockholder wishes to give such holder's proxy to someone other than the names appearing in the proxy card, the names appearing in the proxy card must be crossed out and the name of another individual or individuals (not more than three) inserted. The signed card must be presented at the Annual Meeting by the individual or individuals representing such stockholder.

As a matter of policy, proxies, ballots, and voting tabulations that identify individual stockholders are kept private by us. Such documents are available for examination only by the inspectors of election and certain personnel associated with processing proxy cards and tabulating the vote. The vote of any stockholder is not disclosed except as necessary to meet legal requirements.

STOCKHOLDER LIST

In accordance with the Delaware General Corporation Law, the Company will maintain at its corporate offices in Austin, Texas, a list of the stockholders entitled to vote at the Annual Meeting. The list will be open to the examination of any stockholder, for purposes germane to the Annual Meeting, during ordinary business hours for ten days before the Annual Meeting.

HOUSEHOLDING

The SEC permits a single set of annual reports and proxy statements to be sent to any household at which two or more stockholders reside if they appear to be members of the same family. Each stockholder continues to receive a separate proxy card. This procedure, referred to as householding, reduces the volume of duplicate information stockholders receive and reduces mailing and printing expenses. As a result, if you hold your shares through a broker and you reside at an address at which two or more stockholders reside, you will likely be receiving only one annual report and Proxy Statement unless any stockholder at that address has given the broker contrary instructions. However, if any such beneficial stockholder residing at such an address wishes to receive a separate annual report or Proxy Statement in the future, or if any such beneficial stockholder that receives separate annual reports or Proxy Statements wishes to receive a single annual report or Proxy Statement in the future, that stockholder should contact their broker or send a request to our principal executive offices, 807 Las Cimas Parkway, Suite 350, Austin, Texas 78746, Attn: Corporate Secretary. We will deliver, promptly upon written request to the Corporate Secretary, a separate copy of the 2015 Annual Report and this Proxy Statement to a beneficial stockholder at a shared address to which a single copy of the documents was delivered.

WHERE YOU CAN FIND MORE INFORMATION ABOUT US

We file annual, quarterly and current reports and proxy statements with the SEC. Our SEC filings are available to the public over the internet at the SEC's website at *www.sec.gov*. You may also read and copy any document that we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, D.C. 20549. You can call the SEC at 1-800-SEC-0330 for further information on the public reference room and its copy charges. We maintain a website at *www.jonesenergy.com*, where we post our SEC filings.

You may request copies of our filings, including any documents incorporated by reference in this Proxy Statement as described below, without charge, by calling our Investor Relations representative at 512.493.4834 or write to Investor Relations, 807 Las Cimas Parkway, Suite 350, Austin, Texas 78746.

If you would like to request documents from us, please do so at least ten business days before the date of the Annual Meeting in order to receive timely delivery of the documents before the Annual Meeting. If you request any incorporated documents from us, we will mail them to you by first class mail or other equally prompt means within one business day of receipt of your request, provided that we will not mail any exhibits to the information that is incorporated by reference unless such exhibits are specifically incorporated by reference into the information that this Proxy Statement incorporates.

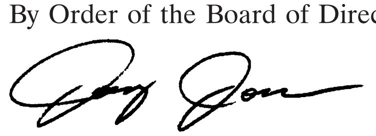
You should rely only on the information contained or incorporated by reference in this Proxy Statement to vote your units at the Annual Meeting. We have not authorized anyone to provide you with information that is different from what is contained or incorporated by reference in this Proxy Statement.

The information contained in this document or any document incorporated by reference herein speaks only as of the date indicated on the cover of this document or the document incorporated by reference unless the information specifically indicates that another date applies.

OTHER MATTERS FOR 2016 ANNUAL MEETING

As of the date of this Proxy Statement, our Board knows of no matters to be acted upon at the Annual Meeting other than the proposals included in the accompanying notice and described in this Proxy Statement. If any other matter requiring a vote of stockholders arises, including a question of adjourning the Annual Meeting, the persons named as proxies in the accompanying proxy card will have the discretion to vote thereon according to their best judgment of what they consider to be in the best interests of our company. The accompanying proxy card confers discretionary authority to take action with respect to any additional matters that may come before the Annual Meeting or any adjournment or postponement thereof.

By Order of the Board of Directors,



Jonny Jones
Founder, Chairman and Chief Executive Officer

Austin, Texas
April 1, 2016

Appendix A

JONES ENERGY, INC.
2013 OMNIBUS INCENTIVE PLAN

(Amended and Restated as of May 4, 2016)

JONES ENERGY, INC.
2013 OMNIBUS INCENTIVE PLAN
(Amended and Restated as of May 4, 2016)

Table of Contents

		Page
1.	Plan	A-1
2.	Objectives	A-1
3.	Definitions	A-1
4.	Eligibility	A-4
5.	Common Stock Available for Awards	A-4
6.	Administration	A-5
7.	Delegation of Authority	A-6
8.	Employee Awards	A-6
9.	Consultant and Director Awards	A-9
10.	Award Payment; Dividends and Dividend Equivalents	A-10
11.	Option Exercise	A-10
12.	Taxes	A-10
13.	Amendment, Modification, Suspension or Termination	A-10
14.	Assignability	A-11
15.	Adjustments	A-11
16.	Restrictions	A-12
17.	Unfunded Plan	A-12
18.	Code Section 409A	A-12
19.	Awards to Foreign Nationals and Employees Outside the United States	A-13
20.	Governing Law	A-13
21.	Right to Continued Service or Employment	A-13
22.	Clawback Right	A-13
23.	Usage	A-13
24.	Headings	A-13
25.	Effectiveness	A-13

JONES ENERGY, INC.
2013 OMNIBUS INCENTIVE PLAN

(Amended and Restated as of May 4, 2016)

1. ***Plan***. Jones Energy, Inc., a Delaware corporation (the "*Company*"), established this Jones Energy, Inc. 2013 Omnibus Incentive Plan (this "*Plan*"), effective as of July 29, 2013 (the "*Effective Date*"). This Plan was subsequently amended and restated in its entirety effective as of May 4, 2016 to increase the number of shares reserved under this Plan and to make certain design changes. This Plan shall continue in effect for a term of 10 years after the Effective Date unless sooner terminated by action of the Board of Directors of the Company.

2. ***Objectives***. This Plan is designed to attract and retain employees and consultants of the Company and its Subsidiaries (as defined herein), to attract and retain qualified non-employee directors of the Company, to encourage the sense of proprietorship of such employees, consultants and directors and to stimulate the active interest of such persons in the development and financial success of the Company and its Subsidiaries. These objectives are to be accomplished by making Awards under this Plan and thereby providing Participants (as defined herein) with a proprietary interest in the growth and performance of the Company and its Subsidiaries.

3. ***Definitions***. As used herein, the terms set forth below shall have the following respective meanings:

"*Authorized Officer*" means the Chairman of the Board, the Chief Executive Officer of the Company (or any other senior officer of the Company to whom any of such individuals shall delegate the authority to execute any Award Agreement).

"*Award*" means the grant of any Option, Stock Appreciation Right, Stock Award, or Cash Award, any of which may be structured as a Performance Award, whether granted singly, in combination or in tandem, to a Participant pursuant to such applicable terms, conditions, and limitations as the Committee may establish in accordance with the objectives of this Plan.

"*Award Agreement*" means the document (in written or electronic form) communicating the terms, conditions and limitations applicable to an Award. The Committee may, in its discretion, require that the Participant execute such Award Agreement, or may provide for procedures through which Award Agreements are made effective without execution. Any Participant who is granted an Award and who does not affirmatively reject the applicable Award Agreement shall be deemed to have accepted the terms of Award as embodied in the Award Agreement.

"*Board*" means the Board of Directors of the Company.

"*Cash Award*" means an Award denominated in cash.

"*Change in Control*" means a Change in Control as defined in *Attachment A* to this Plan.

"*Code*" means the Internal Revenue Code of 1986, as amended from time to time.

"*Committee*" means the Compensation Committee of the Board, and any successor committee thereto or such other committee of the Board as may be designated by the Board to administer this Plan in whole or in part including any subcommittee of the Board as designated by the Board.

"*Common Stock*" means the Class A Common Stock, par value $0.001 per share, of the Company.

"*Company*" means Jones Energy, Inc., a Delaware corporation, or any successor thereto.

"*Consultant*" means an individual providing services to the Company or any of its Subsidiaries, other than an Employee or a Director, and an individual who has agreed to become a consultant of the Company or any of its Subsidiaries and actually becomes such a consultant following such date of agreement.

"*Consultant Award*" means the grant of any Award (other than an Incentive Stock Option), whether granted singly, in combination, or in tandem, to a Participant who is a Consultant pursuant to such applicable terms, conditions, and limitations established by the Committee.

"*Covered Employee*" means any Employee who is or may be a "covered employee," as defined in Code Section 162(m).

"*Director*" means an individual serving as a member of the Board who is not an Employee or a Consultant and an individual who has agreed to become a director of the Company or any of its Subsidiaries and actually becomes such a director following such date of agreement.

"*Director Award*" means the grant of any Award (other than an Incentive Stock Option), whether granted singly, in combination, or in tandem, to a Participant who is a Director pursuant to such applicable terms, conditions, and limitations established by the Board.

"*Disability*" means (1) if the Participant is an Employee, a disability that entitles the Employee to benefits under the Company's long-term disability plan, as may be in effect from time to time, as determined by the plan administrator of the long-term disability plan or (2) if the Participant is a Director or a Consultant, a disability whereby the Director or Consultant is unable to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of not less than 12 months. Notwithstanding the foregoing, if an Award is subject to Code Section 409A, the definition of Disability shall conform to the requirements of Treasury Regulation § 1.409A-3(i)(4)(i).

"*Dividend Equivalents*" means, in the case of Restricted Stock Units or Performance Units, an amount equal to all dividends and other distributions (or the economic equivalent thereof) that are payable to stockholders of record during the Restriction Period or performance period, as applicable, on a like number of shares of Common Stock that are subject to the Award.

"*Employee*" means an employee of the Company or any of its Subsidiaries and an individual who has agreed to become an employee of the Company or any of its Subsidiaries and actually becomes such an employee following such date of agreement.

"*Employee Award*" means the grant of any Award, whether granted singly, in combination, or in tandem, to an Employee pursuant to such applicable terms, conditions, and limitations established by the Committee.

"*Exchange Act*" means the Securities Exchange Act of 1934, as amended from time to time.

"*Exercise Price*" means the price at which a Participant may exercise his right to receive cash or Common Stock, as applicable, under the terms of an Award.

"*Fair Market Value*" of a share of Common Stock means, as of a particular date, (1) if shares of Common Stock are listed on a national securities exchange, the closing sales price per share of Common Stock on the consolidated transaction reporting system for the principal national securities exchange on which shares of Common Stock are listed on that date, or, if there shall have been no such sale so reported on that date, on the last preceding date on which such a sale was so reported, (2) if the Common Stock is not so listed, the average of the closing bid and asked price on that date, or, if there are no quotations available for such date, on the last preceding date on which such quotations shall be available, as reported by an inter-dealer quotation system, (3) if shares of Common Stock are not publicly traded, the most recent value determined by an independent appraiser appointed by the Committee for such purpose, or (4) if none of the above

are applicable, the Fair Market Value of a share of Common Stock as determined in good faith by the Committee; *provided, however*, that with respect to any Awards granted on the date of the initial public offering of the Common Stock, Fair Market Value shall mean the opening sales price per share price of the Common Stock offered in connection with such initial public offering.

"*Grant Date*" means the date an Award is granted to a Participant pursuant to this Plan.

"*Incentive Stock Option*" means an Option that is intended to comply with the requirements set forth in Code Section 422.

"*Nonqualified Stock Option*" means an Option that is not intended to comply with the requirements set forth in Code Section 422.

"*Option*" means a right to purchase a specified number of shares of Common Stock at a specified Exercise Price, which is either an Incentive Stock Option or a Nonqualified Stock Option.

"*Participant*" means an Employee, Consultant or Director to whom an Award has been made under this Plan.

"*Performance Award*" means an Award made pursuant to this Plan to a Participant which is subject to the attainment of one or more Performance Goals.

"*Performance Goal*" means one or more standards established by the Committee to determine in whole or in part whether a Performance Award shall be earned.

"*Performance Unit*" means a unit evidencing the right to receive in specified circumstances one share of Common Stock or equivalent value in cash, the value of which at the time it is settled is determined as a function of the extent to which established performance criteria have been satisfied.

"*Performance Unit Award*" means an Award in the form of Performance Units.

"*Plan*" means the Jones Energy, Inc. 2013 Omnibus Incentive Plan, as amended and restated as of May 4, 2016 and as thereafter amended from time to time.

"*Qualified Performance Awards*" has the meaning set forth in Paragraph 8(a)(vii)(B).

"*Restricted Stock*" means a share of Common Stock that is restricted or subject to forfeiture provisions.

"*Restricted Stock Award*" means an Award in the form of Restricted Stock.

"*Restricted Stock Unit*" means a unit evidencing the right to receive in specified circumstances one share of Common Stock or equivalent value in cash that is restricted or subject to forfeiture provisions.

"*Restricted Stock Unit Award*" means an Award in the form of Restricted Stock Units.

"*Restriction Period*" means a period of time beginning as of the date upon which a Restricted Stock Award or Restricted Stock Unit Award is made pursuant to this Plan and ending as of the date upon which such Award is no longer restricted or subject to forfeiture provisions.

"*Stock Appreciation Right*" or "*SAR*" means a right to receive a payment, in cash or Common Stock, equal to the excess of the Fair Market Value of a specified number of shares of Common Stock on the date the right is exercised over a specified Exercise Price.

"*Stock Award*" means an Award in the form of shares of Common Stock, including a Restricted Stock Award, and a Restricted Stock Unit Award or Performance Unit Award that may be settled in shares of Common Stock, and excluding Options and SARs.

"*Stock-Based Award Limitations*" has the meaning set forth in Paragraph 5.

"*Subsidiary*" means (1) in the case of a corporation, any corporation of which the Company directly or indirectly owns shares representing 50% or more of the combined voting power of the shares of all classes or series of capital stock of such corporation which have the right to vote generally on matters submitted to a vote of the stockholders of such corporation, and (2) in the case of a partnership or other business entity not organized as a corporation, any such business entity of which the Company directly or indirectly owns 50% or more of the voting, capital or profits interests (whether in the form of partnership interests, membership interests or otherwise).

4. ***Eligibility***.

(a) *Employees.* All Employees are eligible for Employee Awards under this Plan, *provided, however*, that if the Committee makes an Employee Award to an individual whom it expects to become an Employee following the Grant Date of such Award, such Award shall be subject to (among other terms and conditions) the individual actually becoming an Employee.

(b) *Consultants.* All Consultants are eligible for Consultant Awards under this Plan, *provided, however*, that if the Committee makes a Consultant Award to an individual whom it expects to become a Consultant following the Grant Date of such Award, such Award shall be subject to (among other terms and conditions) the individual actually becoming a Consultant.

(c) *Directors.* All Directors are eligible for Director Awards under this Plan, *provided, however*, that if the Board makes a Director Award to an individual whom it expects to become a Director following the Grant Date of such Award, such Award shall be subject to (among other terms and conditions) the individual actually becoming a Director.

The Committee (or the Board, in the case of Director Awards) shall determine the type or types of Awards to be made under this Plan and shall designate from time to time the Employees, Consultants or Directors who are to be granted Awards under this Plan.

5. ***Common Stock Available for Awards***. Subject to the provisions of Paragraph 15 hereof, there shall be available for Awards under this Plan granted wholly or partly in Common Stock (including rights or Options that may be exercised for or settled in Common Stock) an aggregate of 7,350,000 shares of Common Stock (the "Maximum Share Limit"), all of which shall be available for Incentive Stock Options. The Maximum Share Limit reflects the total of the initial number of shares of Common Stock approved under this Plan on July 29, 2013 of 3,850,000 shares and the additional shares of Common Stock approved on May 4, 2016 of 3,500,000 shares.

Awards settled in cash shall not reduce the Maximum Share Limit under the Plan. If an Award expires or is terminated, cancelled or forfeited, the shares of Common Stock associated with the expired, terminated, cancelled or forfeited Award shall again be available for Awards under the Plan, and the Maximum Share Limit shall be increased by the number of shares subject to such Award. The following shares of Common Stock shall also become available again for Awards under the Plan other than Awards of Incentive Stock Options:

(i) Shares of Common Stock that are tendered by a Participant or withheld as full or partial payment of minimum withholding taxes or as payment for the Exercise Price of an Award; and

(ii) Shares of Common Stock reserved for issuance upon grant of an SAR, to the extent the number of reserved shares of Common Stock exceeds the number of shares of Common Stock actually issued upon exercise or settlement of such SAR .

The foregoing notwithstanding, subject to New York Stock Exchange listing requirements, the Maximum Share Limit shall not be reduced by (x) shares of Common Stock issued under Awards granted in assumption, substitution or exchange for previously granted awards of a company acquired by the Company and (y) available shares under a stockholder approved plan of an acquired company (as appropriately adjusted to reflect the transaction) and such shares shall be available for Awards under the Plan.

The Board and the appropriate officers of the Company shall from time to time take whatever actions are necessary to file any required documents with governmental authorities, stock exchanges and transaction reporting systems to ensure that shares of Common Stock are available for issuance pursuant to Awards.

Notwithstanding anything to the contrary contained in this Plan, the following limitations shall apply to any Awards made hereunder (and if an Award is cancelled, the cancelled Award shall continue to be counted toward the applicable limitation in this Section, to the extent required by Code Section 162(m)):

(a) No Employee may be granted during any calendar year Awards consisting of Options or SARs that are exercisable for more than 2,500,000 shares of Common Stock;

(b) No Employee may be granted during any calendar year Qualified Performance Awards that are Stock Awards covering or relating to more than 2,500,000 shares of Common Stock (the limitation set forth in this clause (b), together with the limitation set forth in clause (a) above, being hereinafter collectively referred to as the "*Stock-Based Award Limitations*");

(c) No Employee may be granted during any calendar year Qualified Performance Awards that are (1) Cash Awards or (2) Restricted Stock Unit Awards or Performance Unit Awards that may be settled solely in cash having a value determined on the Grant Date in excess of $5,000,000; and

(d) No Director may be granted during any calendar year Awards having a value determined on the Grant Date (computed in accordance with applicable financial accounting rules) when added to all cash paid to the Director during the same calendar year in excess of $500,000.

Shares delivered by the Company in settlement of Awards may be authorized and unissued shares of Common Stock, shares of Common Stock held in the treasury of the Company, shares of Common Stock purchased on the open market or by private purchase or any combination of the foregoing.

6. ***Administration***.

(a) *Authority of the Committee.* Except as otherwise provided in this Plan with respect to actions or determinations by the Board, this Plan shall be administered by the Committee; *provided, however*, that (i) any and all members of the Committee shall satisfy any independence requirements prescribed by any stock exchange on which the Company lists its Common Stock; (ii) Awards may be granted to individuals who are subject to Section 16(b) of the Exchange Act only if the Committee is comprised solely of two or more "Non-Employee Directors" as defined in Securities and Exchange Commission Rule 16b-3 (as amended from time to time, and any successor rule, regulation or statute fulfilling the same or similar function); and (iii) any Award intended to qualify for the "performance-based compensation" exception under Code Section 162(m) shall be granted only if the Committee is comprised solely of two or more "outside directors" within the meaning of Code Section l62(m) and regulations pursuant thereto. Subject to the provisions hereof, the Committee shall have full and exclusive power and authority to administer this Plan and to take all actions that are specifically contemplated hereby or are necessary or appropriate in connection with the administration hereof. The Committee shall also have full and exclusive power to interpret this Plan and to adopt such rules, regulations and guidelines for carrying out this Plan as it may deem necessary or proper, all of which powers shall be exercised in the best interests of the Company and in keeping with the objectives of this Plan. Subject to Paragraph 6(c) hereof, the Committee may, in its discretion, provide for the extension of the exercisability of an Award, accelerate the vesting or exercisability of an Award, eliminate or make less restrictive any restrictions contained in an Award, waive any restriction or other provision of this Plan or an Award or otherwise amend or modify an Award in any manner that is, in either case, (1) not materially adverse to the Participant to whom such Award was granted, (2) consented to by such Participant or (3) authorized by Paragraph 15(c) hereof; *provided, however*, that except as expressly provided in Paragraph 8(a)(i) or 8(a)(ii) hereof, no such action shall permit the term of any Option or SAR to be greater than 10 years from its Grant Date. The Committee may correct any defect or supply any omission or reconcile any inconsistency in this Plan or in any Award Agreement in the manner and to the extent the Committee deems necessary or desirable to further this Plan's purposes. Any decision of the Committee in the interpretation and administration of this Plan shall lie within its sole and absolute discretion and shall be final, conclusive and binding on all parties concerned. The Board shall have the same powers as the Committee with respect to Director Awards.

(b) *Indemnity.* No member of the Board or the Committee or officer of the Company to whom the Committee has delegated authority in accordance with the provisions of Paragraph 7 of this Plan shall be liable for anything done or omitted to be done by him, by any member of the Board or the Committee or by any officer of the Company in connection with the performance of any duties under this Plan, except for his own willful misconduct or as expressly provided by statute.

(c) *Prohibition on Repricing of Awards.* Subject to the provisions of Paragraph 15 hereof, the terms of outstanding Award Agreements may not be amended without the approval of the Company's stockholders so as to (i) reduce the Exercise Price of any outstanding Options or SARs or (ii) cancel any outstanding Options or SARs in exchange for cash or other Awards, or Options or SARs with an Exercise Price that is less than the Exercise Price of the original Options or SARs.

7. ***Delegation of Authority***. The Committee may delegate any of its authority to grant Awards to Employees who are not subject to Section 16(b) of the Exchange Act and Consultants, subject to Paragraph 6(a) above, to the Board or to any other committee of the Board, provided such delegation is made in writing and specifically sets forth such delegated authority. The Committee may also delegate to an Authorized Officer authority to execute on behalf of the Company any Award Agreement. The Committee and the Board, as applicable, may engage or authorize the engagement of a third party administrator to carry out administrative functions under this Plan. Any such delegation hereunder shall only be made to the extent permitted by applicable law.

8. ***Employee Awards***.

(a) The Committee shall determine the type or types of Employee Awards to be made under this Plan and shall designate from time to time the Employees who are to be the recipients of such Awards. Each Award shall be embodied in an Award Agreement, which shall contain such terms, conditions and limitations as shall be determined by the Committee, in its sole discretion, and, if required by the Committee, shall be signed by the Participant to whom the Award is granted and by an Authorized Officer for and on behalf of the Company. Awards may consist of those listed in this Paragraph 8(a) hereof and may be granted singly, in combination or in tandem. Awards may also be made in combination or in tandem with, in replacement of, or as alternatives to, grants or rights under this Plan or any other plan of the Company or any of its Subsidiaries, including the plan of any acquired entity; *provided, however*, that, except as contemplated in Paragraph 15 hereof, no Option or SAR may be issued in exchange for the cancellation of an Option or SAR with a

higher Exercise Price nor may the Exercise Price of any Option or SAR be reduced. All or part of an Award may be subject to conditions established by the Committee. Upon the termination of employment by a Participant who is an Employee, any unexercised, unvested or unpaid Awards shall be treated as set forth in the applicable Award Agreement or in any other written agreement the Company has entered into with the Participant.

(i) *Options.* An Employee Award may be in the form of an Option. An Option awarded pursuant to this Plan may consist of either an Incentive Stock Option or a Nonqualified Stock Option. The price at which shares of Common Stock may be purchased upon the exercise of an Option shall be not less than the Fair Market Value of the Common Stock on the Grant Date, subject to adjustment as provided in Paragraph 15 hereof. The term of an Option shall not exceed 10 years from the Grant Date; *provided, however*, if the term of a Nonqualified Option (but not an Incentive Option) expires when trading in the Common Stock is prohibited by law or the Company's insider trading policy, then the term of such Nonqualified Option shall expire on the 30th day after the expiration of such prohibition. Subject to the foregoing provisions, the terms, conditions and limitations applicable to any Option, including, but not limited to, the term of any Option and the date or dates upon which the Option becomes vested and exercisable, shall be determined by the Committee.

(ii) *Stock Appreciation Rights.* An Employee Award may be in the form of an SAR. The Exercise Price for an SAR shall not be less than the Fair Market Value of the Common Stock on the Grant Date, subject to adjustment as provided in Paragraph 15 hereof. The holder of a tandem SAR may elect to exercise either the Option or the SAR, but not both. The exercise period for an SAR shall extend no more than 10 years after the Grant Date; *provided, however*, if the term of an SAR expires when trading in the Common Stock is prohibited by law or the Company's insider trading policy, then the term of such SAR shall expire on the 30th day after the expiration of such prohibition. Subject to the foregoing provisions, the terms, conditions, and limitations applicable to any SAR, including, but not limited to, the term of any SAR and the date or dates upon which the SAR becomes vested and exercisable, shall be determined by the Committee.

(iii) *Stock Awards.* An Employee Award may be in the form of a Stock Award. The terms, conditions and limitations applicable to any Stock Award, including, but not limited to, vesting or other restrictions, shall be determined by the Committee, and subject to the minimum Restriction Period and performance period requirements and any other applicable requirements described in this Paragraph 8(a) hereof.

(iv) *Restricted Stock Unit Awards.* An Employee Award may be in the form of a Restricted Stock Unit Award. The terms, conditions and limitations applicable to a Restricted Stock Unit Award, including, but not limited to, the Restriction Period, shall be determined by the Committee. Subject to the terms of this Plan, the Committee, in its sole discretion, may settle Restricted Stock Units in the form of cash or in shares of Common Stock (or in a combination thereof) equal to the value of the vested Restricted Stock Units.

(v) *Performance Unit Awards.* An Employee Award may be in the form of a Performance Unit Award. Each Performance Unit shall have an initial value that is established by the Committee on the Grant Date. Subject to the terms of this Plan, after the applicable performance period has ended, the Participant shall be entitled to receive settlement of the value and number of Performance Units earned by the Participant over the performance period, to be determined as a function of the extent to which the corresponding performance goals have been achieved. Settlement of earned Performance Units shall be as determined by the Committee and as evidenced in an Award Agreement. Subject to the terms of this Plan, the Committee, in its sole discretion, may settle earned Performance Units in the form of cash or in shares of Common Stock (or in a combination thereof) equal to the value of the earned Performance Units as soon as practicable after the end of the performance period and following the Committee's determination of actual performance against the performance measures and related goals established by the Committee.

(vi) *Cash Awards.* An Employee Award may be in the form of a Cash Award. The terms, conditions and limitations applicable to a Cash Award, including, but not limited to, vesting or other restrictions, shall be determined by the Committee.

(vii) *Performance Awards.* Without limiting the type or number of Awards that may be made under the other provisions of this Plan, an Employee Award may be in the form of a Performance Award. The terms, conditions and limitations applicable to an Award that is a Performance Award shall be determined by the Committee. The Committee shall set Performance Goals in its discretion which, depending on the extent to which they are met, will determine the value and/or amount of Performance Awards that will be paid out to the Participant and/or the portion of an Award that may be exercised.

(A) *Nonqualified Performance Awards.* Performance Awards granted to Employees that are not intended to qualify as qualified performance-based compensation under Code Section 162(m) shall be based on achievement of such Performance Goals and be subject to such terms, conditions and restrictions as the Committee or its delegate shall determine.

(B) *Qualified Performance Awards.* Performance Awards granted to Employees under this Plan that are intended to qualify as qualified performance-based compensation under Code Section 162(m) shall be paid, vested or otherwise deliverable solely on account of the attainment of one or more pre-established, objective Performance Goals established by the Committee (1) no later than 90 days after the commencement of the period of service to which the Performance Goal relates and (2) prior to the lapse of 25% of the period of service (as scheduled in good faith at the time the goal is established), and in any event while the outcome is substantially uncertain. A Performance Goal is objective if a third party having knowledge of the relevant facts could determine whether the goal is met. One or more of such goals may apply to the Employee, one or more business units, divisions or sectors of the Company, or the Company as a whole, and if so desired by the Committee, by comparison with a peer group of companies. Any Performance Goals that are financial metrics, may be determined in accordance with U.S. Generally Accepted Accounting Principles ("*GAAP*"), in accordance with accounting principles established by the International Accounting Standards Board ("*IASB Principles*"), or may be adjusted when established to include or exclude any items otherwise includable or excludable under GAAP or under IASB Principles. A Performance Goal shall include one or more of the following: (1) earnings per share; (2) production; (3) increase in cash flow; (4) increase in cash flow from operations; (5) increase in cash flow return; (6) return on net assets; (7) return on assets; (8) return on investment; (9) return on capital; (10) return on equity; (11) economic value added; (12) operating margin; (13) increase in production; (14) net income; (15) net income per share; (16) pretax earnings; (17) pretax earnings before interest, depreciation and amortization; (18) pretax earnings before interest, depreciation, amortization and exploration; (19) pretax operating earnings after interest expense and before incentives, service fees, and infrequent or unusual items; (20) total stockholder return; (21) debt reduction; (22) finding and development costs; (23) operating income; (24) internal rate of return; (25) safety; (26) operating expenses; (27) general and administrative expenses; (28) capital efficiency; (29) reserve replacement cost; and (30) any of the above goals determined on an absolute or relative basis or as compared to the performance of a published or special index deemed applicable by the Committee including, but not limited to, the Standard & Poor's 500 Stock Index, Russell 2000 or a group of comparable companies.

Unless otherwise stated, such a Performance Goal need not be based upon an increase or positive result under a particular business criterion and could include, for example, maintaining the status quo or limiting economic losses (measured, in each case, by reference to specific business criteria). In interpreting Plan provisions applicable to Qualified Performance Awards, it is the intent of this Plan to conform with the standards of Code Section 162(m) and Treasury Regulation § 1.162-27(e)(2)(i), as to grants to Covered Employees and the Committee in establishing such goals and interpreting this Plan shall be guided by such provisions.

Prior to the payment of any compensation based on the achievement of Performance Goals applicable to Qualified Performance Awards, the Committee must certify in writing that applicable Performance Goals and any of the material terms thereof were, in fact, satisfied. For this purpose, approved minutes of the Committee meeting in which the certification is made shall be treated as such written certification. Subject to the foregoing provisions, the terms, conditions and limitations applicable to any Qualified Performance Awards made pursuant to this Plan shall be determined by the Committee. At the time it establishes the Performance Goals, the Committee may provide for the impact of an event or occurrence which the Committee determines should appropriately be included or excluded, including any of the following: (a) asset write-downs, (b) litigation or claim judgments or settlements, (c) the effect of changes in tax laws, accounting principles, or other laws or provisions affecting reported results, (d) any reorganization and restructuring programs, (e) infrequent and unusual items as defined by the Company's auditors and/or in management's discussion and analysis of financial condition and results of operations appearing in the Company's annual report to stockholders for the applicable year, (f) acquisitions or divestitures, (g) foreign exchange gains and losses and (h) settlement of hedging activities.

(C) *Adjustment of Performance Awards.* Awards that are intended to be Qualified Performance Awards may not be adjusted upward. The Committee may retain the discretion to adjust such Performance Awards downward, either on a formula or discretionary basis or any combination, as the Committee determines.

9. ***Consultant and Director Awards.***

(a) *Consultant Awards.* The Committee has the sole authority to grant Consultant Awards from time to time in accordance with this Paragraph 9(a). Consultant Awards may consist of the forms of Award described in Paragraph 8, with the exception of Incentive Stock Options, may be granted singly, in combination, or in tandem and shall be granted subject to such terms and conditions as specified in Paragraph 8. Each Consultant Award shall be embodied in an Award Agreement, which shall contain such terms, conditions, and limitations as shall be determined by the Committee, in its sole discretion.

(b) *Director Awards.* The Board has the sole authority to grant Director Awards from time to time in accordance with this Paragraph 9(b). Director Awards may consist of the forms of Award described in Paragraph 8, with the exception of Incentive Stock Options, may be granted singly, in combination, or in tandem and shall be granted subject to such terms and conditions as specified in Paragraph 8. Each Director Award may, in the discretion of the Board, be embodied in an Award Agreement, which shall contain such terms, conditions, and limitations as shall be determined by the Board, in its sole discretion.

10. ***Award Payment; Dividends and Dividend Equivalents.***

(a) *General.* Payment of Awards may be made in the form of cash or Common Stock, or a combination thereof, and may include such restrictions as the Committee (or the Board, in the case of Director Awards) shall determine, including, but not limited to, in the case of Common Stock, restrictions on transfer and forfeiture provisions. For a Restricted Stock Award, the certificates evidencing the shares of such Restricted Stock (to the extent that such shares are so evidenced) shall contain appropriate legends and restrictions that describe the terms and conditions of the restrictions applicable thereto. For a Restricted Stock Unit Award that may be settled in shares of Common Stock, the shares of Common Stock that may be issued at the end of the Restriction Period shall be evidenced by book entry registration or in such other manner as the Committee may determine.

(b) *Dividends and Dividend Equivalents.* Rights to (1) dividends will be extended to and made part of any Restricted Stock Award and (2) Dividend Equivalents may be extended to and made part of any Restricted Stock Unit Award and Performance Unit Award, subject in each case to such terms, conditions and restrictions as the Committee may establish; *provided, however*, that no such dividends or Dividend Equivalents shall be paid with respect to unvested Stock Awards, including Stock Awards subject to Performance Goals. Dividends or Dividend Equivalents paid with respect to unvested Stock Awards may, in the discretion of the Committee, be accumulated and paid to the Participant at the time that such Stock Award vests. Dividends and/or Dividend Equivalents shall not be made part of any Options or SARs.

11. ***Option Exercise***. The Exercise Price shall be paid in full at the time of exercise in cash or, if permitted by the Committee and elected by the Participant, the Participant may purchase such shares by means of the Company withholding shares of Common Stock otherwise deliverable on exercise of the Award or tendering Common Stock valued at Fair Market Value on the date of exercise, or any combination thereof. The Committee, in its sole discretion, shall determine acceptable methods for Participants to tender Common Stock or other Awards. The Committee may provide for procedures to permit the exercise or purchase of such Awards by use of the proceeds to be received from the sale of Common Stock issuable pursuant to an Award (including cashless exercise procedures approved by the Committee involving a broker or dealer approved by the Committee). The Committee may adopt additional rules and procedures regarding the exercise of Options from time to time, provided that such rules and procedures are not inconsistent with the provisions of this Paragraph 11.

12. ***Taxes***. The Company shall have the right to deduct applicable taxes from any Award payment and withhold, at the time of delivery or vesting of cash or shares of Common Stock under this Plan, an appropriate amount of cash or number of shares of Common Stock or a combination thereof for payment of required withholding taxes or to take such other action as may be necessary in the opinion of the Company to satisfy all obligations for withholding of such taxes; *provided, however*, that the number of shares of Common Stock withheld for payment of required withholding taxes must equal no more than the required minimum withholding taxes (or such other rate that will not result in an adverse accounting consequence or cost). The Committee may also permit withholding to be satisfied by the transfer to the Company of shares of Common Stock theretofore owned by the holder of the Award with respect to which withholding is required. If shares of Common Stock are used to satisfy tax withholding, such shares shall be valued based on the Fair Market Value when the tax withholding is required to be made.

13. ***Amendment, Modification, Suspension or Termination***. The Board may amend, modify, suspend or terminate this Plan (and the Committee may amend an Award Agreement) for the purpose of meeting or addressing any changes in legal requirements or for any other purpose permitted by law, except that (1) no amendment or alteration that would materially adversely affect the rights of any Participant under any Award previously granted to such Participant shall be made without the consent of such Participant and (2) no amendment or alteration shall be effective prior to its approval by the stockholders of the Company to the extent stockholders approval is otherwise required by applicable legal requirements or the requirements of the securities exchange on which the Company's stock is listed, including any amendment that expands the types of Awards available under this Plan, materially increases the number of shares of Common Stock available for Awards under this Plan, materially expands the classes of persons eligible for Awards under this Plan, materially extends the term of this Plan, materially changes the method of determining the Exercise Price of Options, deletes or limits any provisions of this Plan that prohibit the repricing of Options or SARs.

14. ***Assignability***. Unless otherwise determined by the Committee (or the Board in the case of Director Awards) or expressly provided for in an Award Agreement, no Award or any other benefit under this Plan shall be assignable or otherwise transferable except (1) by will or the laws of descent and distribution or (2) pursuant to a domestic relations order issued by a court of competent jurisdiction that is not contrary to the terms and conditions of this Plan or applicable Award and in a form acceptable to the Committee. The Committee may prescribe and include in applicable Award Agreements other restrictions on transfer. Any attempted assignment of an Award or any other benefit under this Plan in violation of this Paragraph 14 shall be null and void. Notwithstanding the foregoing, no Award may be transferred for value or consideration.

15. ***Adjustments***.

(a) The existence of outstanding Awards shall not affect in any manner the right or power of the Company or its stockholders to make or authorize any or all adjustments, recapitalizations, reorganizations or other changes in the capital stock of the Company or its business or any merger or consolidation of the Company, or any issue of bonds, debentures, preferred or prior preference stock (whether or not such issue is prior to, on a parity with or junior to the Common Stock) or the dissolution or liquidation of the Company, or any sale or transfer of all or any part of its assets or business, or any other corporate act or proceeding of any kind, whether or not of a character similar to that of the acts or proceedings enumerated above.

(b) In the event of any subdivision or consolidation of outstanding shares of Common Stock, declaration of a dividend payable in shares of Common Stock or other stock split, then (1) the number of shares of Common Stock reserved under this Plan, (2) the number of shares of Common Stock covered by outstanding Awards in the form of Common Stock or units denominated in Common Stock, (3) the Exercise Price or other price in respect of such Awards, (4) the Stock-Based Award Limitations, and (5) the appropriate Fair Market Value and other price determinations for such Awards shall each be proportionately adjusted by the Committee as appropriate to reflect such transaction. In the event of any other recapitalization or capital reorganization of the Company, any consolidation or merger of the Company with another corporation or entity, the adoption by the Company of any plan of exchange affecting the Common Stock or any distribution to holders of Common Stock of securities or property (other than normal cash dividends or dividends payable in Common Stock), the Committee shall make appropriate adjustments to (i) the number and kind of shares of Common Stock covered by Awards in the form of Common Stock or units denominated in Common Stock, (ii) the Exercise Price or other price in respect of such Awards, (iii) the appropriate Fair Market Value and other price determinations for such Awards, and (iv) the Stock-Based Award Limitations to reflect such transaction; provided that such adjustments shall only be such as are necessary to maintain the proportionate interest of the holders of the Awards and preserve, without increasing, the value of such Awards.

(c) In the event of a corporate merger, consolidation, acquisition of property or stock, separation, reorganization or liquidation, the Committee may make such adjustments to Awards or other provisions for the disposition of Awards as it deems equitable, and shall be authorized, in its discretion, (1) to provide for the substitution of a new Award or other arrangement (which, if applicable, may be exercisable for such property or stock as the Committee determines) for an Award or the assumption of the Award, regardless of whether in a transaction to which Code Section 424(a) applies, (2) to provide, prior to the transaction, for the acceleration of the vesting and exercisability of, or lapse of restrictions with respect to, the Award and, if the transaction is a cash merger, provide for the termination of any portion of the Award that remains unexercised at the time of such transaction and provide Fair Market Value for any Award so terminated, or (3) to cancel any such Awards and to deliver to the Participants cash in an amount that the Committee shall determine in its sole discretion is equal to the Fair Market Value of such Awards on the date of such event.

(d) No adjustment or substitution pursuant to this Paragraph 15 shall be made in a manner that results in noncompliance with the requirements of Code Section 409A, to the extent applicable.

16. ***Restrictions***. No Common Stock or other form of payment shall be issued with respect to any Award unless the Company shall be satisfied based on the advice of its counsel that such issuance will be in compliance with applicable federal and state securities laws. Certificates evidencing shares of Common Stock delivered under this Plan (to the extent that such shares are so evidenced) may be subject to such stop transfer orders and other restrictions as the Committee may deem advisable under the rules, regulations and other requirements of the Securities and Exchange Commission, any securities exchange or transaction reporting system upon which the Common Stock is then listed or to which it is admitted for quotation and any applicable federal or state securities law. The Committee may cause a legend or legends to be placed upon such certificates (if any) to make appropriate reference to such restrictions.

17. ***Unfunded Plan***. This Plan is unfunded. Although bookkeeping accounts may be established with respect to Participants who are entitled to cash, Common Stock or rights thereto under this Plan, any such accounts shall be used merely as a bookkeeping convenience. The Company shall not be required to segregate any assets that may at any time be represented by cash, Common Stock or rights thereto, nor shall this Plan be construed as providing for such segregation, nor shall the Company, the Board or the Committee be deemed to be a trustee of any cash, Common Stock or rights thereto to be granted under this Plan. Any liability or obligation of the Company to any Participant with respect to an Award of cash, Common Stock or rights thereto under this Plan shall be based solely upon any contractual obligations that may be created by this Plan and any Award Agreement, and no such liability or obligation of the Company shall be deemed to be secured by any pledge or other encumbrance on any property of the Company. None of the Company, the Board or the Committee shall be required to give any security or bond for the performance of any obligation that may be created by this Plan. With respect to this Plan and any Awards granted hereunder, Participants are general and unsecured creditors of the Company and have no rights or claims except as otherwise provided in this Plan or any applicable Award Agreement.

18. ***Code Section 409A***.

(a) Awards made under this Plan are intended to comply with or be exempt from Code Section 409A, and ambiguous provisions hereof, if any, shall be construed and interpreted in a manner consistent with such intent. No payment, benefit or consideration shall be substituted for an Award if such action would result in the imposition of taxes under Code Section 409A. Notwithstanding anything in this Plan to the contrary, if any Plan provision or Award under this Plan would result in the imposition of an additional tax under Code Section 409A, that Plan provision or Award shall be reformed, to the extent permissible under Code Section 409A, to avoid imposition of the additional tax, and no such action shall be deemed to adversely affect the Participant's rights to an Award.

(b) Unless the Committee provides otherwise in an Award Agreement, each Restricted Stock Unit Award, Performance Unit Award or Cash Award (or portion thereof if the Award is subject to a vesting schedule) shall be settled no later than the 15th day of the third month after the end of the first calendar year in which the Award (or such portion thereof) is no longer subject to a "substantial risk of forfeiture" within the meaning of Code Section 409A. If the Committee determines that a Restricted Stock Unit Award, Performance Unit Award or Cash Award is intended to be subject to Code Section 409A, the applicable Award Agreement shall include terms that are designed to satisfy the requirements of Code Section 409A.

(c) If the Participant is identified by the Company as a "specified employee" within the meaning of Code Section 409A(a)(2)(B)(i) on the date on which the Participant has a "separation from service" (other than due to death) within the meaning of Treasury Regulation § 1.409A-1(h), any Award payable or settled on account of a separation from service that is deferred compensation subject to Code Section 409A shall be paid or settled on the earliest of (1) the first business day following the expiration of six months from the Participant's separation from service, (2) the date of the Participant's death, or (3) such earlier date as complies with the requirements of Code Section 409A.

19. ***Awards to Foreign Nationals and Employees Outside the United States***. The Committee may, without amending this Plan, (1) establish special rules applicable to Awards granted to Participants who are foreign nationals, are employed or otherwise providing services outside the United States, or both, including rules that differ from those set forth in this Plan, and (2) grant Awards to such Participants in accordance with those rules.

20. ***Governing Law***. This Plan and all determinations made and actions taken pursuant hereto, to the extent not otherwise governed by mandatory provisions of the Code or the securities laws of the United States, shall be governed by and construed in accordance with the laws of the State of Delaware.

21. ***Right to Continued Service or Employment***. Nothing in this Plan or an Award Agreement shall interfere with or limit in any way the right of the Company or any of its Subsidiaries to terminate any Participant's employment or other service relationship with the Company or its Subsidiaries at any time, nor confer upon any Participant any right to continue in the capacity in which he is employed or otherwise serves the Company or its Subsidiaries.

22. ***Clawback Right***. Notwithstanding any other provisions in this Plan, any Award shall be subject to recovery or clawback by the Company pursuant to any applicable law, regulation, or stock exchange listing requirement, and under any clawback policy adopted by the Company whether before or after the date of grant of the Award.

23. ***Usage***. Words used in this Plan in the singular shall include the plural and in the plural the singular, and the gender of words used shall be construed to include whichever may be appropriate under any particular circumstances of the masculine, feminine or neuter genders.

24. ***Headings***. The headings in this Plan are inserted for convenience of reference only and shall not affect the meaning or interpretation of this Plan.

25. ***Effectiveness***. This Plan was initially approved by the Company's stockholders at the annual meeting on July 29, 2013 and its amendment and restatement was approved by the Company's stockholders at the annual meeting on May 4, 2016. This Plan is effective as of the Effective Date and shall continue in effect for a term of 10 years commencing on the Effective Date, unless earlier terminated by action of the Board.

(This page has been left blank intentionally.)

ATTACHMENT A

JONES ENERGY, INC. 2013 OMNIBUS INCENTIVE PLAN

DEFINITION OF CHANGE IN CONTROL

Except as otherwise provided in an Award Agreement, for purposes of this Plan, a "*Change in Control*" shall be deemed to have occurred upon the occurrence of any of the following after the date hereof:

(a) ***40% Ownership Change:*** Any Person, the Company, or an Affiliate, other than the Jones Family Entities or Metalmark Capital, makes an acquisition of Outstanding Voting Stock and is, immediately thereafter, the beneficial owner of 40% or more of the then Outstanding Voting Stock, unless such acquisition is made directly from the Company in a transaction approved by a majority of the Incumbent Directors; or any group is formed that is the beneficial owner of 40% or more of the Outstanding Voting Stock; or

(b) ***Major Mergers and Acquisitions:*** Consummation of a Business Combination unless, immediately following such Business Combination, (i) all or substantially all of the individuals and entities that were the beneficial owners of the Outstanding Voting Stock immediately before such Business Combination beneficially own, directly or indirectly, more than 50% of the then outstanding shares of voting stock of the parent corporation resulting from such Business Combination in substantially the same relative proportions as their ownership, immediately before such Business Combination, of the Outstanding Voting Stock, (ii) no Person (other than any corporation resulting from such Business Combination or Jones Family Entities or Metalmark Capital) beneficially owns, directly or indirectly, 40% or more of the then outstanding shares of voting stock of the parent corporation resulting from such Business Combination and (iii) a majority of the members of the board of directors of the parent corporation resulting from such Business Combination were Incumbent Directors of the Company immediately before consummation of such Business Combination; or

(c) ***Major Asset Dispositions:*** Consummation of a Major Asset Disposition unless, immediately following such Major Asset Disposition, (i) individuals and entities that were beneficial owners of the Outstanding Voting Stock immediately before such Major Asset Disposition beneficially own, directly or indirectly, more than 70% of the then outstanding shares of voting stock of the Company (if it continues to exist) and of the entity that acquires the largest portion of such assets (or the entity, if any, that owns a majority of the outstanding voting stock of such acquiring entity) and (ii) a majority of the members of the Board (if it continues to exist) and of the entity that acquires the largest portion of such assets (or the entity, if any, that owns a majority of the outstanding voting stock of such acquiring entity) were Incumbent Directors of the Company immediately before consummation of such Major Asset Disposition.

Anything in this definition to the contrary notwithstanding, no Change in Control shall be deemed to have occurred unless such event constitutes an event specified in Code Section 409A(a)(2)(A)(v) and the Treasury Regulations promulgated thereunder.

For purposes of the definition of a "Change in Control",

(1) "*Affiliate*" means an Affiliate within the meaning of Rule 12b-2 promulgated under Section 12 of the Exchange Act.

(2) "*beneficial owner*" is used as it is defined for purposes of Rule 13d-3 under the Exchange Act;

(3) "*Business Combination*" means

(x) a merger or consolidation involving the Company or its stock or

(y) an acquisition by the Company, directly or through one or more subsidiaries, of another entity or its stock or assets;

(4) "*election contest*" is used as it is defined for purposes of Rule 14a-11 under the Exchange Act;

(5) "*group*" is used as it is defined for purposes of Section 13(d)(3) of the Exchange Act;

(6) "*Incumbent Director*" means a director of the Company (x) who was a director of the Company on the effective date of the Plan or (y) who becomes a director after such date and whose election, or nomination for election by the Company's stockholders, was approved by a vote of a majority of the Incumbent Directors at the time of such election or nomination, except that any such director will not be deemed an Incumbent Director if his or her initial assumption of office occurs as a result of an actual or threatened election contest or other actual or threatened solicitation of proxies by or on behalf of a Person other than the Board;

(7) "*Jones Family Entities*" means entities directly or indirectly controlled by Jonny Jones, Chairman and Chief Executive Officer of the Company, and/or his immediate family.

(8) "*Major Asset Disposition*" means the sale or other disposition in one transaction or a series of related transactions of 80% or more of the assets of the Company and its subsidiaries on a consolidated basis; and any specified percentage or portion of the assets of the Company will be based on fair market value, as determined by a majority of the Incumbent Directors.

(9) "*Metalmark Capital*" means Metalmark Capital Partners (C) II, L.P. and its affiliated investment funds.

(10) "*Outstanding Voting Stock*" means outstanding voting securities of the Company entitled to vote generally in the election of directors; and any specified percentage or portion of the Outstanding Voting Stock (or of other voting stock) is determined based on the combined voting power of such securities;

(11) "*parent corporation resulting from a Business Combination*" means the Company if its stock is not acquired or converted in the Business Combination and otherwise means the entity which as a result of such Business Combination owns the Company or all or substantially all the Company's assets either directly or through one or more subsidiaries; and

(12) "*Person*" means an individual, entity or group.

JONES ENERGY, INC.
SHORT TERM INCENTIVE PLAN
(Amended and Restated as of May 4, 2016)

1. ***Purpose***: The purpose of the Jones Energy, Inc. Short Term Incentive Plan (the "***Plan***") is to encourage a high level of corporate performance through the establishment of predetermined corporate, Subsidiary or business unit and/or individual goals, the attainment of which will require a high degree of competence and diligence on the part of those Employees (including officers) of Jones Energy, Inc., a Delaware corporation (the "***Company***") or of its participating Subsidiaries selected to participate in the Plan, and which will be beneficial to the owners and customers of the Company.

2. ***Definitions***: Unless the context otherwise clearly requires, the following definitions are applicable to the Plan:

Award: An incentive compensation award granted to a Participant with respect to a particular Plan Year pursuant to any applicable terms, conditions and limitations as the Committee may establish in order to fulfill the objectives of the Plan.

Board: The Board of Directors of the Company.

Code: The Internal Revenue Code of 1986, as amended.

Committee: The Compensation Committee of the Board or any successor committee of the Board designated by the Board consisting of at least two directors.

Company: Jones Energy, Inc. or any successor thereto.

Compensation: Compensation or eligible earnings during the year means the actual base salary paid to a salaried exempt Participant during the Plan Year, including vacation, holiday and sick time. Compensation or eligible earnings during the year means the actual gross wages paid to a hourly or salaried non-exempt Participant during the Plan Year, including vacation, holiday and sick time. Eligible earnings exclude all special payments, bonuses, allowances, reimbursements and payments in lieu of overtime, but include overtime pay in a manner consistent with the requirements of applicable labor law.

Employee: An employee of the Company or any of its Subsidiaries who is a regular full or part-time employee and who regularly works at least 20 hours per week.

Employer: The Company and each Subsidiary which is designated by the Committee as an Employer under this Plan.

Exchange Act: The Securities Exchange Act of 1934, as amended from time to time.

Participant: An Employee who is selected to participate in the Plan.

Payment Date: The date an Award shall be paid as provided in Section 8(b) of the Plan.

Performance Award: An Award made to a Participant pursuant to this Plan that is subject to the attainment of one or more Performance Goals.

Performance Goals: The performance objectives of the Company, its Subsidiaries or its business units and/or individual Participants established for the purpose of determining the level of Awards, if any, earned during a Plan Year.

Plan: This Jones Energy, Inc. Short Term Incentive Plan, as amended and restated as of May 4, 2016 and as thereafter amended from time to time.

Plan Year: The calendar year.

Subsidiary: A subsidiary corporation with respect to the Company as defined in Section 424(f) of the Code.

A pronoun or adjective in the masculine gender includes the feminine gender, and the singular includes the plural, unless the context clearly indicates otherwise.

3. ***Participation***: The Committee shall select the Employees who will be Participants for each Plan Year. No Employee shall at any time have the right (a) to be selected as a Participant in the Plan for any Plan Year, (b) if so selected, to be entitled to an Award, or (c) if selected as a Participant in one Plan Year, to be selected as a Participant in any subsequent Plan Year. The terms and conditions under which a Participant may participate in the Plan shall be determined by the Committee in its sole discretion.

4. ***Eligibility***: Except as otherwise determined by the Committee, only Employees who (a) are employed on the last day of the Plan Year and (b) are employed on the Payment Date are eligible for the payment of an Award under the Plan.

5. ***Plan Administration***: The Plan shall be administered by the Committee. All decisions of the Committee shall be binding and conclusive on the Participants. The Committee, on behalf of the Participants, shall enforce this Plan in accordance with its terms and shall have all powers necessary for the accomplishment of that purpose, including, but not by way of limitation, the following powers:

(a) To select the Participants;

(b) To interpret, construe, approve and adjust all terms, provisions, conditions and limitations of this Plan;

(c) To decide any questions arising as to the interpretation or application of any provision of the Plan;

(d) To prescribe forms and procedures to be followed by Employees for participation in the Plan, or for other occurrences in the administration of the Plan;

(e) To establish the terms and conditions of any Agreement under which an Award may be earned and paid; and

(f) In addition to all other powers granted herein, the Committee shall make and enforce such rules and regulations for the administration of the Plan as are not inconsistent with the terms set forth herein.

No member of the Committee or officer of the Company to whom the Committee has delegated authority in accordance with the provisions of Section 6 of this Plan shall be liable for anything done or omitted to be done by him, by any member of the Committee or by any officer of the Company in connection with the performance of any duties under this Plan, except for his own willful misconduct or as expressly provided by statute.

6. ***Delegation of Authority***: The Committee may delegate any of its authority (i) to select Participants, (ii) grant Awards and (iii) determine the value of Awards granted to Participants to any other committee of the Board or to the Company's Chief Executive Officer, provided such delegation is made in writing and specifically sets forth such delegated authority. The foregoing notwithstanding, the Committee may not delegate its authority with respect to Awards granted to a Participant who is subject to Code Section 162(m). The officers of the Company, for and on behalf of the Company, may engage or authorize the engagement of a third party administrator to carry out administrative functions under this Plan. Any such delegation hereunder shall only be made to the extent permitted by applicable law.

7. ***Awards***:

(a) *General.* The Committee shall determine the terms and conditions of Awards to be made under this Plan and shall designate from time to time the individuals who are to be the recipients of Awards. Awards may also be made in combination or in tandem with, in replacement of, or as alternative to, grants or rights under this Plan or any other employee plan of the Company or any of its Subsidiaries, including the plan of any acquired entity. An Award may provide for the grant or issuance of additional, replacement or alternative Awards upon the occurrence of specified events. All or part of an Award may be subject to conditions established by the Committee, which may include, but are not limited to, continuous service with the Company and its Subsidiaries, achievement of specific individual and/or business objectives, increases in specified indices, attainment of specified growth rates and other comparable measurements of performance. Unless specified otherwise by the Committee, the amount payable pursuant to an Award shall be based on a percentage of the Participant's Compensation.

(b) *Performance Awards.* An Award may be in the form of a Performance Award. A Performance Award shall be paid, vested or otherwise deliverable solely on account of the attainment of one or more pre-established, objective Performance Goals, which together with any approved exclusions (as set forth in the below paragraph), shall be established by the Committee (x) no later than 90 days after the commencement of such period of service to which the Performance Goal relates and (y) prior to the lapse of 25% of such period of service (as scheduled in good faith at the time the goal is established), and in any event while the outcome is substantially uncertain. A Performance Goal is objective if a third party having knowledge of the relevant facts could determine whether the goal is met. Such a Performance Goal may be based on one or more business criteria that apply to the individual, one or more business units of the Company, or the Company as a whole. Any Performance Goals that are financial metrics, may be determined in accordance with U.S. Generally Accepted Accounting Principles ("***GAAP***"), in accordance with accounting principles established by the International Accounting Standards Board ("***IASB Principles***"), or may be adjusted when established to include or exclude any items otherwise includable or excludable under GAAP or under IASB Principles. Performance Goals shall be based upon targets established by the Committee with respect to one or more of the following financial or operational factors, as applied to the Company or a business unit, as applicable: (1) earnings per share; (2) production; (3) increase in cash flow; (4) increase in cash flow from operations; (5) increase in cash flow return; (6) return on net assets; (7) return on assets; (8) return on investment; (9) return on capital; (10) return on equity; (11) economic value added; (12) operating margin; (13) increase in production; (14) net income; (15) net income per share; (16) pretax earnings; (17) pretax earnings before interest, depreciation and amortization; (18) pretax earnings before interest, depreciation, amortization and exploration; (19) pretax operating earnings after interest expense and before incentives, service fees, and infrequent or unusual items; (20) total stockholder return; (21) debt reduction; (22) finding and development costs; (23) operating income; (24) internal rate of return; (25) safety; (26) operating expenses; (27) general and administrative expenses; (28) capital efficiency; (29) reserve replacement cost; and (30) any of the above goals determined on an absolute or relative basis or as compared to the performance of a published or special index deemed applicable by the Committee including, but not limited to, the Standard & Poor's 500 Stock Index, Russell 2000 or a group of comparable companies.

At the time it establishes the Performance Goals, the Committee may provide for the impact of an event or occurrence which the Committee determines should appropriately be excluded or included, including (a) asset write-downs, (b) litigation or claim judgments or settlements, (c) the effect of changes in tax laws, accounting principles, or other laws or provisions affecting reported results, (d) any reorganization and restructuring programs, (e) infrequent and unusual items as defined by the Company's auditors and/or in management's discussion and analysis of financial condition and results of operations appearing in the Company's annual report to stockholders for the applicable year, (f) acquisitions or divestitures, (g) foreign exchange gains and losses and (h) settlement of hedging activities.

Prior to the payment of any compensation based on the achievement of Performance Goals, the Committee must certify in writing that applicable Performance Goals and any of the material terms thereof were, in fact, satisfied. The Committee, in its sole discretion, may decrease the amount payable pursuant to a Performance Award, but in no event shall the Committee have discretion to increase the amount payable to a Participant who is a "Covered Employee" as defined under Code Section 162(m) and accompanying guidance issued thereunder pursuant to a Performance Award in a manner inconsistent with the requirements for qualified performance-based compensation under Code Section 162(m). However, the Committee may increase the amount of a Performance Award to any Participant who is not a Covered Employee. For purposes of clarity, the Committee may exercise the discretion provided for by the foregoing in a non-uniform manner among Participants.

In interpreting Plan provisions applicable to Performance Goals and Performance Awards, it is the intent of the Plan to conform with the standards of Code Section 162(m) applicable to qualified performance-based compensation, and the Committee in establishing such Performance Goals and interpreting the Plan shall be guided by such provisions (including, for the avoidance of doubt, any transition relief afforded thereunder). Subject to the foregoing provisions, the terms, conditions and limitations applicable to any Performance Awards pursuant to this Plan shall be determined by the Committee. No Participant may be granted Performance Awards which will result in the payment of more than $5,000,000 per Plan Year. If an Award is cancelled, the cancelled Award shall continue to be counted toward the applicable limitation in this Section, to the extent required by Code Section 162(m).

8. ***Payment of Awards***: The Committee has sole and absolute authority and discretion to determine whether an Award shall be paid under this Plan and if so such payment will be made in accordance with the following:

(a) *Form of Payment:* In the discretion of the Committee, payment of Awards shall be made in (i) a lump sum cash payment, (ii) Company common stock available under the Company's Long Term Incentive Plan or other equity plan or (iii) a combination of (i) and (ii). Award payments may be subject to such restrictions as the Committee shall determine.

(b) *Date of Payment:* Payment of any Awards for a Plan Year ("***Award Plan Year***") shall be made as soon as practicable after the close of the Award Plan Year (as determined by the Committee), but in no event later than March 15th of the Plan Year immediately following the close of the Award Plan Year ("***Payment Date***").

9. ***Assignability***: Unless otherwise determined by the Committee and provided in the Agreement, no Award or any other benefit under this Plan shall be assignable or otherwise transferable, except by will or the laws of descent and distribution. Any attempted assignment of an Award or any other benefit under this Plan in violation of this Section 9 shall be null and void.

10. ***Tax Withholding***: The Company shall have the right to withhold applicable taxes from any Award payment and to take such other action as may be necessary in the opinion of the Company to satisfy all obligations for withholding of such taxes.

11. ***Finality of Determinations***: Any determination by the Committee in carrying out or administering this Plan shall be final and binding for all purposes and upon all interested persons and their heirs, successors, and personal representatives.

12. ***Employee Rights Under the Plan***: No Employee or other person shall have any claim or right to be granted an Award under this Plan. Neither the Plan nor any action taken thereunder shall be construed as giving an Employee any right to be retained in the employ of the Company or an Employer. No Participant shall have any lien on any assets of the Company or an Employer by reason of any Award made under this Plan.

13. ***Amendment, Modification, Suspension or Termination***: The Board may amend, modify, suspend or terminate this Plan for the purpose of meeting or addressing any changes in legal requirements or for any other purpose permitted by law, except that (a) no amendment or alteration that would materially and adversely affect the rights of any Participant under any Award previously granted to such Participant shall be made without the consent of such Participant and (b) no amendment or alteration shall be effective prior to its approval by the stockholders of the Company; provided, however, that clause (b) shall only apply if, and to the extent, such approval is required by applicable legal requirements.

14. ***Governing Law***: This Plan and all determinations made and actions taken pursuant hereto, shall be governed by and construed in accordance with the laws of the State of Delaware.

15. ***Effective Date***: The Plan is effective as of July 29, 2013 and is amended and restated effective as of May 4, 2016.

16. ***Exclusion from Section 409A***: This Plan is intended to provide "short-term deferrals" as described in Treasury Regulation § 1.409A-1(b)(4) under Section 409A of the Code (or successor guidance thereto), and not to be a "nonqualified deferred compensation plan" for purposes of Section 409A of the Code. The Plan shall be administrated and interpreted consistent with that intent.

17. ***Clawback Right***: Notwithstanding any other provisions in this Plan, any Award shall be subject to recovery or clawback by the Company pursuant to any applicable law, regulation, or stock exchange listing requirement, and under any clawback policy adopted by the Company whether before or after the date of grant of the Award.

18. ***Unfunded Status of Plan***: The Company shall not have any obligation to establish any separate fund or trust or other segregation of assets to provide for payments under the Plan. To the extent any person acquires any rights to receive payments hereunder from the Company, such rights shall be no greater than those of an unsecured creditor.

(This page has been left blank intentionally.)

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, 2015

☐ **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	New York Stock Exchange

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 and posted on its corporate website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ 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" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

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

The aggregate market value of the voting and non-voting common stock held by non-affiliates of the registrant computed as of June 30, 2015 (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 on the New York Stock Exchange was $272.4 million.

There were 30,550,907 and 31,273,130 shares of the registrant's Class A and Class B common stock, respectively, outstanding on February 29, 2016.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive proxy statement for the 2016 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.

JONES ENERGY, INC.
TABLE OF CONTENTS

PART 1
Item 1. Business . . . 3
Item 1A. Risk Factors . . . 30
Item 1B. Unresolved Staff Comments . . . 55
Item 2. Properties . . . 55
Item 3. Legal Proceedings . . . 55
Item 4. Mine Safety Disclosures . . . 55
PART II
Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities . . . 56
Item 6. Selected Financial Data . . . 58
Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations 63
Item 7A. Quantitative and Qualitative Disclosures about Market Risk . . . 84
Item 8. Financial Statements and Supplementary Data . . . 85
Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure 85
Item 9A. Controls and Procedures . . . 85
Item 9B. Other Information . . . 87
PART III
Item 10. Directors, Executive Officers and Corporate Governance . . . 87
Item 11. Executive Compensation . . . 87
Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters . . . 88
Item 13. Certain Relationships and Related Transactions, and Director Independence . . . 88
Item 14. Principal Accounting Fees and Services . . . 88
PART IV
Exhibit Index . . . 89
Signatures . . . 93
Financial Statements
Balance Sheets . . . F-3
Statements of Operations . . . F-4
Statement of Changes in Stockholders' / Members' Equity . . . F-5
Statements of Cash Flows . . . F-6
Notes to the Consolidated Financial Statements . . . F-7

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," "anticipate," "intend," "estimate," "expect," "project" and similar expressions are intended to identify forward-looking statements, although 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;
- drilling and completion of wells including our identified drilling locations;
- cash flows and liquidity;
- financial strategy, budget, 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 2016 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;
- 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;
- general economic conditions, including the levels of supply and demand for oil, natural gas and NGLs, and the commodity price environment;
- 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;
- weather, including its impact on oil and natural gas demand and weather-related delays on operations;
- technology; and
- plans, objectives, expectations and intentions contained in this report that are not historical.

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.

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. 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 incorporated pursuant to the laws of the State of Delaware in March 2013 to become a holding company for an investment in Jones Energy Holdings, LLC ("JEH"). As the sole managing member of JEH, Jones Energy, Inc. is responsible for all operational, management and administrative decisions relating to JEH's business and consolidates the financial results of JEH and its subsidiaries.

Jones Energy, Inc.'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 pre-IPO owners of JEH and can be exchanged (together with a corresponding number of JEH Units) for shares of Class A common stock on a one-for-one basis, subject to customary conversion rate adjustments for stock splits, stock dividends and reclassifications and other similar transactions. Jones Energy, Inc.'s Class A common stock has been listed on the New York Stock Exchange ("NYSE") under the symbol "JONE" since July 2013.

Overview

We are an independent oil and gas company engaged in the exploration, development, production and acquisition of oil and natural gas properties in the mid-continent United States, spanning areas of Texas and Oklahoma. Our Chairman and CEO, Jonny Jones, founded our predecessor company in 1988 in continuation of his family's long history in the oil and gas business, which dates back to the 1920's. We have grown rapidly by leveraging our focus on low cost drilling and completion methods and our horizontal drilling expertise to develop our inventory and execute several strategic acquisitions. We have accumulated extensive knowledge and experience in developing the Anadarko and Arkoma basins, having concentrated our operations in the Anadarko basin for over 25 years and applied our knowledge to the Arkoma basin since 2011. We have drilled 827 total wells, including over 650 horizontal wells, since our formation and delivered compelling rates of return over various commodity price cycles. Our operations are focused on horizontal drilling and completions within two distinct basins in the Texas Panhandle and Oklahoma:

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

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

The Anadarko and Arkoma basins are among the most prolific and largest onshore producing 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 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 and acquisition opportunities and to which we can apply our technical experience and operational excellence to increase proved reserves and production to deliver attractive economic rates of return. Our goal is to build value through a disciplined balance between developing our current inventory of 2,103 gross identified drilling locations, identifying new opportunities within our existing asset base, and actively pursuing organic leasing, strategic acquisitions and joint development agreements. In all of our joint development agreements, we control the drilling and completion of a well, which is the phase during which we can most effectively leverage our operational expertise and cost discipline. Following completion, we may in some cases turn over operatorship to a partner during the production phase of a well. We believe the ceding to us of drilling and completion operatorship in our areas of operation by several large oil and gas companies, including ExxonMobil and BP, reflects their acknowledgement of our low-cost, safe and efficient operations.

As of December 31, 2015, our total estimated proved reserves were 101.7 MMBoe, of which 58% were classified as proved developed reserves. Approximately 25% of our total estimated proved reserves as of December 31, 2015 consisted of oil, 32% consisted of NGLs, and 43% consisted of natural gas. As of December 31, 2015, our properties included 1,016 gross producing wells. For the three years ended December 31, 2015, we drilled 294 wells, substantially all of which we drilled as operator. The following table presents summary reserve, acreage and production data for each of our core operating areas:

	As of December 31, 2015				Year Ended December 31, 2015	
	Estimated Net Proved Reserves		Acreage		Average Daily Net Production	
	MMBoe	% Oil and NGLs	Gross Acreage	Net Acreage	MBoe/d	% Oil and NGLs
Cleveland	80.6	63%	181,353	117,700	18.4	64%
Woodford	16.3	32%	12,383	4,418	3.6	31%
Other	4.8	43%	34,488	15,259	3.1	40%
All properties	101.7	57%	228,224	137,377	25.1	57%

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

	As of December 31, 2015			
	Producing Wells		Identified Drilling Locations(1)	
	Gross	Net	Gross	Net
Cleveland	573	410	711	455
Woodford	152	59	277	45
Other	291	81	1,115	473
All properties	1,016	550	2,103	973

(1) Our total identified drilling locations include 412 gross locations associated with proved undeveloped reserves as of December 31, 2015. 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 2015 capital expenditures totaled $200.1 million (excluding the impact of asset retirement costs), of which $173.2 million was utilized to drill and complete operated wells. The Company has established an initial capital budget of $25 million for 2016, a decrease of approximately 87.9% from the $206.4 million incurred for 2015, with the majority of the initial 2016 budget dedicated to capital well workovers and field optimization activities. We will continue to monitor market conditions and

may spend additional funds for a variety of opportunities which may include redeploying rigs to resume drilling activities or leasing additional acreage. At present, the Company continues to negotiate with vendors regarding service costs and does not plan on resuming its drilling program until well costs create acceptable rates of return at the available commodity prices. Please see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources." Assuming current market conditions, we believe we will be able to fund all of our 2016 budgeted capital expenditures with our cash flow from operations. Furthermore, we expect to develop all drilling locations classified as proved undeveloped reserves in the year-end reserve report within five years. 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.

Business Strategies

Our goal is to increase shareholder value by managing our capital expenditures and level of activity to maximize returns through commodity price cycles while also evaluating and executing opportunities for growth of reserves, production, and cash flow through potential partnerships, acquisitions, and leasing opportunities. We seek to achieve this goal by executing a combination of the following strategies:

Maintain the Lowest Cost Structure in the Plays Where We Operate.

Decades of experience in the Midcontinent and emphasis on operational execution and cost control have allowed us to drill and complete wells at significantly lower cost than most other operators and, as a result, to realize compelling economic returns. In the Cleveland, for example, from 2005 to 2014 we reduced our well spud-to-rig release time, which directly affects drilling costs, from 30 days to 23 days, and in 2015 we further reduced that metric to 17 days, down six days from 2014. During that same timeframe, we have more than doubled the lateral lengths of wells we drilled, which directly affects production, from approximately 2,000 feet to approximately 4,500 feet per well. We will continue to apply this expertise while also leveraging our leading position in our focus areas to obtain the best possible pricing from service providers which we expect will further reduce capital costs and ultimately enhance returns. Our cost structure is particularly important in periods of low commodity prices and may give us an advantage over other operators as we compete for acquisitions, leases, and strategic partnerships.

Develop Our Multi-Year Inventory.

We intend to add production and reserves through the development of our existing drilling inventory, which we believe to be repeatable and low-risk. The Company has a long history in the Midcontinent, having drilled 827 wells in the area since 1988. We believe our historical drilling experience, together with the results of substantial industry activity within our operating areas, reduces the risk and uncertainty associated with drilling horizontal wells in these areas. As of December 31, 2015, we have identified 2,103 gross drilling locations, which gives us many years of development drilling based on our current development plan.

Opportunistically Grow Through Exploration, Acquisitions and Strategic Partnerships.

As a complement to our development program, we look to execute acquisitions, leases and partnerships where our operating experience can be leveraged. Given the Company's ability to decrease costs and ramp up drilling activity, we seek opportunities that have less PDP reserves and a large number of high-quality drilling locations. Since 2009, we have successfully executed four significant acquisitions and several bolt-on acquisitions in our operating areas, for an aggregate purchase price of approximately $900 million.

We also continue to seek new leasing opportunities to expand our acreage position and complement our existing drilling inventory, as we believe that targeted organic leasing around our existing acreage provides the ability for greater returns due to cost and operating synergies in overlapping areas of operation. In calendar year 2015, we leased over 10,000 net acres.

Joint development opportunities complement our acquisition strategy by providing a capital efficient and risk-lowering approach to acquiring drilling opportunities. These agreements give us control over the drilling and completion phase of the well, where we can add value by applying our low cost structure. In this regard, we have a history of developed relationships with several large exploration and production companies such as BP, ConocoPhillips, Devon Energy, ExxonMobil, Linn Energy, Vanguard Natural Resources and Samson Resources, in which they have farmed out portions of their basin operations to us. We have drilled over 310 wells in connection with these types of agreements, over 170 of which have been drilled in connection with an active 15-year farm-out and development agreement with ExxonMobil.

Exploit Upside Within Our Existing Assets.

The stacked reservoirs within our asset base provide exposure to additional upside potential in several emerging resource plays. We have begun assessing the potential of both the Tonkawa and Marmaton formations in the Anadarko Basin. We expect to engage in additional development activity within these plays as commodity prices improve. Based upon our recent assessment, we believe that we have approximately 752 potential drilling locations in the Tonkawa and Marmaton formations that provide us with additional resource potential. Further, our current leasehold position provides longer term potential exposure to other prospective formations found in the Anadarko basin, including the Douglas, Cottage Grove, Cherokee Shale, Atoka Shale, and the Upper, Middle and Lower Morrow formations. In addition, we continue to apply our proven geoscience expertise in the search for new exploration opportunities in the greater Midcontinent region.

Maintain Operational Control.

We operated substantially all of the wells that we drilled and completed during 2015, allowing us to effectively manage the timing and levels of our development spending, overall well costs and operating expenses. In addition, we expect to operate the drilling and completion phase on approximately 72% of our 2,103 gross identified drilling locations. With over 80% of our acreage held by existing production, we also will not be required to expend significant capital to hold acreage in our portfolio. We believe that continuing to exercise a high degree of control over our acreage position will provide us with flexibility to manage our drilling program and optimize our returns and profitability.

Focus on Well-Level Returns.

Our management and technical teams are focused on maximizing well-level returns, which we believe drives shareholder value. In addition to our focus on costs and optimizing drilling and completion techniques, our team maximizes returns by allocating capital to areas with the highest rates of return based on commodity mix. Our drilling inventory comprises oil, natural gas and NGLs, which enables us to adjust our development approach based on prevailing commodity prices. In light of current commodity prices, we will continue to focus our drilling activity, if any, on locations which present the best commodity mix coupled with the most operational efficiency from a development program standpoint. In addition, we expect that continuing to operate the substantial majority of our drilling locations will allow us to reallocate our capital and resources opportunistically in response to

market conditions. Our disciplined focus on well-level returns in allocating our capital and resources has been a key component of our ability to deliver successful results through various commodity price cycles.

Competitive Strengths

We possess a number of competitive strengths that we believe will allow us to successfully execute our business strategy:

Geographic Focus in the Prolific U.S. Midcontinent.

Our operations are focused in the Midcontinent region, targeting liquids- rich opportunities in the Anadarko and Arkoma basins of Texas and Oklahoma. We generally focus on formations characterized by oil and liquids-rich natural gas content, extensive production histories, long-lived reserves, high drilling success rates, and attractive initial production rates. Furthermore, our areas of operation are proximate to well-developed natural gas and liquids midstream infrastructure and oilfield services providers, which we believe reduces the risk of production delays and facilitates adequate takeaway capacity.

Multi-Year Drilling Inventory in Existing and Emerging Resource Plays.

Our drilling inventory consists of approximately 2,103 gross identified drilling locations in the Anadarko and Arkoma basins, and our development plans target locations that we believe are low-cost, provide attractive economics, present low risk, and support a relatively predictable production profile. As of December 31, 2015, we had identified 711 gross drilling locations in the Cleveland play and 277 gross drilling locations in the Arkoma Woodford shale formation. Our concentrated leasehold position has been delineated largely through drilling on our Cleveland leasehold, which we expanded substantially through our Chalker and Sabine acquisitions and more recently through our leasing efforts. We have also expanded, in prior years, through joint development agreements with large independent producers and major oil and gas companies in the Cleveland and Woodford formations. Furthermore, we have identified additional locations in several emerging resource plays that we intend to explore and develop in the coming years, including 279 gross locations in the Tonkawa formation and 473 gross locations in the Marmaton formation.

Extensive Operational Expertise and Low-Cost Operating Structure.

Drilling horizontal wells has been our primary approach to field development since 1998. Having drilled over 650 horizontal wells in nine formations in our areas of operation since 1996, we have established systematic protocols that we believe provide repeatable results. We also have established relationships with oilfield services providers, allowing for continued cost efficiencies. As an example, we have consistently drilled horizontal Cleveland wells at a meaningfully lower cost than most of our competition in the same area. Through our focus on drilling, completion and operational efficiencies, we are able to effectively control costs and deliver attractive rates of return and profitability.

Strong Financial Position and Conservative Policies.

We are committed to maintaining a conservative financial profile in order to preserve operational flexibility and financial stability. We believe that our operating cash flow, together with projected availability under our senior secured revolving credit facility, provide us with the financial flexibility to pursue acquisitions, joint development agreements and organic leasing opportunities. In addition, we have historically hedged a significant amount of our production from oil, gas and NGLs. For the three years ended December 31, 2015, approximately 79% of our total production was protected by commodity hedges. Our hedge position is reviewed monthly to evaluate the impact of new wells coming online and changes to our development program. We intend to continue to actively hedge our future production in order to reduce the impact of commodity price volatility on our cash flows and secure our rates of return for up to five years. As of December 31, 2015, the market value of our existing hedges was approximately $217.5 million.

High Caliber Management Team with Deep Operating Experience and a Proven Track Record.

Our top five executives average more than 28 years of industry experience and have worked together developing assets for many years, resulting in a high degree of continuity. We have assembled a strong technical staff of geoscientists, field operations managers and engineers with significant experience drilling horizontal wells and with fracture stimulation of unconventional formations, which has resulted in a successful track record of reserve and production growth. In addition, our management team has extensive expertise and operational experience in the oil and natural gas industry with a proven track record of successfully negotiating, executing and integrating acquisitions. Members of our management team have previously held positions with both major and large independent oil and natural gas companies, including ExxonMobil, BP, Shell, Southwestern Energy, Marathon and Standard Oil.

Alignment of Management Team.

Our predecessor company was founded in 1988 by our CEO, Jonny Jones, in continuation of his family's history in the oil and gas business, which dates back to the 1920's. Jones family members and our management team controlled approximately 21.8% of our combined voting power and economic interest as of December 31, 2015. We believe the equity interests of our officers and directors align their interests and provide substantial incentive to grow the value of our business.

Recent Developments

See Note 15, "Subsequent Events," in the Notes to Consolidated Financial Statements for discussion of recent developments.

Our Operations

Our Areas 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 and Arkoma basins in Texas and Oklahoma. 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."

Anadarko Basin

Approximately 84% of our estimated proved reserves as of December 31, 2015 and approximately 82% of our average daily net production for the year ended December 31, 2015 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 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 12,000 feet. We drilled 51 gross (47 net) wells as

operator in the Anadarko basin in 2015. Our operations in the Anadarko basin are primarily focused on the Cleveland formation where we have 573 producing wells. We also have acreage in the Tonkawa, Marmaton, Granite Wash, and various Pennsylvanian-age shale formations located in the eastern portion of the Texas Panhandle and western Oklahoma.

Producing Formations. Our production in the Anadarko basin is currently derived primarily from the following formations, where we have 823 gross (483 net) producing wells and where we have identified 1,826 gross (928 net) drilling locations as of December 31, 2015, of which 357 have proved undeveloped reserves attributed to them as of December 31, 2015. See "Drilling Locations" for more information regarding the processes and criteria through which these drilling locations were identified.

- ***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, 2015, we operated 573 gross (410 net) wells producing from the Cleveland formation with an average working interest of 72%. Our Cleveland properties contained 80.6 MMBoe of estimated net proved reserves as of December 31, 2015, 63% of which are oil and NGLs, and generated an average daily net production of 18.4 MBoe/d for the year ended December 31, 2015. We have identified 711 gross (455 net) drilling locations in the Cleveland formation as of December 31, 2015. Of these 711 locations, 307 locations (43%) have proved undeveloped reserves attributed to them as of December 31, 2015.

- ***Tonkawa Formation.*** As of December 31, 2015, 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 newly-targeted 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, 2015, our Tonkawa properties contained 0.2 MMBoe of estimated net proved reserves.

- ***Marmaton Formation.*** As of December 31, 2015, we identified 473 gross (283 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.

- ***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, 2015, we operated 30 gross (19 net) producing wells in this formation with an average working interest of 63%. Our Granite Wash properties contained 2.2 MMBoe of estimated net proved reserves as of December 31, 2015, approximately 45% of which are oil and NGLs. We have 363 gross (22 net) remaining drilling locations in the Granite Wash formation as of December 31, 2015.

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. The Atoka and Cherokee formations, in particular, have attractive geologic properties, and we may elect to pursue their development in the future.

Arkoma Basin

Approximately 16% of our estimated proved reserves as of December 31, 2015, and approximately 18% of our average daily net production for the year ended December 2015, were located in the Arkoma basin. The Arkoma basin is a historically prolific, largely gas-prone basin extending from eastern Oklahoma into western Arkansas. The basin produces natural gas, oil and NGLs from multiple horizons, which range in depth from 500 to 21,000 feet.

As of December 31, 2015, we operated approximately 43% of our properties in the Arkoma basin and produce primarily from the Woodford formation.

- ***Woodford Shale Formation.*** Our properties in the Woodford shale formation are located primarily in Atoka, Coal, Pittsburg and Hughes Counties in eastern Oklahoma. The Woodford shale formation ranges from depths of approximately 5,000 feet to 12,700 feet and is composed of 75 to 220-foot thick black siliceous shale in our operating area. The Woodford shale in this area is prospective for natural gas with a high concentration of associated NGLs.

  As of December 31, 2015, we operated 152 gross (59 net) producing wells in the formation with an average working interest of 39%. Our Woodford shale formation properties contained 16.3 MMBoe of estimated net proved reserves as of December 31, 2015, 32% of which are oil and NGLs, and generated an average daily net production of 3.6 MBoe/d for the year ended December 31, 2015. We identified 277 gross (45 net) drilling locations in the Woodford shale formation as of December 31, 2015, of which 20% had proved undeveloped reserves attributed to them.

Drilling Locations

We have identified a total of 2,103 gross (973 net) drilling locations, all of which are horizontal drilling locations. Of these 2,103 locations, 1,536 locations are attributable to acreage that is currently held by production and approximately 412 (20%) are attributable to proved undeveloped reserves as of December 31, 2015. 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. 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 adhere to 128-acre spacing (5 wells per section) while wells in the Woodford shale formation are developed on 80-acre and 120-acre spacing, depending on the area. Wells drilled in the Granite Wash formation were developed on 128-acre or 213-acre spacing. Wells drilled in the Tonkawa and Marmaton formations adhere to 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 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."

The Company currently does not anticipate drilling new wells in the near term. When we resume drilling, our expectation is that we will primarily focus on the Anadarko basin. As a result, the Company will not spud the required number of additional wells per the joint development agreement between Jones Energy and Vanguard Natural Resources within the prescribed time period to maintain rights to the additional future drilling locations. The loss of these drilling locations, along with other near term lease expirations in the Arkoma, have contributed to a reduction in the Company's Woodford proved undeveloped reserve figures and total drilling location count. As of December 31, 2014, the Company had 777 gross (85 net) drilling locations in the Woodford shale formation. The total number of Arkoma drilling locations removed from the Company's 2014 year-end inventory during 2015 totaled 496 gross locations and 40 net locations, including 42 gross (eight net) locations associated with proved undeveloped reserves. These Arkoma drilling locations had no associated PV-10 value in the Company's year-end 2015 proved reserves based on SEC pricing and definitions.

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, 2015, 2014 and 2013, which are based upon reserve reports of Cawley, Gillespie & Associates, Inc., ("Cawley Gillespie"), our independent reserve engineers.

Cawley Gillespie's reports were prepared consistent with the rules and regulations of the SEC regarding oil and natural gas reserve reporting in effect during such periods.

	As of December 31,		
	2015	2014	2013
Reserve Data:			
Estimated proved reserves:			
Oil (MBbls)	25,408	27,683	16,688
Natural gas (MMcf)	261,596	292,277	236,648
NGLs (MBbls)	32,649	38,870	32,915
Total estimated proved reserves (MBoe)(1)	101,657	115,266	89,045
Estimated proved developed reserves:			
Oil (MBbls)	11,032	10,773	7,129
Natural gas (MMcf)	169,651	160,877	139,623
NGLs (MBbls)	19,670	22,555	19,101
Total estimated proved developed reserves (MBoe)(1)	58,977	60,141	49,501
Estimated proved undeveloped reserves:			
Oil (MBbls)	14,376	16,910	9,559
Natural gas (MMcf)	91,945	131,400	97,025
NGLs (MBbls)	12,980	16,315	13,814
Total estimated proved undeveloped reserves (MBoe)(1)	42,680	55,125	39,544
PV-10 (in millions)(2)	$ 470	$ 1,502	$ 1,017
Standardized measure (in millions)(3)	465	1,388	941

(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) 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.

(3) Standardized measure is calculated in accordance with Statement of Financial Accounting Standards No. 69 Disclosures About Oil and Gas Producing Activities, as codified in ASC Topic 932, Extractive Activities—Oil and Gas.

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

	As of December 31,		
	2015	2014	2013
Oil, Natural Gas and NGLs Benchmark Prices:			
Oil (per Bbl)(1)	$50.25	$94.99	$96.78
Natural gas (per MMBtu)(2)	2.59	4.35	3.67
NGLs (per Bbl)(3)	17.63	33.17	28.33

(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, 2015, 2014 and 2013, the average realized prices for oil were $45.97, $91.06 and $91.74 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, 2015, 2014 and 2013, the average realized prices for natural gas were $2.37, $4.16 and $3.13 per MMBtu, respectively.

(3) Prices for NGLs in the table above reflect the average realized prices for the prior 12 months assuming ethane is recovered from the natural gas stream. Benchmark prices for NGLs vary depending on the composition of the NGL basket and current prices for the various components thereof, such as butane, ethane, and propane, among others. Due to declines in ethane prices relative to natural gas prices, beginning in 2012, purchasers of our Woodford production have been electing not to recover ethane from the natural gas stream and instead are paying us based on the natural gas price for the ethane left in the gas stream. As a result of the increased energy content associated with the returned ethane and the absence of plant shrinkage, this ethane rejection has increased the incremental revenue and volumes that we receive for our natural gas product relative to what we would have received if the ethane was separately recovered, but has reduced physical barrels of liquid ethane that we are selling.

Reserves Sensitivities

Assuming NYMEX strip pricing as of February 29, 2016 through 2022 and keeping pricing flat thereafter, instead of 2015 SEC pricing, and leaving all other parameters unchanged, the Company's proved reserves would have been 101.3 MMBoe and the PV-10 value of proved reserves would have been $376 million. This alternative pricing scenario is provided only to demonstrate the impact that the current pricing environment may have on reserves volumes and PV-10. There is no assurance that these prices will actually be realized. The value of our proved reserves as of December 31, 2015 calculated using SEC pricing is higher than the value of our proved reserves calculated using current market prices. Using SEC pricing of December 31, 2015, our total estimated proved reserves were 101.7 MMBoe and the PV-10 value of proved reserves was $470 million.

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 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.

The following table provides a reconciliation of PV-10 to the Standardized Measure of discounted future net cash flows at December 31, 2015, 2014 and 2013.

	As of December 31,		
(in millions)	2015	2014	2013
PV-10	$470	$1,502	$1,017
Present value of future income taxes discounted at 10%	5	114	76
Standardized measure	$465	$1,388	$ 941

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 upper management, including our chief operating officer. 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 engineer. Eric Niccum, our Executive Vice President and Chief Operating Officer, is the technical specialist primarily responsible for overseeing the preparation of our reserves estimates. Mr. Niccum is also responsible for liaising with and oversight of our third-party reserve engineer. Mr. Niccum is a graduate of Purdue University with a Bachelor of Science degree in Mechanical Engineering. He has 22 years of energy experience.

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 engineering audit presented in the Cawley Gillespie report was supervised by W. Todd Brooker, Senior Vice 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, 2015, none of our proved undeveloped reserves at December 31, 2015 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. Our expectation is to continue to fund our drilling and development programs primarily from our cash flow from operations and projected availability under our senior secured revolving credit facility. Based on our current expectations of our cash flows 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 and our expansion activities in the next five years from our cash flow from operations and borrowings under our credit facilities. 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, 2013	39.5
Extensions and discoveries	15.7
Conversion to proved	(10.1)
Purchases of minerals in place	9.8
Sales of minerals in place	—
Revisions of previous estimates	0.2
December 31, 2014	55.1
Extensions and discoveries	3.7
Conversion to proved	(8.2)
Purchases of minerals in place	—
Sales of minerals in place	—
Revisions of previous estimates	(7.9)
December 31, 2015	42.7

Our proved undeveloped reserves have decreased from 55.1 MMBoe at December 31, 2014 to 42.7 MMBoe at December 31, 2015 due to (i) the conversion of 8.2 MMBoe of proved undeveloped reserves to proved developed reserves; (ii) net negative revisions of 7.9 MMBoe, primarily due to reduced commodity pricing partially offset by reduced future development costs; and (iii) additions of 3.7 MMBoe from extensions and discoveries. Proved undeveloped reserves decreased as a percentage of total reserves from 48% for the year ended December 31, 2014 to 42% for the year ended December 31, 2015. Proved undeveloped reserves increased as a percentage of total reserves from 44% for the year ended December 31, 2013 to 48% for the year ended December 31, 2014.

For the year ended December 31, 2015, we converted 8.2 MMBoe of proved undeveloped reserves to proved developed reserves or 15% of total proved undeveloped reserves booked at December 31, 2014. We incurred approximately $105.6 million in capital to convert proved undeveloped reserves to proved developed reserves during the year ended December 31, 2015. Our 2015 capital expenditures totaled $200.1 million excluding the impact of asset retirement costs, of which $173.2 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 $25 million for 2016, with the majority dedicated to capital workovers and field optimization activities. Costs of proved undeveloped reserve development in 2015 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 2015 year-end proved undeveloped reserves is $446 million, all of which is scheduled to be incurred within five years. 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, 2015	2014	2013
Production and Operating Data:			
Net Production Volumes(1):			
Oil (MBbls)	2,583	2,475	1,557
Natural gas (MMcf)	23,839	21,922	17,575
NGLs (MBbls)	2,618	2,345	1,724
Total (MBoe)	9,174	8,474	6,210
Average net production (Boe/d)	25,134	23,216	17,014
Average Sales Price(2):			
Oil (per Bbl)	$44.15	$88.93	$93.22
Natural gas (per Mcf)	1.91	3.78	3.16
NGLs (per Bbl)	13.36	32.14	33.30
Combined (per Boe) realized	21.21	44.65	41.56
Average Costs per Boe:			
Lease operating	$ 4.47	$ 4.46	$ 4.05
Production and ad valorem taxes	1.32	2.66	2.50
Depreciation, depletion and amortization	22.40	21.44	18.38
General and administrative(3)	3.64	3.04	5.14

(1) The Lipscomb SE field constituted approximately 27% of our estimated proved reserves as of December 31, 2015. Our production from the Lipscomb SE field was 2,465 MBoe, 2,862 MBoe and 1,751 MBoe for the years ended December 31, 2015, 2014 and 2013, respectively. The 2015 production was comprised of 889 MBbls of oil, 5,239 MMcf of natural gas and 702 MBbls of NGLs. The 2014 production was comprised of 1,274 MBbls of oil, 5,337 MMcf of natural gas and 699 MBbls of NGLs. The 2013 production was comprised of 858 MBbls of oil, 2,786 MMcf of natural gas and 430 MBbls of NGLs.

The Lipscomb field constituted approximately 24% of our estimated proved reserves as of December 31, 2015. Our production from the Lipscomb field was 2,237 MBoe, 1,467 MBoe and 1,105 MBoe for the years ended December 31, 2015, 2014 and 2013, respectively. The 2015 production was comprised of 637 MBbls of oil, 5,271 MMcf of natural gas and 721 MBbls of NGLs. The 2014 production was comprised of 408 MBbls of oil, 3,394 MMcf of natural gas and 494 MBbls of NGLs. The 2013 production was comprised of 215 MBbls of oil, 2,963 MMcf of natural gas and 395 MBbls of NGLs.

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

(3) General and administrative includes non-cash stock-based compensation of $8.0 million, $4.8 million and $13.6 million for the years ended December 31, 2015, 2014 and 2013, respectively. Excluding stock-based compensation from the above metric results in average general and administrative cost per Boe of $2.77, $2.47 and $2.95 for the years ended December 31, 2015, 2014 and 2013, respectively.

Drilling Activity

The following table sets forth information with respect to wells drilled and completed 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,					
	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Development Wells:						
Productive	53	47	144	119	97	61
Mechanical failure	1	1	1	1	—	—
Dry	—	—	—	—	—	—
Exploratory Wells:						
Productive	—	—	—	—	—	—
Dry	—	—	1	1	—	—
Total Wells:						
Productive	53	47	144	119	97	61
Mechanical failure	1	1	1	1	—	—
Dry	—	—	1	1	—	—
Total(1)	54	48	146	121	97	61

(1) In 2015, the total presented includes one mechanical failure that was not deemed to be a completed well by the Company because it was only drilled to 1,000 feet and abandoned. Therefore, outside of the table above, this mechanical failure has been excluded from our well count.

For the three years ended December 31, 2015, we had one gross (one net) developmental or exploratory well that was deemed to be a dry well. In this same period, we experienced a total of one gross (one net) mechanical failure that was not reservoir related. As of December 31, 2015, there were no development wells in the process of drilling or completion. For the three years ended December 31, 2015, we drilled 294 gross (227 net) wells as operator with over a 99% success rate.

From January 1, 2015 through December 31, 2015, we successfully drilled 53 gross proved undeveloped wells and completed 70 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, 2015.

	Oil		Natural Gas		Total	
	Gross	Net	Gross	Net	Gross	Net
Operated(1)	290	236	308	232	598	468
Non-operated	70	11	348	71	418	82
Total	360	247	656	303	1,016	550

(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, 2015 for each of our producing areas. Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary. Acreage that is prospective for the Tonkawa, Marmaton and other formations is included in these totals as these formations overlie one another throughout much of our acreage. As of December 31, 2015, over 80% of our leasehold acreage was held by existing production.

	Developed Acres		Undeveloped Acres		Total	
	Gross	Net	Gross	Net	Gross	Net
Cleveland	143,607	91,651	37,746	26,049	181,353	117,700
Granite Wash	10,553	6,617	—	—	10,553	6,617
Woodford	12,363	4,417	20	1	12,383	4,418
Other	19,594	7,444	4,341	1,198	23,935	8,642
All properties	186,117	110,129	42,107	27,248	228,224	137,377

Undeveloped Acreage Expirations

The following table sets forth the number of gross and net undeveloped acres as of December 31, 2015 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 2016		Expiring 2017		Expiring 2018		Thereafter	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Cleveland	4,185	2,715	12,641	10,657	19,941	12,071	979	606
Woodford	20	1	—	—	—	—	—	—
Granite Wash	—	—	—	—	—	—	—	—
Other	2,449	1,148	1,575	43	—	—	317	7
All properties	6,654	3,864	14,216	10,700	19,941	12,071	1,296	613

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, 2015 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. Recently, the United States onshore oil and natural gas industry has begun to experience a surplus of drilling and completion rigs, equipment, pipe and personnel, due to significantly lower commodity prices. Although this has provided a temporary respite from the previous high demand environment, there is no assurance that market forces will not revert to the previous situation which 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.

Segment Information and Geographic Areas

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, as described under "—Our Operations—Our Areas of Operations."

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 other leasehold burdens on our properties generally range from 17% to 25%. Our net revenue interests average 55% for our operated leases and 38% including all operated and non-operated leases.

Over 80% of our leases (based on net acreage) are held by 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.

In 2015, changes in NGL prices again altered market conditions. Due primarily to the large supply of the major NGL component products on the market, the composite price of NGL components dropped significantly over the last year. For a discussion of the effect of recent changes in NGL prices, see "Management's Discussion and Analysis of Financial Condition and Results of Operations—Outlook."

During the year ended December 31, 2015, the largest purchasers were Valero Energy Corp. ("Valero"), ETC Field Services LLC, Plains Marketing LP ("Plains Marketing"), NGL Energy Partners LP, and Unimark LLC, which accounted for approximately 18%, 17%, 16%, 15% and 7% 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 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 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 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;

- 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, rules 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, and such changes could result in increased costs for environmental compliance, such as waste handling, 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, rules 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 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. 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 the 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 the site. Under CERCLA, such persons may be subject to joint and several, strict liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the U.S. Environmental Protection Agency, or 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. In the event 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 or leased 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 the 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 wastes, we may be liable for penalties and costs. The EPA and the U.S. Army Corps of Engineers adopted in June 2015 a rule redefining the term "waters of the United States," which establishes the scope of regulated waters under the Clean Water Act. The final rule is expected to expand federal jurisdiction under the Clean Water Act. The rule has been challenged and was stayed by federal courts and will become applicable if the courts do not continue the stay of the rule during the litigation. The EPA also proposed regulations in 2015 under the Clean Water Act to set a zero discharge standard for wastewater discharges from hydraulic fracturing and other natural gas production activities to publicly-owned treatment works. A final rule is expected in 2016.

Safe Drinking Water Act

The SDWA regulates, among other things, underground injection operations. Congress has considered legislation which, if successful, would impose additional regulation under the SDWA upon the use of hydraulic fracturing fluids. If enacted, such legislation 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 proposed legislation would require the disclosure of the chemicals within the hydraulic fluids, which could make it easier for third parties opposing hydraulic fracturing to initiate legal proceedings based on allegations that specific chemicals

used in the process could adversely affect ground water. 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. The EPA has also commenced a study of the potential adverse effects that hydraulic fracturing may have on water quality and public health, and a committee of the U.S. House of Representatives has commenced its own investigation into hydraulic fracturing practices. The 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. If the pending or similar legislation is enacted or other new requirements or restrictions regarding hydraulic fracturing are adopted as a result of these studies, we could incur substantial 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 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, a federal district court has stayed the effectiveness of these BLM rules as challenges to the rules are proceeding. BLM also proposed new rules in January 2016 to reduce venting, flaring, and leaks during oil and natural gas production activities on onshore federal and Indian leases. On October 26, 2015, the U.S. National Park Service, or NPS, proposed to update its regulations governing non-federal oil and gas rights. Most notably, the NPS rulemaking would eliminate two provisions that exempt approximately 60% of the oil and gas operations located within the national park system from the requirement to obtain NPS approval of a proposed plan of operations before commencing non-federal oil and gas operations in an NPS unit and would clarify well stimulation (including hydraulic fracturing) information requirements and operating standards. The Interagency Working Group on Unconventional Natural Gas and Oil was created by Executive Order on April 13, 2012, which is charged with coordinating and aligning federal agency research and scientific studies on unconventional natural gas and oil resources.

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, the Railroad Commission of Texas, implementing a state law passed in June 2011, adopted the Hydraulic Fracturing Chemical Disclosure Rule on December 13, 2011. The rule requires public disclosure of chemicals in fluids used in the hydraulic fracturing process for drilling permits issued after February 1, 2012. Additionally, Texas has authorized the Texas Commission on Environmental Quality to suspend water use rights for oil and gas users in the event of serious drought conditions and has imposed more stringent emissions, monitoring, inspection, maintenance, and repair requirements on Barnett Shale operators to minimize Volatile Organic Compound, or VOC, releases. Other states that we operate in, including Oklahoma, have adopted similar chemical disclosure measures. Some states, including Texas and Oklahoma, also assert the authority to shut down injection wells that are deemed to contribute to induced seismicity, or seismic activity that is caused by human activity. For example, on August 3, 2015, the Oklahoma Corporation Commission adopted a plan calling for mandatory reductions in oil and gas wastewater disposal well volumes to address potential induced seismicity in Oklahoma. 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.

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, on April 17, 2012, the EPA released final rules that establish new air emission controls for oil and natural gas production and natural gas processing operations. The rules became effective on October 15, 2012. Specifically, the EPA's rule package includes New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds, and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. The rules establish specific requirements regarding 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 may reconsider some aspects of the rules. The case remains in abeyance. The EPA has since made several changes to the rules and has indicated that it may reconsider other aspects of the rules. Depending on the outcome of such judicial proceedings and regulatory actions, the rules may be further modified or rescinded or the EPA may issue new rules. These rules that took effect on October 15, 2012, 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, on September 18, 2015 the EPA proposed to regulate emissions of methane and volatile organic compounds from new and modified sources in the oil and gas sector as a measure to implement the Climate Action Plan and

proposed 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. Final rules are expected in 2016. Further, in 2015, the EPA adopted a lower national ambient air quality standard for ozone. This lower standard may cause 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.

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 can attach 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.

We conduct operations in areas where certain species that are listed as threatened or endangered under the ESA may be present. For example, our operations in the Arkoma basin of Oklahoma overlap with the range of the American Burying Beetle, which is listed as endangered. The presence of endangered or threatened species may force us to modify or terminate our operations in certain areas. Additionally, the designation of previously unidentified endangered or threatened species could cause us to incur additional costs or limit future development activity in the affected areas. 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. 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 will exempt from "take" certain oil and gas and other activities conducted by a participant that result in an "incidental take" of the Lesser Prairie Chicken as long as the participant is enrolled in, and operating in compliance with, a range-wide conservation plan endorsed by the Fish and Wildlife Service. The range-wide conservation plan also includes a Candidate Conservation Agreement with Assurances (CCAA) component that provides "take" coverage for properties enrolled into the CCAA before the listing is effective. To mitigate the risk of liability from "incidental takes" of the Lesser Prairie Chicken, we enrolled affected leasehold interests in the CCAA. However, environmental groups challenged the listing decision and special 4(d) rule in a suit filed in federal district court in the District of Columbia on June 17, 2014. These groups are attempting to compel a more restrictive listing of the Lesser Prairie Chicken as endangered, rather than threatened, and are seeking to invalidate the special 4(d) rule. While these same environmental groups also filed a notice of intent to sue concerning the CCAA on April 10, 2014, the suit filed in federal court did not include a challenge to the CCAA. Other suits challenging the scientific basis for the listing were filed by affected states and the oil and gas industry in Texas and Oklahoma. 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. The Fish and Wildlife Service moved to keep the rule in effect pending further agency action; the court has ordered the parties to mediate. We continue to evaluate the impact of these rules and the ongoing legal challenges on our operations. As with any other species in areas that we operate, the listing of the Lesser Prairie Chicken under the Endangered Species Act 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 actively considered legislation to reduce emissions of GHGs, but no legislation has yet passed. 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. 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. The rule requires reporting of GHG emissions by regulated entities to the EPA on an annual basis. Reporting was first required in 2012 for emissions occurring in 2011. 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, more than 20 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, on October 23, 2015, the EPA published the final Clean Power Plan rule. While the rule directly applies to power plants, the Clean Power Plan is targeted at creating a shift from fossil fuels toward renewable power generation; however, the rule has been stayed and is not effective during the judicial review. Also, 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 will be open for signing on April 22, 2016 and, if it comes into force, would require 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 impact of such future programs cannot be predicted, but we do not expect our operations to be affected any differently than other similarly situated domestic competitors.

In addition to legislative and regulatory developments, plaintiffs have brought judicial actions under common law theories against greenhouse gas emitting companies in recent years. For example, municipal plaintiffs in *Kivalina v. ExxonMobil Corporation, et al*, alleged that the defendant corporations' contributions to global warming caused property damage associated with rising sea levels. Although the plaintiffs in *Kivalina* were ultimately unsuccessful, there is a continuing litigation risk associated with greenhouse gas-emitting activities.

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 proposed a rule in September 2015 to set standards for methane and volatile organic compound emissions from new and modified sources in the oil and gas sector, with a final rule expected in 2016. As a result of this continued regulatory focus and other factors, 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 of pollution control activities for the years ended December 31, 2015, 2014 or 2013. Additionally, we are not aware of any environmental issues or claims that will require material capital expenditures during 2016 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 field offices in Canadian, Texas and McAlester, Oklahoma.

Employees

As of December 31, 2015, we had 116 employees, including 46 technical (geosciences, engineering, land), 34 field operations, 31 corporate (finance, accounting, planning, business development, IT, human resources, office management) and 5 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. Our reports filed with the SEC are made available to read and copy at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C., 20549. You may obtain information about the Public Reference Room by contacting the SEC at 1-800-SEC-0330. Reports filed with the SEC are also made available on its website at www.sec.gov.

Our common stock is listed and traded on the New York Stock Exchange under the symbol "JONE." Our reports, proxy statements and other information filed with the SEC can also be inspected and copied at the New York Stock Exchange, 20 Broad Street, New York, New York 10005.

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:

A substantial or extended decline in oil, natural gas or NGL prices may 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. The markets for oil, natural gas and NGLs historically have been volatile and were depressed throughout 2015. As an example, during 2015, the NYMEX WTI oil price ranged from more than $61 per Bbl to below $35 per Bbl, the lowest price seen since 2009, and the average daily price for NYMEX Henry Hub natural gas reached a low of $1.63 per MMBtu in December, the lowest price since 1999. 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;

- 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;
- localized supply and demand fundamentals and transportation availability;
- weather conditions and natural disasters;
- domestic, local and foreign governmental regulations and taxes;
- 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 29% of our 2015 production, and we realized an average price of $13 per barrel, a 58% decrease from the average realized price of our 2014 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. If oil, natural gas and NGL prices continue to deteriorate or remain at depressed levels, we anticipate that the borrowing base under our senior secured revolving credit facility, which is revised periodically, will be reduced at some point, which would negatively impact our borrowing ability. Additionally, prices could reduce our cash flows to a level that would require us to borrow to fund our capital budget. Lower oil, natural gas and NGL prices may also reduce the amount of oil, natural gas and NGLs that we can 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 an example, total proved reserves decreased by 12%, from 115.3 MMBoe as of December 31, 2014 to 101.7 MMBoe as of December 31, 2015, primarily due to the decline in commodity prices. 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.

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;
- 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 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.

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 total capital expenditures for 2015 were $200.1 million excluding the impact of asset retirement costs. The Company has established an initial capital budget of $25 million for 2016. 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, 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, borrowings under our senior secured revolving credit facility 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 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. Our senior secured revolving credit facility and the indentures governing our senior notes due 2022 (the "2022 Notes") and senior notes due 2023 (the "2023 Notes") may 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 under our senior secured revolving credit facility and 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.

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.

Approximately 42% of our total estimated proved reserves were classified as proved undeveloped as of December 31, 2015. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. In addition, continued 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.

Our hedging strategy may be ineffective in reducing the impact of commodity price volatility from our cash flows, 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 enter 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. In addition, our senior secured revolving credit facility limits the aggregate notional volume of commodities that can be covered under commodity derivative contracts we can enter into and, as a result, we will continue to have direct commodity price exposure on the unhedged portion of our production volumes. For the years ending December 31, 2016, 2017, and 2018, approximately 26%, 62%, and 71%, respectively, of our estimated total oil, natural gas and NGL production from proved reserves, based on our reserve report as of December 31, 2015, 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.

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.

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.

***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. 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. 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 initial capital budget for 2016 is $25 million. We are not currently drilling on our acreage, and there can be no assurances regarding when we will resume drilling. Unless we resume drilling such that production is established within the spacing units covering the undeveloped acres on which some of the potential locations are obtained, the leases for such acreage will expire.

Continued low commodity prices or future price declines or downward reserve revisions may result in write-downs of the carrying values of our properties.

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. We may incur impairment charges and related reductions in proved reserves in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken. If commodity prices remain low relative to their historical levels, we may incur future impairments to long-lived assets.

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, 2015. 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 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.

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. For example, we do not currently anticipate drilling new wells on our Arkoma Woodford acreage. As a result, we will not spud the required number of additional wells per the joint development agreement between us and Vanguard Natural Resources within the prescribed time period to maintain rights to the additional future drilling locations. The loss of these drilling locations, along with other near term lease expirations in the Arkoma, have contributed to a reduction in our Woodford proved undeveloped reserve figures and total drilling location count.

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, 2015 excluding hedging impacts would decrease approximately $139.7 million holding all costs constant. If natural gas prices decline by $1.00 per Mcf, then our standardized measure as of December 31, 2015 excluding hedging impacts would decrease by approximately $101.4 million holding all costs constant.

Over 99% of our estimated proved reserves are located in the Anadarko and Arkoma basins in the Texas Panhandle and Oklahoma, making us vulnerable to risks associated with operating in one geographic area.

Over 99% of our estimated proved reserves as of December 31, 2015 were located in the Anadarko and Arkoma basins in the Texas Panhandle and Oklahoma. Approximately 79% of our 2015 production was from the Cleveland formation where properties are located in four contiguous counties of Texas and Oklahoma. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, availability of equipment, facilities, personnel or services market limitations or interruption of the processing or transportation of oil, natural gas or NGLs. In addition, the effect of fluctuations on supply and demand may become more pronounced within specific geographic oil and natural gas producing areas such as our properties producing from the Cleveland formation, which may cause these conditions to occur with greater frequency or magnify the effects of these conditions. Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. Such delays or interruptions 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, 2015 purchases by our top five customers accounted for approximately 18%, 17%, 16%, 15% and 7%, 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. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

In addition, our senior secured revolving credit facility impose certain limitations on our ability to enter into mergers or combination transactions. Our senior secured revolving credit facility also limits our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses.

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 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.

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 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 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 greater 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 has been strong in hiring experienced personnel, particularly in the engineering and technical, accounting and financial reporting, tax and land departments. In addition, competition is strong for attractive oil and natural gas producing properties, oil and natural gas companies, and undeveloped leases and drilling rights. 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 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.

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;
- 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.

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 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, wetlands, ephemeral streams, frontier and other protected areas; 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. 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, may be adopted in the future. The trend of more expensive and stringent environmental legislation and regulations applied to the oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting 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 many of 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. In addition, the EPA issued a notice of rulemaking under the Toxic Substances Control Act relating to chemical substances and mixtures used in oil and gas exploration and production. 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.

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, Texas adopted a law in June 2011 requiring disclosure to the Railroad Commission of Texas, or TRRC, and the public of certain information regarding the components of the fluids used in the hydraulic fracturing process. On December 13, 2011, the TRRC finalized regulations requiring public disclosure of chemicals in fluids used in the hydraulic fracturing process for drilling permits issued after February 1, 2012. In addition, on October 20, 2011, Louisiana adopted new regulations for hydraulic fracturing operations in the state. These new regulations require hydraulic fracturing operators to publicly disclose the volume of hydraulic fracturing fluid, the type, trade name, supplier and volume of additives, and a list of chemical compounds contained in the additive, along with its maximum concentration, subject to certain trade secret protections. However, trade secret chemicals must be identified by their chemical family. 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. In addition, the Oklahoma Corporation Commission has adopted rules prohibiting water pollution resulting from hydraulic fracturing operations and requiring disclosure of chemicals used in hydraulic fracturing.

Texas has also authorized the Texas Commission on Environmental Quality to suspend water use rights for oil and gas users in the event of serious drought conditions and has imposed more stringent emissions, monitoring, inspection, maintenance, and repair requirements on Barnett Shale operators to minimize Volatile Organic Compound, or VOC, releases. Also, Louisiana requires operators to minimize releases of gases into the open air after hydraulic fracturing in certain urban areas.

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 either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating 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. The EPA is conducting a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. The EPA released its first progress report on this study in December 2012 and has also released several papers for public and peer review. The EPA released its draft assessment of the potential impacts to drinking water resources from hydraulic fracturing for public comment and peer review in June 2015.

The EPA completed its study of wastewater resulting from hydraulic fracturing activities and, in April 2015, proposed a pretreatment standard of zero discharge, which if adopted will prohibit discharges 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. These 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. The Interagency Working Group on Unconventional Natural Gas and Oil was created by Executive Order on April 13, 2012, which is charged with coordinating and aligning federal agency research and scientific studies on unconventional oil and natural gas resources.

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, a federal district court has stayed the effectiveness of these BLM rules as challenges to the rules are proceeding. BLM released a proposed rule in January 2016 that would require reductions in venting, flaring, and leaks during oil and natural gas production activities on onshore federal and Indian leases. Similarly, on October 26, 2015, the NPS, proposed to update its regulations governing non-federal oil and gas rights. Most notably, the NPS rulemaking would eliminate two provisions that exempt approximately 60% of the oil and gas operations located within the national park system from the requirement to obtain NPS approval of a proposed plan of operations before commencing nonfederal oil and gas operations in an NPS unit and would clarify well stimulation (including hydraulic fracturing) information requirements and operating standards.

State and federal regulatory agencies recently have focused on a possible connection between the operation of injection wells used for oil and gas waste waters and an observed increase in minor seismic activity and tremors. When caused by human activity, such events are called induced seismicity. In a few instances, operators of injection wells in the vicinity of minor seismic events have reduced injection volumes or suspended operations, often voluntarily. A 2012 report published by the National Academy of Sciences concluded that only a very small fraction of the tens of thousands of injection wells have been suspected to be, or have been, the likely cause of induced seismicity. However, 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 activity is likely to be contributing to seismic activity. The Oklahoma Corporation Commission 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, on August 3, 2015, the Oklahoma Corporation Commission adopted a plan calling for mandatory reductions in oil and gas wastewater disposal well volumes to address potential induced seismicity in Oklahoma. Regulatory agencies are continuing to study possible linkage between injection activity and induced seismicity.

Further, on April 17, 2012, the EPA released final rules to subject oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS, programs. These rules became effective on October 15, 2012. 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. Depending on the outcome of such judicial proceedings and regulatory actions, the rules may be further modified or rescinded or the EPA may issue new rules. 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, on September 18, 2015, the EPA proposed to regulate emissions of methane and volatile organic compounds from new and modified sources in the oil and gas sector as a measure to implement the Climate Action Plan. On the same day, the EPA also proposed 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 a aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting processes and requirements. Final rules are expected in 2016. The Administration has also stated that other federal agencies, including the Bureau of Land Management, the Pipeline and Hazardous Materials Safety Administration, and the Department of Energy will impose new or more stringent regulations on the oil and gas sector that will have the effect of further reducing methane emissions. 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.

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. The first reports were due in 2012 for emissions occurring in 2011. 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.

The Climate Action Plan also calls for reductions of methane emissions. As previously mentioned, the federal administration has proposed a rule to require methane reductions from oil and gas sources, with a final rule expected in 2016. In addition, 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. On October 23, 2015, the EPA published the final Clean Power Plan. While the rule directly applies to power plants, the Clean Power Plan is targeted at creating a shift from fossil fuels toward renewable power generation; however the rule has been stayed and is not effect during the judicial review. Also, 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 will be open for signing on April 22, 2016 and, if it comes into force, would require 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. Consequently, 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 Texas and Oklahoma, 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. On August 3, 2015, the Oklahoma Corporation Commission adopted a plan calling for mandatory reductions in oil and gas wastewater disposal well volumes to address potential induced seismicity in

Oklahoma. 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 proposed to prohibit 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, the cost to transport and dispose of that water, including the cost of complying with regulations concerning water disposal, may reduce our profitability.

In the event 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.

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.

Risks Relating to Financings and Ownership:

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. For example, as of December 31, 2015, we had an unused borrowing capacity of approximately $400 million under our revolving credit facility, subject to compliance with financial covenants. The impact of a 1.0% increase in interest rates on an assumed borrowing of the full $510 million available under our revolving credit facility would result in increased annual interest expense of approximately $5.1 million and a corresponding decrease in our net income. 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 borrowing base under our revolving credit facility is subject to redetermination and any reduction in the borrowing base may reduce our liquidity or result in our having to repay indebtedness under our revolving credit facility earlier than anticipated.

The borrowing base under our revolving credit facility will be redetermined at least semi-annually on or about April 1 and October 1 of each year, with such redetermination based primarily on reserve reports using lender commodity price expectations at such time. JEH and the administrative agent (acting at the direction of lenders holding at least 66⅔% of the outstanding loans) may each request one unscheduled borrowing base redetermination between each scheduled redetermination. In addition, the lenders may elect to redetermine the borrowing base upon the occurrence of certain defaults under our material operating agreements or upon the cancellation or termination of certain of our joint development agreements. The borrowing base may also be reduced as a result of our issuance of unsecured notes, our termination of material hedging positions or our consummation of significant asset sales. If current low commodity prices continue through such redetermination events, the borrowing base under our revolving credit facility may be reduced.

Certain federal regulatory agencies, including the Office of the Comptroller of the Currency (OCC), the Federal Reserve, and the Federal Deposit Insurance Corp., have recently focused on oil and gas lenders' examinations and ratings of reserve-based loans, with a view towards encouraging such lenders to reduce their exposure to potentially substandard loans to oil and gas companies. In April 2014, the OCC issued the "Oil and Gas Production Lending" bank examination booklet, which details potential regulatory requirements related to reserve-based lending. Whether or not these regulatory agencies are successful in implementing stricter requirements related to reserve-based lending, oil and gas lenders may respond to these discussions by taking a more conservative approach in their lending practices, which could adversely impact future borrowing base redeterminations under our revolving credit facility.

Any reduction in the borrowing base will reduce our liquidity, and, if the reduction results in the outstanding amount under our revolving credit facility exceeding the borrowing base, we will be required to repay the deficiency within a short period of time. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources—Credit Facilities."

The Jones family and Metalmark Capital, our primary private equity investor, 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, 2015, the Jones family and Metalmark Capital held approximately 51.3% of the combined voting power of Jones Energy, Inc. Although the Jones family and Metalmark Capital are entitled to act separately in their own respective interests with respect to their ownership interests in Jones Energy, Inc., the Jones family and Metalmark Capital will have the ability to elect all of the members of our board of directors, and thereby control our management and affairs. In addition, the Jones family and Metalmark Capital have significant influence over all matters that require approval by our stockholders, including mergers and other material transactions.

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.

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.

Over time, we have had limited accounting personnel to execute our accounting processes and limited other supervisory resources with which to address our internal control over financial reporting. As such, we have not maintained an effective control environment to ensure that the design and execution of our controls has consistently resulted in effective review of our financial statements and supervision by appropriate individuals. As a result of these factors, certain material misstatements in our annual financial statements were discovered and brought to the attention of our management by our independent registered public accounting firm for correction. These material misstatements were the result of a combination of control deficiencies which we concluded constituted a material weakness in our control environment. A material weakness is a control deficiency, or a combination of control deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis.

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 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.

For as long as we are an emerging growth company, we will not be required to comply with certain requirements that apply to other public companies.

We continue to qualify as an "emerging growth company" under the Jumpstart Our Business Startups Act (the "JOBS Act"). By virtue of such, we may take advantage of certain exemptions from various reporting requirements that are applicable to other public companies that are not emerging growth companies, including not being required to provide an auditor's attestation report on management's assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404 and reduced disclosure obligations regarding executive compensation in our periodic reports. We will remain an emerging growth company for up to five years, although we will lose that status sooner if we have more than $1.0 billion of revenues in a fiscal year, have more than $700 million in market value of our Class A common stock held by non-affiliates, or issue more than $1.0 billion of non- convertible debt over a three-year period.

To the extent that we rely on any of the exemptions available to emerging growth companies, you will receive less information about our executive compensation and internal control over financial reporting than issuers that are not emerging growth companies.

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

The oil and gas industry has become increasingly dependent on digital technologies to conduct certain exploration, development, production, processing and distribution activities. For example, we depend on digital technologies to interpret seismic data, manage drilling rigs, production equipment and gathering and transportation systems, conduct reservoir modeling and reserves estimation and process and record financial and operating data. As an oil and natural gas producer, we face various security threats, including cyber-security threats. Cyber-security attacks in particular are increasing and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. Although to date we have not experienced any material losses related to cyber-security attacks, we may suffer such losses in the future. Moreover, the various procedures and controls we use to monitor and protect against these threats and to mitigate our exposure to such threats may not be sufficient in preventing security threats from materializing. If any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations or cash flows.

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 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.

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. Our ability to make tax distributions, and pay taxes and the TRA liability may be limited by our structure and available liquidity. To the extent that we incur cash income tax liabilities or are required to make cash tax distributions and cash payments of the TRA liability it would impact our liquidity and reduce cash available for other uses.

We are not drilling new wells at this time, which limits our planned capital spending. As a result of this, our tax deductions associated with intangible drilling costs would be significantly lower, reducing our ability to offset our taxable income. Further, considering the recognition of income associated with debt extinguishment by JEH, we are likely to be allocated taxable income in excess of any such tax deductions relating to 2016. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Outlook" and Note 15, "Subsequent Events," in the Notes to Consolidated Financial Statements for further discussion of these items. 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 described below. Based on our 2016 budget and debt extinguishment through February 29, 2016, we estimate that the amount of tax distributions to JEH unitholders (other than us), plus the amount of our cash tax liabilities, in 2016 would be approximately $38.3 million based on information available as of this filing. Estimating the tax distributions required under the operating agreement is imprecise by nature, highly uncertain, and dependent upon a variety of factors. Additional debt extinguishment during the remainder of 2016 would increase the amount of potential tax payments to JEH unitholders (other than us) and the amount of our cash tax liabilities, whereas a decision to deploy capital to drill new wells would decrease the amount of any potential tax distributions and liabilities.

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 will be subject to U.S. federal income tax at rates of up to 35% (and a 20% alternative minimum tax in certain cases), 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 TRA, 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 our revolving credit agreement, 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 TRA 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."

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 pre-IPO owners. 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 pre-IPO owners' 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 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 cases, 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.

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, which calculation of anticipated future tax benefits will be based upon certain assumptions and deemed events set forth in the Tax Receivable Agreement, including the assumption that we have sufficient taxable income to fully utilize such benefits and that any JEH Units that the pre-IPO Owners or their permitted transferees own on the termination date are deemed to be exchanged 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.

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 pre-IPO Owner will be netted against payments otherwise to be made, if any, to such pre-IPO owner 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.

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.

Items 4. Mine Safety Disclosures

Not applicable.

Part II

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

Our common stock is listed on the New York Stock Exchange ("NYSE") under the symbol "JONE."

The following table sets forth the range of high and low sales prices of our common stock as reported by the NYSE for the periods indicated.

	2015		2014	
	High	Low	High	Low
1st Quarter	$12.60	$7.74	$18.32	$13.05
2nd Quarter	$11.63	$8.39	$20.57	$14.50
3rd Quarter(1)	$ 9.15	$4.41	$20.79	$17.26
4th Quarter	$ 6.05	$3.20	$18.82	$ 9.50

(1) For the third quarter of 2013, the data represents the period from July 24, 2013, the date on which our common stock began trading on the NYSE, through September 30, 2013.

On February 29, 2016, the last sale price of our common stock, as reported on the NYSE, was $1.50 per share. As of February 29, 2016, there were 30,550,907 shares of Class A common stock outstanding held by approximately eight stockholders of record and 31,273,130 shares of Class B common stock outstanding held by approximately eleven stockholders of record.

Dividend Policy

We have not paid any dividends and do not anticipate declaring or paying any cash dividends to holders of our Class A common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the growth of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon then existing conditions, including our results of operations, financial condition, capital requirements, investment opportunities, statutory restrictions on our ability to pay dividends and other factors our board of directors may deem relevant. In addition, our senior secured revolving credit facility, the 2022 Notes and the 2023 Notes prohibit us from paying dividends.

Issuer Purchases of Equity Securities

None.

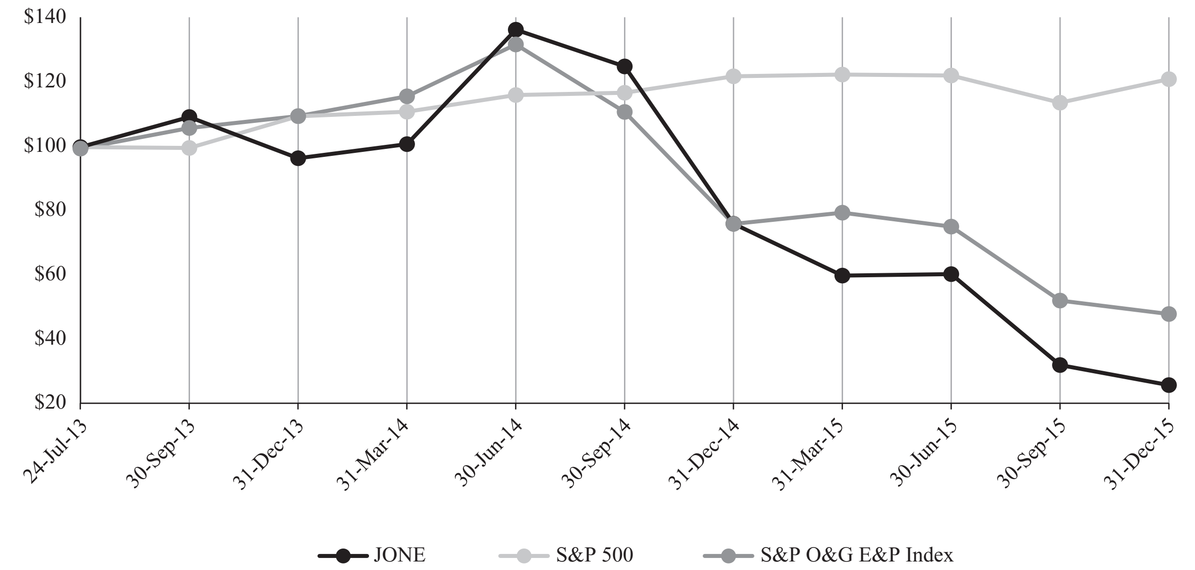
Sales of Unregistered Equity Securities

None.

Stock Performance Graph

The following stock performance graph and related information shall not be deemed "soliciting material" or to be "filed" with the SEC, nor shall such information be incorporated by reference into any future filing under the Securities Act of 1933, as amended (the "Securities Act"), or the Securities Exchange Act of 1934, as amended (the "Exchange Act"), except to the extent that we specifically incorporate such information by reference into such a filing. The graph and information is included for historical comparative purposes only and should not be considered indicative of future stock performance.

The graph compares the cumulative total shareholder return to Jones Energy, Inc.'s common stockholders as compared to the cumulative total returns on the Standard & Poor's 500 index ("the S&P 500 Index") and the Standard and Poor's 500 Oil & Gas Exploration & Production Index ("S&P 500 O&G E&P Index") since the time of our IPO. The graph was prepared assuming $100 was invested in our common stock at its initial public offering price of $15.00 per share and invested in the S&P 500 Index and the S&P 500 O&G E&P Index on July 24, 2013 at the closing price on such date and tracked through December 31, 2015.



Securities Authorized for issuance Under Equity Compensation Plans

The following table presents the securities authorized for issuance under the Jones Energy, Inc. 2013 Omnibus Incentive Plan (the "LTIP") as of December 31, 2015.

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)	—	—	2,303,615(2)
Equity compensation plans not approved by security holders	—	—	—
Total	—	—	2,303,615

(1) Our 2013 Omnibus Incentive Plan (the "LTIP") was approved by our board of directors in July 2013 and took effect on July 29, 2013. The LTIP was also approved by our shareholders at the Annual Meeting of Shareholders on July 10, 2013.

(2) The LTIP may consist of the following components: restricted stock, stock options, performance awards, restricted stock units, bonus stock awards, 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 3,850,000 shares of our Class A common stock. Our board of directors had approved total cumulative awards of 1,546,385 shares of restricted Class A common stock under the LTIP as of December 31, 2015, net of forfeitures and other adjustments that return previously awarded shares to the pool of remaining available shares.

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, 2015, 2014, 2013, 2012 and 2011. 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)	2015	2014	2013	2012	2011
Operating revenues					
Oil and gas sales	$ 194,555	$378,401	$258,063	$148,967	$167,261
Other revenues	2,844	2,196	1,106	847	1,022
Total operating revenues	197,399	380,597	259,169	149,814	168,283
Operating costs and expenses					
Lease operating	41,027	37,760	25,129	22,151	20,860
Production taxes	12,130	22,556	15,517	6,529	6,021
Exploration	6,551	3,453	16,125	356	780
Depletion, depreciation and amortization	205,498	181,669	114,136	80,709	68,906
Impairment of oil and gas properties	—	—	—	18,821	31,970
Accretion of ARO liability	1,087	770	608	533	413
General and administrative	33,388	25,763	31,902	15,875	16,679
Other operating	4,188	—	—	—	—
Total operating expenses	303,869	271,971	203,417	144,974	145,629
Operating income (loss)	(106,470)	108,626	55,752	4,840	22,654
Other income (expense)					
Interest expense	(61,289)	(38,805)	(27,409)	(21,177)	(18,704)
Net gain (loss) on commodity derivatives	158,753	189,641	(2,566)	16,684	34,490
Gain on bargain purchase	—	—	—	—	26,208
Other income (expense)	(2,852)	(7,624)	(3,443)	(2,953)	(4,149)
Other income (expense), net	94,612	143,212	(33,418)	(7,446)	37,845
Income (loss) before income tax	(11,858)	251,838	22,334	(2,606)	60,499
Income tax provision					
Current	111	53	85	—	—
Deferred	(2,892)	26,165	(156)	473	173
Total income tax provision (benefit)	(2,781)	26,218	(71)	473	173
Net income (loss)	(9,077)	225,620	22,405	(3,079)	60,326
Net income (loss) attributable to non-controlling interests	(6,696)	184,484	24,591	—	—
Net income (loss) attributable to controlling interests	$ (2,381)	$ 41,136	$ (2,186)	$ (3,079)	$ 60,326
Earnings per share:					
Basic	$ (0.09)	$ 3.28	$ (0.17)		
Diluted	$ (0.09)	$ 3.28	$ (0.17)		
Weighted average shares outstanding:					
Basic	26,816	12,526	12,500		
Diluted	26,816	12,535	12,500		
Other Supplementary Data:					
EBITDAX(1)	$ 268,417	$303,014	$204,997	$135,741	$127,960
Adjusted net income(2)	$ 2,220	$ 68,824	$ 56,425	$ 29,767	$ 35,674

(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.

(in thousands of dollars)	Year Ended December 31, 2015	2014	2013	2012	2011
Statement of Cash Flow Data					
Net cash flow provided by operating activities	$ 69,030	$ 265,423	$ 148,573	$ 84,550	$ 120,217
Net cash used in investing activities	(168,401)	(463,903)	(368,277)	(337,636)	(318,963)
Net cash provided by financing activities	107,698	188,226	219,798	270,676	186,322
Net increase (decrease) in cash	$ 8,327	$ (10,254)	$ 94	$ 17,590	$ (12,424)

(in thousands of dollars)	As of December 31, 2015	2014	2013	2012	2011
Balance Sheet Data					
Cash and cash equivalents	$ 21,893	$ 13,566	$ 23,820	$ 23,726	$ 6,136
Other current assets	172,611	230,797	121,770	74,886	88,546
Total current assets	194,504	244,363	145,590	98,612	94,682
Property and equipment, net	1,639,639	1,642,908	1,300,672	1,010,742	743,575
Other long-term assets	111,269	107,578	41,717	41,332	42,878
Total assets	1,945,412	$1,994,849	$1,487,979	$1,150,686	$881,135
Current liabilities	$ 67,906	$ 229,281	$ 179,668	$ 93,360	$108,440
Long-term debt	847,912	860,000	658,000	610,000	415,000
Other long-term liabilities	92,742	52,218	26,187	18,926	11,787
Total stockholders' / members' equity	936,852	853,350	624,124	428,400	345,908
Total liabilities and stockholders' / members' equity	1,945,412	$1,994,849	$1,487,979	$1,150,686	$881,135

Non-GAAP financial measures

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

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

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

(in thousands of dollars)	Year Ended December 31, 2015	2014	2013	2012	2011
Reconciliation of EBITDAX to net income					
Net income (loss)	$ (9,077)	$ 225,620	$ 22,405	$ (3,079)	$ 60,326
Interest expense	61,289	38,805	27,409	21,177	18,704
Exploration expense	6,551	3,453	16,125	356	780
Income taxes	(2,781)	26,218	(71)	473	173
Amortization of deferred financing costs	3,169	3,070	2,644	3,511	2,907
Depreciation and depletion	205,498	181,669	114,136	80,709	68,906
Impairment of oil and natural gas properties	—	—	—	18,821	31,970
Accretion of ARO liability	1,087	770	608	533	413
Reduction of TRA liability	(1,984)	—	—	—	—
Other non-cash charges	1,023	376	79	129	(59)
Stock compensation expense	7,562	4,040	10,838	570	1,134
Other compensation expense	455	758	2,719	—	—
Net (gain) loss on derivative contracts	(158,753)	(189,641)	2,566	(16,684)	(34,490)
Current period settlements of matured derivative contracts	149,801	4,476	5,209	29,783	2,162
Amortization of deferred revenue	(1,960)	(1,154)	(469)	—	—
Gain on bargain purchase	—	—	—	—	(26,208)
(Gain) loss on sale of assets	3	(297)	78	(1,162)	859
Stand-by rig costs	4,188	—	—	—	—
Financing expenses and other loan fees	2,346	4,851	721	604	383
EBITDAX	$ 268,417	$ 303,014	$204,997	$135,741	$127,960

Adjusted Net Income and Adjusted Earnings per Share are supplemental non- GAAP financial measures that are used by management and external users of the Company's consolidated financial statements. We define Adjusted Net Income as net income excluding the impact of certain non-cash items including gains or losses on commodity derivative instruments not yet settled, impairment of oil and gas properties, non-cash compensation expense, and the other items described below. We define Adjusted Earnings per Share as earnings per share plus that portion of the components of adjusted net income allocated to the controlling interests divided by weighted average shares outstanding. We believe adjusted net income and adjusted earnings per share are useful to investors because they provide readers with a more meaningful measure of our profitability before recording certain items for which the timing or amount cannot be reasonably determined. However, these measures are provided in addition to, not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP. Our computations of adjusted net income and adjusted earnings per share may not be comparable to other similarly titled measures of other companies.

The following 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)	2015	2014	2013	2012	2011
Net income (loss)	$ (9,077)	$ 225,620	$22,405	$ (3,079)	$ 60,326
Net (gain) loss on derivative contracts	(158,753)	(189,641)	2,566	(16,684)	(34,490)
Current period settlements of matured derivative contracts	149,801	4,476	5,209	29,783	2,162
Impairment of oil and gas properties	—	—	—	18,821	31,970
Exploration	6,551	3,453	16,125	356	780
Non-cash stock compensation expense	7,562	4,040	10,838	570	1,134
Other non-cash compensation expense	455	758	2,719	—	—
Gain on bargain purchase	—	—	—	—	(26,208)
Stand-by rig costs	4,188	—	—	—	—
Financing expenses	2,250	3,761	—	—	—
Reduction of TRA liability	(1,984)	—	—	—	—
Tax impact of adjusting items(1)	(1,106)	16,357	(3,437)	—	—
Change in valuation allowance	2,333	—	—	—	—
Adjusted net income	2,220	68,824	56,425	$ 29,767	$ 35,674
Adjusted net income attributable to non-controlling interests	1,275	56,208	52,679		
Adjusted net income attributable to controlling interests	945	12,616	3,746		
Earnings per share (basic and diluted)	$ (0.09)	$ 3.28	$ (0.17)		
Net (gain) loss on derivative contracts	(2.68)	(3.85)	0.43		
Current period settlements of matured derivative contracts	2.48	0.09	(0.01)		
Exploration	0.12	0.07	0.31		
Non-cash stock compensation expense	0.13	0.08	0.02		
Other non-cash compensation expense	0.01	0.02	—		
Stand-by rig costs	0.06	—	—		
Financing expenses	0.03	0.08	—		
Reduction of TRA liability	(0.07)	—	—		
Tax impact of adjusting items(1)	(0.04)	1.24	(0.28)		
Change in valuation allowance	0.09	—	—		
Adjusted earnings per share (basic and diluted)	$ 0.04	$ 1.01	$ 0.30		
Effective tax rate on net income attributable to controlling interests	38.9%	35.7%	36.9%		

(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.

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

Jones Energy, Inc. is 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. The Company's assets are located within the Anadarko and Arkoma basins of Texas and Oklahoma, and are owned by JEH and its operating subsidiaries. The Company is headquartered in Austin, Texas. We have drilled 827 total wells, including over 650 horizontal wells, since our formation. We optimize returns through a disciplined emphasis on controlling costs and promoting operational efficiencies, and we believe we are recognized as one of the lowest-cost drilling and completion operators in the Cleveland and Woodford shale formations.

As of December 31, 2015, our total estimated proved reserves were 101.7 MMBoe, of which 58% were classified as proved developed reserves. Approximately 25% of our total estimated proved reserves as of December 31, 2015 consisted of oil, 32% consisted of NGLs, and 43% consisted of natural gas.

Outlook

The markets for oil, natural gas and NGLs, historically, have been volatile. During late 2014 and 2015, the oil and natural gas industry experienced a significant decline in commodity prices. As an example, during 2015, the NYMEX WTI oil price ranged from a high of approximately $61 per Bbl to a low of approximately $35 per Bbl, the lowest price since 2009, and the average daily price for NYMEX Henry Hub natural gas reached a low of $1.63 per MMBtu in December, the lowest price since 1999. Depressed commodity prices have continued into 2016, and historically low commodity prices may exist for an extended period. The price we receive for our oil, natural gas and NGLs heavily influences our revenue, profitability, liquidity, access to capital and prospects for future 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. These markets will likely continue to be volatile in the future.

We believe that the commodity pricing environment will remain challenging for our business in 2016. However, we believe that our strong hedge position, our ability to further reduce drilling and completion costs, and our existing drilling inventory of 2,103 gross drilling locations will enable us to compete for strategic acquisitions and joint development opportunities, and if commodity prices rise in the future to generate attractive economic rates of return from the development of our inventory of drilling locations.

The estimated mark-to-market value of our commodity price hedges in 2016 and beyond was approximately $261 million incorporating strip pricing as of February 29, 2016. We engage in derivative risk management activities in order to reduce the risk associated with commodity price fluctuations. Commodity hedges in place for 2016 will help mitigate some of the commodity price volatility and recent declines. The following table summarizes our commodity derivative contracts outstanding as of February 29, 2016:

	Fiscal Year Ending December 31,			
	2016	2017	2018	1H19
Oil, Natural Gas and NGL Swaps				
Oil (MBbl)	1,419	1,004	803	339
Natural Gas (MMcf)	16,470	12,300	10,240	4,410
Ethane (MBbl)	53	—	—	—
Propane (MBbl)	627	—	—	—
Iso Butane (MBbl)	76	7	—	—
Butane (MBbl)	218	17	—	—
Natural Gasoline (MBbl)	227	18	—	—
Total NGLs (MBbl)	1,201	42	—	—
Weighted Average Prices				
Oil ($ / Bbl)	$ 99.87	$ 80.01	$ 77.47	$64.65
Natural Gas ($ / Mcf)	$ 4.49	$ 4.29	$ 4.19	$ 3.53
Ethane ($ / Gal)	$ 0.21	—	—	—
Propane ($ / Gal)	$ 0.55	—	—	—
Iso Butane ($ / Gal)	$ 0.75	$ 1.42	—	—
Butane ($ / Gal)	$ 0.72	$ 1.37	—	—
Natural Gasoline ($ / Gal)	$ 1.46	$ 1.73	—	—

Sustained downward pressure on commodity prices has adverse effects on our business and financial position. Our ability to access capital markets may be restricted, which could have an impact on our flexibility to react to changing economic and business conditions. Further, the global oversupply situation could have an adverse impact on our business partners, customers and lenders, potentially causing them to fail to meet their obligations to us.

The amount of our proved reserves, as estimated based on SEC pricing and definitions, was 101.7 MMBoe as of December 31, 2015, of which 58% were classified as proved developed reserves. This decrease of approximately 12%, from 115.3 MMBoe as of December 31, 2014, was primarily due to the decline in commodity prices.

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.

Our 2015 capital expenditures totaled $200.1 million excluding the impact of asset retirement costs, of which $173.2 million was utilized to drill and complete operated wells. We currently plan to invest approximately $25.0 million in total capital expenditures in 2016, with the majority dedicated to workovers on existing wells and field optimization activities. We will continue to monitor market conditions and may decide at a later date to spend additional funds for a variety of opportunities which may include redeploying rigs to resume drilling activities or leasing. We are continuing to negotiate with vendors regarding service costs and do not plan on resuming its drilling program until well costs create acceptable rates of return at strip prices. Please see "Liquidity and Capital Resources." Assuming current market conditions and drilling success rates comparable to our historical performance, we believe we will be able to fund all of our 2016 budgeted capital expenditures with our cash flow from operations. Furthermore, 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. In order to accomplish this, our capital expenditure budgets in future years are expected to increase significantly as compared with the current 2016 budget.

In January and February 2016, through several open market and privately negotiated purchases, we purchased an aggregate principal amount of $170.5 million of our senior unsecured notes. As of February 29, 2016, we had purchased $70.5 million principal amount of our 2022 Notes for $27.1 million, and $100 million principal amount of our 2023 Notes for $46.5 million, in each case excluding accrued interest and including any associated fees. We used cash on hand and borrowings under our Revolver (as defined below) to fund the note purchases. As a result of these purchases, we had an aggregate principal amount of senior unsecured notes outstanding of $579.5 million, outstanding borrowings under our Revolver of $185 million, $325 million undrawn on our revolving credit facility, and $46 million in cash as of February 29, 2016. In conjunction with the extinguishment of this debt, JEH LLC recognized cancellation of debt income of $90.7 million on a pre-tax basis.

We may from time to time repurchase additional debt securities for cash and/or through exchanges for other securities. Such repurchases or exchanges may be made in the open market, in privately negotiated transactions, or otherwise. Any such repurchase or exchanges will depend on prevailing market conditions, our liquidity requirements, contractual restrictions, compliance with securities laws, and other factors.

We are not drilling new wells at this time, which limits our planned capital spending to approximately $25.0 million. As a result of this, our tax deductions associated with intangible drilling costs would be significantly lower, reducing our ability to offset our taxable income. Further, considering the recognition of income associated with debt extinguishment by JEH, described above, we are likely to be allocated taxable income in excess of any such tax deductions relating to 2016. 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.

Based on our 2016 budget and debt extinguishment through February 29, 2016, we estimate that the amount of tax distributions to JEH unitholders (other than us), plus the amount of our cash tax liabilities, in 2016 would be approximately $38.3 million based on information available as of this filing. Estimating the tax distributions required under the operating agreement is imprecise by nature, highly uncertain, and dependent upon a variety of factors. Additional debt extinguishment during the remainder of 2016 would increase the amount of potential tax distributions to JEH unitholders (other than us) and the amount of our cash tax liabilities, whereas a decision to deploy capital to drill new wells would decrease the amount of any potential tax distributions and liabilities.

Basis of Presentation

We consider and report all of our operations as one segment.

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 revenues when the product is delivered at a fixed or determinable price, title has transferred and collectability is reasonably assured and evidenced by a contract. 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.

Hedging

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. This eliminates potential margin calls in execution and limits our credit exposure to these particular lenders. 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. During the year ended December 31, 2015, 81% of our total production for oil, natural gas and NGLs was hedged. As of December 31, 2015, approximately 55% of our total forecasted production from proved reserves through 2017 was hedged, and the market value of our hedge position was $217.5 million. We do not anticipate any substantial changes in our hedging policy.

Our open positions as of December 31, 2015 were as follows:

	Year Ending December 31,				
	2016	2017	2018	2019	2020
Oil positions(1):					
Swaps:					
Hedged volume (MBbl)	1,897	1,040	803	339	—
Weighted average price ($/Bbl)	$ 82.74	$ 78.69	$ 77.47	$64.65	—
Natural gas positions(2):					
Swaps:					
Hedged volume (MMcf)	16,850	12,300	10,240	4,410	—
Weighted average price ($/Mcf)	$ 4.44	$ 4.29	$ 4.19	$ 3.53	—
NGL positions(3):					
Swaps:					
Hedged volume (MBbl)	1,201	42	—	—	—
Weighted average price ($/gal)	$ 0.75	$ 1.53	—	—	—
Natural Gas Basis positions(4):					
Swaps:					
Hedged volume (MMcf)	16,330	—	—	—	—
Weighted average price ($/Mcf)	$ (0.18)	—	—	—	—

(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.

(3) The NGL derivatives are settled based on the month's average daily price of Mont Belvieu and Conway ethane, propane, isobutane, butane and natural gasoline.

(4) The basis swap derivatives are settled based on the differential between the NYMEX natural gas futures price and the ANR Pipeline Co. Oklahoma price, the CenterPoint Energy Gas Transmission Co. East price, the Natural Gas Pipeline Co. of America Texok zone price, the Northern Natural Gas Co. demarcation price or the Panhandle Eastern Pipe Line Co. Texas/ Oklahoma price.

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.

Exploration. Exploration expense consists of geological and geophysical costs, seismic costs, amortization of unproved leasehold costs, and the costs to drill exploratory wells that do not find proved reserves.

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 pipelines 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 our senior secured revolving credit facility and senior notes. We incur interest expense that is affected by both fluctuations in interest rates and our financing decisions.

Results of Operations

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

(in thousands of dollars except for production, sales price and average cost data)	Years Ended December 31,			Years Ended December 31,		
	2015	2014	Change	2014	2013	Change
Revenues:						
Oil	$ 114,029	$220,090	$(106,061)	$220,090	$145,146	$ 74,944
Natural gas	45,558	82,947	(37,389)	82,947	55,511	27,436
NGLs	34,968	75,364	(40,396)	75,364	57,406	17,958
Total oil and gas	194,555	378,401	(183,846)	378,401	258,063	120,338
Other	2,844	2,196	648	2,196	1,106	1,090
Total operating revenues	197,399	380,597	(183,198)	380,597	259,169	121,428
Costs and expenses:						
Lease operating	41,027	37,760	3,267	37,760	25,129	12,631
Production taxes	12,130	22,556	(10,426)	22,556	15,517	7,039
Exploration	6,551	3,453	3,098	3,453	16,125	(12,672)
Depletion, depreciation and amortization	205,498	181,669	23,829	181,669	114,136	67,533
Accretion of ARO liability	1,087	770	317	770	608	162
General and administrative	33,388	25,763	7,625	25,763	31,902	(6,139)
Other operating	4,188	—	4,188	—	—	—
Total costs and expenses	303,869	271,971	31,898	271,971	203,417	68,554
Operating income (loss)	(106,470)	108,626	(215,096)	108,626	55,752	52,874
Other income (expenses):						
Interest expense	(61,289)	(38,805)	(22,484)	(38,805)	(27,409)	(11,396)
Net gain (loss) on commodity derivatives	158,753	189,641	(30,888)	189,641	(2,566)	192,207
Other income (expense)	(2,852)	(7,624)	4,772	(7,624)	(3,443)	(4,181)
Total other income (expense)	94,612	143,212	(48,600)	143,212	(33,418)	176,630
Income (loss) before income tax	(11,858)	251,838	(263,696)	251,838	22,334	229,504
Income tax provision (benefit)	(2,781)	26,218	(28,999)	26,218	(71)	26,289
Net income (loss)	(9,077)	225,620	(234,697)	225,620	22,405	203,215
Net income attributable to non-controlling interests	(6,696)	184,484	(191,180)	184,484	24,591	159,893
Net income (loss) attributable to controlling interests	$ (2,381)	$ 41,136	$ (43,517)	$ 41,136	$ (2,186)	$ 43,322
Net production volumes:						
Oil (MBbls)	2,583	2,475	108	2,475	1,557	918
Natural gas (MMcf)	23,839	21,922	1,917	21,922	17,575	4,347
NGLs (MBbls)	2,618	2,345	273	2,345	1,724	621
Total (MBoe)	9,174	8,474	701	8,474	6,210	2,264
Average net (Boe/d)	25,134	23,216	1,918	23,216	17,014	6,202
Average sales price, unhedged:						
Oil (per Bbl), unhedged	$ 44.15	$ 88.93	$ (44.78)	$ 88.93	$ 93.22	$ (4.29)
Natural gas (per Mcf), unhedged	1.91	3.78	(1.87)	3.78	3.16	0.62
NGLs (per Bbl), unhedged	13.36	32.14	(18.78)	32.14	33.30	(1.16)
Combined (per Boe), unhedged	21.21	44.65	(23.44)	44.65	41.56	3.09
Average sales price, hedged:						
Oil (per Bbl), hedged	$ 76.35	$ 88.16	$ (11.81)	$ 88.16	$ 87.86	$ 0.30
Natural gas (per Mcf), hedged	3.35	4.02	(0.67)	4.02	3.93	0.09
NGLs (per Bbl), hedged	25.73	32.60	(6.87)	32.60	33.26	(0.66)
Combined (per Boe), hedged	37.54	45.18	(7.64)	45.18	42.40	2.78
Average costs (per BOE):						
Lease operating	$ 4.47	$ 4.46	$ 0.01	$ 4.46	$ 4.05	$ 0.41
Production and ad valorem taxes	1.32	2.66	(1.34)	2.66	2.50	0.16
Depletion, depreciation and amortization	22.40	21.44	0.96	21.44	18.38	3.06
General and administrative	3.64	3.04	0.60	3.04	5.14	(2.10)

Results of Operations—Year ended December 31, 2015 as compared to year ended December 31, 2014

Operating revenues

Oil and gas sales. Oil and gas sales decreased by $183.8 million (48.6%) to $194.6 million for the year ended December 31, 2015, as compared to $378.4 million for the year ended December 31, 2014. The decrease was attributable to the decline in commodity prices ($195.9 million), partially offset by increased production volumes ($12.1 million). The average realized oil price, excluding the effects of commodity derivative instruments, decreased from $88.93 per Bbl to $44.15 per Bbl, or 50.4%, year over year. The average realized natural gas price, excluding the effects of commodity derivative instruments, decreased from $3.78 per Mcf to $1.91 per Mcf, or 49.5%, year over year. The average realized natural gas liquids price, excluding the effects of commodity derivative instruments, decreased from $32.14 per Bbl to $13.36 per Bbl, or 58.4%, year over year. Average daily production increased 8.3% to 25,134 Boe per day for the year ended December 31, 2015 as compared to 23,216 Boe per day for the year ended December 31, 2014. Crude oil production increased 4.4% from 2,475 MBbls for the year ended December 31, 2014 to 2,583 MBbls for the year ended December 31, 2015. Natural gas production increased 8.7% from 21,922 MMcf for the year ended December 31, 2014 to 23,839 MMcf for the year ended December 31, 2015. The increase in production was driven by the year-over-year increase in producing wells due to continued drilling activity through the third quarter, as well as changes in completion techniques.

Costs and expenses

Lease operating. Lease operating expense increased by $3.2 million (8.5%) to $41.0 million for the year ended December 31, 2015, as compared to $37.8 million for the year ended December 31, 2014. The increase occurred primarily in correlation with the 8.3% increase in production volumes and number of producing wells. On a per unit basis, lease operating expense increased by $0.01 per Boe or 0.2%, from $4.46 for the year ended December 31, 2014 to $4.47 per Boe, as compared to the year ended December 31, 2015.

Production and ad valorem taxes. Production and ad valorem taxes decreased by $10.5 million (46.5%) to $12.1 million for the year ended December 31, 2015, as compared to $22.6 million for the year ended December 31, 2014. Overall production and ad valorem taxes decreased in conjunction with the 48.6% decrease in oil and gas revenue. Estimated ad valorem taxes accounted for $2.5 million of the decrease from $6.1 million for the year ended December 31, 2014 to $3.6 million for the year ended December 31, 2015, reflecting lower property assessments due to lower commodity prices. The average effective rate excluding the impact of ad valorem taxes remained consistent at 4.4% for the years ended December 31, 2014 and 2015. 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.

Exploration. Exploration expense increased from $3.5 million for the year ended December 31, 2014 to $6.6 million for the year ended December 31, 2015. In 2015, the Company recognized charges for lease abandonment of $5.3 million relating to certain leases that the Company does not plan to develop. In 2014, the Company recognized the drilling cost of $3.0 million associated with an unsuccessful exploratory well. The remaining spend during 2015 primarily related to geological data and seismic processing associated with unproved acreage.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $23.8 million (13.1%) to $205.5 million for the year ended December 31, 2015, as compared to $181.7 million for the year ended December 31, 2014. The increase was primarily the result of continued drilling activity. On a per unit basis, depletion expense increased $0.96 per Boe or 4.5% to

$22.40 per Boe for the year ended December 31, 2015 as compared to $21.44 per Boe for the year ended December 31, 2014.

General and administrative. General and administrative expenses increased by $7.6 million (29.5%) to $33.4 million for the year ended December 31, 2015, as compared to $25.8 million for the year ended December 31, 2014. Contributing to the change was an increase of $3.2 million related to non-cash compensation expense. Excluding these non-cash items, general and administrative expenses increased $4.4 million (21.0%) to $25.4 million for the year ended December 31, 2015, as compared to $21.0 million for the year ended December 31, 2014. The increase in cash general and administrative expense was primarily attributable to a 12% increase in headcount year-over-year. The remainder of the increase was primarily attributable to increases in professional fees including higher accounting, legal and other fees associated with the Company's financing activities and status as a new public entity. On a per unit basis, cash general and administrative expenses increased from $2.47 per Boe for the year ended December 31, 2014 to $2.77 per Boe for the year ended December 31, 2015.

Other operating expense. Other operating expense of $4.2 million for the year ended December 31, 2015 represents stand-by rig costs associated with the charges assessed on early termination of drilling rig contracts. This is a non-recurring charge for which all costs have been recognized as of December 31, 2015.

Interest expense. Interest expense increased by $22.5 million (58.0%) to $61.3 million for the year ended December 31, 2015, as compared to $38.8 million for the year ended December 31, 2014. The increase was driven by the issuance of the 2022 Notes and 2023 Notes on April 1, 2014 and February 23, 2015, respectively. During the year ended December 31, 2015, borrowings under the Revolver, the 2022 Notes and the 2023 Notes bore interest at a weighted average rate of 2.39%, 6.75% and 9.25%, respectively. Average outstanding balances for the year ended December 31, 2015 were $144.9 million, $500.0 million and $213.7 million under the Revolver, the 2022 Notes and the 2023 Notes, respectively.

Gain (loss) on commodity derivatives. The gain (loss) on commodity derivatives was a net gain of $158.8 million for the year ended December 31, 2015. The gain was driven by lower average crude oil and natural gas prices ($48.66 per barrel and $2.62 per Mcf, respectively) for the year ended December 31, 2015, as compared to the crude oil and natural gas prices as of December 31, 2014 ($53.45 per barrel and $3.14 per Mcf, respectively) as well as additional hedging activity during 2015.

Other income (expense). Other income (expense) for the year ended December 31, 2015 was a net expense of $2.9 million. Financing costs resulted in expenses of $5.5 million primarily driven by amortization of capitalized loan costs, partially offset by the recognition of income associated with the establishment of a $2.0 million valuation allowance associated with the Tax Receivable Agreement (the "TRA") and by the receipt of a $0.7 million distribution of dividend income from our investment in Monarch Natural Gas Holdings, LLC. See Note 11, "Income Taxes—Tax Receivable Agreement," for further details regarding the TRA.

Income taxes. The provision for federal and state income taxes for the year ended December 31, 2015 was a benefit of $2.8 million as compared to an expense of $26.2 million for the year ended December 31, 2014. 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.

Results of Operations—Year ended December 31, 2014 as compared to year ended December 31, 2013

Operating revenues

Oil and gas sales. Oil and gas sales increased by $120.3 million (46.6%) to $378.4 million for the year ended December 31, 2014, as compared to $258.1 million for the year ended December 31, 2013. The majority of the increase (67.8%) was due to higher crude oil production volumes with the remainder of the increase being primarily attributable to higher natural gas and natural gas liquid production volumes. Average daily production increased 36.5% to 23,216 Boe per day for the year ended December 31, 2014 as compared to 17,014 Boe per day for the year ended December 31, 2013. Crude oil production increased 59.0% from 1,557 MBbls for the year ended December 31, 2013 to 2,475 MBbls for the year ended December 31, 2014, primarily resulting from the wells acquired from Sabine at the end of 2013, combined with an increase in the number of wells drilled in 2014. Natural gas production increased 24.7% from 17,575 MMcf for the year ended December 31, 2013 to 21,922 MMcf for the year ended December 31, 2014, due to new wells added through drilling and the acquisition of the Sabine wells. The average realized oil price, excluding the effects of commodity derivative instruments, decreased from $93.22 per Bbl to $88.93 per Bbl, or 4.6%, year over year. The average realized natural gas price, excluding the effects of commodity derivative instruments, increased from $3.16 per Mcf to $3.78 per Mcf, or 19.6%, year over year. The average realized natural gas liquids price, excluding the effects of commodity derivative instruments, decreased from $33.30 per Bbl to $32.14 per Bbl, or 3.5%, year over year.

Costs and expenses

Lease operating. Lease operating expense increased by $12.7 million (50.6%) to $37.8 million for the year ended December 31, 2014, as compared to $25.1 million for the year ended December 31, 2013. The increase occurred primarily in correlation with the 36.5% increase in production volumes. On a per unit basis, lease operating expense increased by $0.41 per Boe or 10.1%, from $4.05 to $4.46 per Boe, for the year ended December 31, 2014 as compared to the year ended December 31, 2013. On an overall basis, lease operating expense increased due to new wells coming on line and higher compressor and salt water disposal expenses associated with the new wells drilled and acquired from Sabine.

Production and ad valorem taxes. Production and ad valorem taxes increased by $7.1 million (45.8%) to $22.6 million for the year ended December 31, 2014, as compared to $15.5 million for the year ended December 31, 2013. Overall production and ad valorem taxes increased in conjunction with the 46.6% increase in revenue. Estimated ad valorem taxes accounted for $3.4 million of the increase from $2.7 million for the year ended December 31, 2013 to $6.1 million for the year ended December 31, 2014, due to new wells coming on line. The average effective rate excluding the impact of ad valorem taxes increased from 5.0% for the year ended December 31, 2013 to 4.4% for the year ended December 31, 2014. 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.

Exploration. Exploration expense decreased by $12.6 million from $16.1 million for the year ended December 31, 2013 to $3.5 million for the year ended December 31, 2014. In 2014, costs related to a dry hole as the Company drilled an unsuccessful exploratory well. In 2013, the Company recognized charges for lease abandonment of $14.4 million relating to certain leases, unproved Southridge properties, that the Company did not plan to develop.

Depreciation, depletion and amortization. Depreciation, depletion and amortization increased by $67.6 million (59.2%) to $181.7 million for the year ended December 31, 2014, as compared to $114.1 million for the year ended December 31, 2013. The increase was primarily the result of continued drilling activity and the acquisition of the Sabine wells at the end of 2013. On a per unit basis, depletion expense increased $3.06 per Boe or 16.6% to $21.44 per Boe for the year ended December 31, 2014 as compared to $18.38 per Boe for the year ended December 31, 2013. The per unit increase resulted from the higher cost to drill wells in 2014 compared to historical wells.

General and administrative. General and administrative expenses decreased by $6.1 million (19.1%) to $25.8 million for the year ended December 31, 2014, as compared to $31.9 million for the year ended December 31, 2013. A decrease of $6.8 million related to stock compensation expense (of which $9.6 million related to the immediate vesting of certain shares on the IPO date in 2013, offset by $2.0 million of expense related to new incentive awards in 2014) and $2.4 million related to a one-time non-cash distribution in 2013 to management related to the Monarch incentive plan. Excluding these non-cash items, general and administrative expenses increased $2.7 million (14.7%) to $21.0 million for the year ended December 31, 2014, as compared to $18.3 million for the year ended December 31, 2013. The increase in cash general and administrative expense is attributable to an increase in personnel costs and office expense due to an increase in headcount to support our increased drilling activity. On a per unit basis, cash general and administrative expenses decreased from $2.95 per Boe for the year ended December 31, 2013 to $2.47 per Boe for the year ended December 31, 2014. The increase in activity resulting from drilling and the acquisition of the Sabine properties significantly increased production (36.5% on a Boe basis) but did not result in a proportional increase in general and administrative expenses.

Interest expense. Interest expense increased by $11.4 million (41.6%) to $38.8 million for the year ended December 31, 2014, as compared to $27.4 million for the year ended December 31, 2013. The increase was driven by the issuance of the 2022 Notes on April 1, 2014. During the year ended December 31, 2014, borrowings under the Revolver, the second lien term loan and the 2022 Notes bore interest at a weighted average rate of 2.51%, 9.13% and 6.75%, respectively. Average outstanding balances for the year ended December 31, 2014 were $333.8 million, $39.5 million and $376.7 million under the Revolver, the second lien term loan and the 2022 Notes, respectively.

Gain (loss) on commodity derivatives. The gain (loss) on commodity derivatives was a net gain of $189.6 million for the year ended December 31, 2014. The gain was driven by lower average crude oil prices ($93.17 per barrel) for the year ended December 31, 2014, as compared to the crude oil prices as of December 31, 2013 ($98.17 per barrel). This was partially offset by higher average natural gas prices ($4.37 per Mcf) for the year ended December 31, 2014, as compared to the natural gas price as of December 31, 2013 ($4.31 per Mcf).

Other income (expense). Other income (expense) was a loss of $7.6 million for the year ended December 31, 2014, compared to a loss of $3.4 million for the year ended December 31, 2013. The increase of $4.2 million (123.5%) was driven by increased financing costs.

Income taxes. The provision for income taxes reflects our reorganization and recapitalization which occurred in connection with the Company's initial public offering. Following the IPO in July 2013, the Company is subject to federal and state income and franchise taxes, while only the Texas franchise tax applied to JEH prior to the IPO. Income tax expense was an expense of $26.2 million for the year ended December 31, 2014 compared to a benefit of $0.1 million for the year ended December 31, 2013. 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.

Liquidity and Capital Resources

Historically, our primary sources of liquidity have been private and public sales of our debt and equity, borrowings under bank credit facilities and cash flows from operations. Our primary use of capital has been for the exploration, development and acquisition of oil and gas properties. As we pursue reserves and production growth, we continually consider which capital resources, including equity and debt financings, are available to meet our future financial obligations, planned capital expenditure activities and liquidity requirements. Our ability to grow proved reserves and production will be highly dependent on the capital resources available to us. We strive to maintain financial flexibility in order to maintain substantial borrowing capacity under our Revolver (as defined below), facilitate drilling on our undeveloped acreage positions and permit us to selectively expand our acreage positions. Depending on the timing and concentration of the development of our non-proved locations, we may be required to generate or raise significant amounts of capital to develop all of our potential drilling locations should we endeavor to do so. In the event our cash flows are materially less than anticipated and other sources of capital we historically have utilized are not available on acceptable terms, we may curtail our capital spending. Our balance sheet at December 31, 2015 reflects a positive working capital balance largely due to the value of our current commodity derivative assets as of year-end. We have historically and in the future expect to maintain a negative working capital balance, and we use our Revolver to help manage our working capital.

Availability under the Revolver is subject to a borrowing base. Our borrowing base at December 31, 2015 was $510 million of which $110 million was utilized leaving an unused capacity of $400 million. The borrowing base will be redetermined at least semi-annually on or about April 1 and October 1 of each year, with such redetermination based primarily on reserve reports using lender commodity price expectations at such time. In light of current commodity prices, it is our expectation that the borrowing base will be reduced during the upcoming redetermination. Any reduction in the borrowing base will reduce our liquidity, and, if the reduction results in the outstanding amount under our Revolver exceeding the borrowing base, we will be required to repay the deficiency within a short period of time.

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

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

- a total leverage ratio, consisting of consolidated debt to EBITDAX, of not greater than 4.00 to 1.00 as of the last day of any fiscal quarter; and
- a current ratio, consisting of consolidated current assets, including the unused amounts of the total commitments, to consolidated current liabilities, of not less than 1.0 to 1.0 as of the last day of any fiscal quarter.

As of December 31, 2015, our total leverage ratio is approximately 3.2 and our current ratio is approximately 6.9, as calculated based on the requirements in our covenants. We believe that we are in compliance with all terms of our Revolver and expect to maintain compliance during 2016. However, factors including those outside of our control, such as commodity price declines, may prevent us from maintaining compliance with these covenants, at future measurement dates in 2016 and beyond. In the event it were to became necessary, we believe we have the ability to take actions that would prevent us from failing to comply with our covenants, such as hedge restructuring. While it is our expectation that we will continue to be in compliance with our covenants, no assurance can be given that this will be the case. If an event of default exists under the Revolver, the lenders will be able to accelerate the obligations outstanding under the Revolver and exercise other rights and remedies. Our Revolver contains customary events of default, including the occurrence of a change of control, as defined in the Revolver.

As we do not plan on resuming drilling activities until well costs create acceptable rates of return at strip prices, our 2016 capital budget will be primarily focused on workovers of existing wells and field optimization activities. The amount of capital we expend may fluctuate materially based on the market conditions for commodity prices and costs of drilling and completing wells, the economic returns being realized and the success of our drilling results as the year progresses. We expect to fund our entire 2016 capital budget with cash flows from operations and borrowings under our Revolver. If necessary, we may also access capital through proceeds from potential asset dispositions and the future issuance of debt and/or equity securities.

The amount, timing and allocation of capital expenditures are largely discretionary and within management's control. If oil and gas prices decline to levels below our acceptable levels or costs increase to levels above our acceptable levels, we may choose to defer a portion of our budgeted capital expenditures until later periods in order to achieve the desired balance between sources and uses of liquidity and to prioritize capital projects that we believe have the highest expected returns and potential to generate near-term cash flow. For example, due to the steep reduction of commodity prices experienced in the fourth quarter of 2014, we reduced our capital budget for 2015 to $210 million and have further reduced our capital budget to $25 million in 2016. We may also increase our capital expenditures significantly to take advantage of opportunities we consider to be attractive. We continuously monitor and adjust our projected capital expenditures in response to success or lack of success in drilling activities, changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the availability of rigs, contractual obligations, internally generated cash flow and other factors both within and outside our control.

The following table summarizes our cash flows for the years ended December 31, 2015, 2014 and 2013:

	Year Ended December 31,		
(in thousands of dollars)	**2015**	**2014**	**2013**
Net cash provided by operating activities	$ 69,030	$ 265,423	$ 148,573
Net cash used in investing activities	(168,401)	(463,903)	(368,277)
Net cash provided by financing activities	107,698	188,226	219,798
Net increase (decrease) in cash	$ 8,327	$ (10,254)	$ 94

Cash Flow Provided by Operating Activities

Net cash provided by operating activities was $69.0 million for the year ended December 31, 2015 as compared to cash provided by operating activities of $265.4 million for the year ended December 31, 2014. The decrease in operating cash flows was primarily due to a $183.8 million decrease in oil and gas revenues for the year ended December 31, 2015 as compared to the year ended December 31, 2014. The decrease in revenue was attributable to the decline in commodity prices.

Net cash provided by operating activities was $265.4 million for the year ended December 31, 2014 as compared to cash provided by operating activities of $148.6 million for the year ended December 31, 2013. The increase in operating cash flows was primarily due to a $120.3 million increase in oil and gas revenues for the year ended December 31, 2014 as compared to the year ended December 31, 2013. The increase in revenue was primarily driven by a 59.0% increase in oil production volumes as a result of drilling and the acquisition of the Sabine wells in the fourth quarter of 2013, combined with increases in natural gas and NGL production volumes.

Our operating cash flows are sensitive to a number of variables, the most significant of which is 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 $168.4 million for the year ended December 31, 2015 as compared to cash used in investing activities of $463.9 million for the year ended December 31, 2014. The decrease was primarily driven by the reduction in capital expenditures which decreased $163.3 million during the year ended December 31, 2015 as compared to the year ended December 31, 2014 due to a decrease in drilling activity. Additionally, cash flows from current period settlements of our commodity derivative instruments resulted in net cash receipts of $144.1 million for the year ended December 31, 2014 as compared to net payments of $3.7 million for the year ended December 31, 2014 as a result of lower commodity prices.

Net cash used in investing activities was $463.9 million for the year ended December 31, 2014 as compared to cash used in investing activities of $368.3 million for the year ended December 31, 2013. The increase was primarily driven by higher capital expenditures which increased $277.0 million during the year ended December 31, 2014 as compared to the year ended December 31, 2013 due to an increase in drilling activity. The increase in capital expenditures was partially offset by the absence of acquisitions of property during 2014 as compared to the $178.2 million acquisition of the Sabine properties at the end of 2013. $15.7 million was refunded in 2014 after determining the final purchase price of the Sabine properties that were acquired in 2013. Additionally, cash flows from current period settlements of our commodity derivative instruments were net payments of $3.7 million for the year ended December 31, 2014 as compared to net receipts of $7.6 million for the year ended December 31, 2013 as a result of higher commodity prices that occurred early in the year 2014.

We expect our 2016 capital expenditures to be approximately $25.0 million, which is an 87.5% decrease from the $200.1 million incurred for 2015 excluding the impact of asset retirement costs. 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 a significant portion 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 $107.7 million for the year ended December 31, 2015 as compared to net cash provided by financing activities of $188.2 million for the year ended December 31, 2014. The decrease in cash flows provided by financing activities was primarily due to a $263.5 million reduction in proceeds from the issuance of senior notes. During 2015, we made net payment on our credit facility of $251.6 million as compared to net payments of $311.4 million during 2014.

Net cash provided by financing activities was $188.2 million for the year ended December 31, 2014 as compared to net cash provided by financing activities of $219.8 million for the year ended December 31, 2013. The decrease in cash flows provided by financing activities was primarily due to net payment on our credit facility of $311.4 million during 2014 as compared to net borrowing of $47.3 million during 2013. The net proceeds from the issuance of our senior notes of $490.0 million (net of expenses) in the second quarter of 2014 were used to repay borrowings under the credit facilities of $468 million during the year ended December 31, 2014.

Senior Notes due 2022

On April 1, 2014, JEH and Jones Energy Finance Corp., JEH's wholly-owned subsidiary formed for the sole purpose of co-issuing certain of JEH's debt (together the "Issuers"), sold $500.0 million in aggregate principal amount of the Issuers' 6.75% senior notes due 2022 (the "2022 Notes"). The Company used the net proceeds from the issuance of the 2022 Notes to repay all outstanding borrowings under the Term Loan ($160.0 million), a portion of the outstanding borrowings under the Revolver ($308.0 million) and for working capital and general corporate purposes. The Company subsequently terminated the Term Loan in accordance with its terms. The 2022 Notes bear interest at a rate of 6.75% per year, payable semi-annually on April 1 and October 1 of each year beginning October 1, 2014.

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

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

The indenture governing the 2022 Notes contains covenants that, among other things, limit our ability 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 our restricted subsidiaries to us, consolidate, merge or transfer all of our assets, engage in transactions with affiliates or create unrestricted subsidiaries. However, many of these covenants will be suspended if the 2022 Notes are rated investment grade by Standard & Poor's or Moody's.

Senior Notes due 2023

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

The 2023 Notes are guaranteed on a senior unsecured basis by us and by all of our existing significant subsidiaries. The 2023 Notes will be senior in right of payment to any future subordinated indebtedness of the Issuers.

We may redeem the 2023 Notes at any time on or after March 15, 2018 at a declining redemption price set forth in the indenture, plus accrued and unpaid interest.

The indenture governing the 2023 Notes contains covenants that, among other things, limit our ability 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 our restricted subsidiaries to us, consolidate, merge or transfer all of our assets, engage in transactions with affiliates or create unrestricted subsidiaries. However, many of these covenants will be suspended if the 2023 Notes are rated as investment grade by Standard & Poor's or Moody's.

Credit Facilities

Senior Secured Revolving Credit Facility. JEH has a $1 billion senior secured revolving credit facility (the "Revolver") with Wells Fargo Bank, N.A. as the administrative agent, and a syndicate of lenders. Availability under the Revolver is subject to a borrowing base, which is currently $510 million. The Revolver matures in November 2019. As of December 31, 2015, JEH had borrowings of $110 million outstanding under the Revolver. JEH's obligations under the Revolver are guaranteed by us and JEH's subsidiaries and are secured by substantially all of their assets (other than equity interests of JEH held by us).

On November 6, 2014, JEH entered into a ninth amendment (the "Ninth Amendment") to the Revolver. The Ninth Amendment amended the Revolver to, among other things, (1) increase the borrowing base under the Revolver from $550 million to $625 million, and (2) extend the maturity date of the Revolver to November 6, 2019. The foregoing description of the Ninth Amendment is not complete and is qualified by reference to the complete document, which is filed as Exhibit 10.22 to this Annual Report and is incorporated herein by reference.

The borrowing base under our Revolver will be redetermined at least semi- annually on or about April 1 and October 1 of each year. JEH and the administrative agent (acting at the direction of lenders holding at least 66⅔% of the outstanding loans) may each request one unscheduled borrowing base redetermination between each scheduled redetermination. In addition, the lenders may elect to redetermine the borrowing base upon the occurrence of certain defaults under our material operating agreements or upon the cancellation or termination of certain of our joint development agreements. The borrowing base may also be reduced as a result of our issuance of unsecured notes, our termination of material hedging positions or our consummation of significant asset sales.

If the aggregate outstanding principal amount of the revolving loans under the Revolver exceeds the borrowing base as a result of a scheduled or interim adjustment of the borrowing base, we must prepay revolving loans in an amount equal to such excess within 90 days following the date the adjustment occurs or the date we receive notice thereof (with at least one-half of the prepayment to be paid or deposited within 45 days following such date). However, if such a borrowing base deficiency results from a permitted disposition of oil and gas properties or from terminations or modifications of hedge positions, we must immediately make such prepayment and/or deposit of cash collateral. Otherwise, all unpaid principal and interest is due at maturity.

Interest on loans under our Revolver is calculated, at JEH's option, at either (i) the LIBO Rate for the applicable interest period plus a margin ranging from 1.50% to 2.50% based on the level of borrowing base utilization at such time or (ii) the greatest of (x) the prime rate announced by Wells Fargo Bank, N.A. in effect on such day, (y) the federal funds rate plus 0.50% and (z) the one-month adjusted LIBO Rate plus 1.00%, plus a margin ranging from 0.50% to 1.50% based on the level of borrowing base utilization at such time. JEH is also required to pay a quarterly commitment fee on the unused portion of the aggregate commitments of the lenders, at a rate per annum of either 0.375% or 0.50%, depending on our utilization of the borrowing base.

The Revolver contains various covenants that, among other things, limit our ability to:

- incur indebtedness;
- grant liens on our assets;
- pay dividends or distributions or redeem any of our equity interests;
- make certain investments, loans and advances;
- merge into or with or consolidate with any other person, or dispose of all or substantially all of our property to any other person;

- engage in certain asset dispositions;
- enter into transactions with affiliates;
- grant negative pledges or agree to restrict dividends or distributions from subsidiaries;
- allow gas imbalances, take-or-pay or certain other prepayments with respect to oil and gas properties; and
- enter into certain derivative arrangements.

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

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

- a total leverage ratio, consisting of consolidated debt to EBITDAX, of not greater than 4.00 to 1.00 as of the last day of any fiscal quarter; and
- a current ratio, consisting of consolidated current assets, including the unused amounts of the total commitments, to consolidated current liabilities, of not less than 1.0 to 1.0 as of the last day of any fiscal quarter.

We believe that we are in compliance with the terms of our Revolver. If an event of default exists under the Revolver, the lenders will be able to accelerate the obligations outstanding under the Revolver and exercise other rights and remedies. Our Revolver contains customary events of default, including the occurrence of a change of control, as defined in the Revolver.

Second Lien Term Loan Facility. Prior to the issuance of the 2022 Notes JEH had a $160 million second lien term loan facility (the "Term Loan") with Wells Fargo Energy Capital, Inc., as the administrative agent, and a syndicate of lenders. All outstanding borrowings on the Term Loan were repaid using a portion of the proceeds obtained from issuing the 2022 Notes in the second quarter 2014. The Company subsequently terminated the Term Loan in accordance with its terms.

Off-Balance Sheet Arrangements

At December 31, 2015, we did not have any off-balance sheet arrangements.

Contractual Obligations

The following table summarizes our contractual obligations as of December 31, 2015:

(dollars in thousands of dollars)	Payments Due by Period Total	Less than 1 Year	1 - 3 Years	4 - 5 Years	Thereafter
Long-term debt obligations	$ 860,000	$ —	$110,000	$ —	$750,000
Interest expense(1)	386,273	59,504	178,116	113,750	34,903
Commodity derivative obligations	11	11	—	—	—
Operating lease obligations	4,583	945	3,261	377	—
Total	$1,250,867	$60,460	$291,377	$114,127	$784,903

(1) Interest expense is estimated based on the outstanding balance at December 31, 2015 multiplied by the weighted average interest rate during 2015.

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.

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. Based on our 2016 budget and debt extinguishment through February 29, 2016, we estimate that the amount of tax distributions to JEH unitholders (other than us), plus the amount of our cash tax liabilities, in 2016 would be approximately $38.3 million based on information available as of this filing. 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 pre-IPO owners that provides for payment by Jones Energy, Inc. to exchanging pre-IPO owners of 85% of the benefits, if any, that Jones Energy, Inc. is deemed to realize as a result of any exchange. As a result of exchanges made prior to December 31, 2015, the Company recorded a TRA liability of $38.1 million. Estimating the timing of payments made under the Tax Receivable Agreement is imprecise by nature, highly uncertain, and dependent upon a variety of factors.

In the event we are allocated taxable income relating to 2016 from JEH, we are likely to make a payment of a portion of the TRA liability during 2017. 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.

Use of Estimates. The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the amounts of revenues and expenses reported for the period then ended.

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.

Unproved leasehold costs are assessed at least annually to determine whether they have been impaired. 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 7, "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.

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, 2015 was a net asset of $217.5 million.

As of December 31, 2015, we have hedged approximately 55% of our total forecasted production from proved reserves through December 31, 2017. 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, 2015 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 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. We are not permitted under the terms of the revolving credit facility to enter into derivative instruments with counterparties outside of the banks who are lenders under the revolving credit facility. As a result, any future derivative instruments will be with these or other lenders under the revolving credit facility who will also likely carry investment grade ratings.

Interest rate risk

We are subject to market risk exposure related to changes in interest rates on our variable rate indebtedness. The terms of the senior secured revolving credit facility provide for interest on borrowings at a floating rate equal to prime, LIBOR or federal funds rate plus margins ranging from 0.50% to 2.50% depending on the base rate used and the amount of the loan outstanding in relation to the borrowing base. The base rate margins under the terminated term loan were 6.0-7.0% depending on the base rate used and the amount of the loan outstanding. The terms of our senior notes provide for a fixed interest rate through their respective maturity dates. During the year ended December 31, 2015, borrowings under the Revolver, the 2022 Notes and the 2023 Notes bore interest at a weighted average rate of 2.39%, 6.75% and 9.25%, respectively.

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.

Based on this evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were not effective as of December 31, 2015 because our material weakness, identified at the time of our IPO, has not been fully remediated throughout the year ended December 31, 2015.

Management's Assessment of 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.

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

As of December 31, 2015, 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)*. Based on this assessment, management determined that, as of December 31, 2015, a material weakness related to design and execution of our controls continued to exist. Additionally, this material weakness could result in a misstatement of account balances or disclosures that would result in a material misstatement to the annual or interim consolidated financial statements that would not be prevented or detected. Because of this material weakness, management concluded that we did not maintain effective internal control over financial reporting as of December 31, 2015, based on the COSO criteria.

A material weakness is a deficiency, or combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements will not be prevented or detected on a timely basis.

Attestation Report of the Registered Public Accounting Firm

Pursuant to the JOBS Act, our independent registered public accounting firm will not be required to attest to the effectiveness of our internal control over financial reporting pursuant to Section 404 of

the Sarbanes-Oxley Act of 2002 for up to five years or through such earlier date that we are no longer an "emerging growth company" as defined in the JOBS Act.

Remediation steps to address the material weakness

The material weakness in our internal control over financial reporting was previously disclosed in Item 9A, *Controls and Procedures* of our Annual Report on Form 10-K for the years ended December 31, 2013 and December 31, 2014.

Management took steps during the years ended December 31, 2014 and 2015 to address the previously identified material weakness, including the implementation of new accounting processes and control procedures and the identification of gaps in our skills base and expertise of the staff required to meet the financial reporting requirements of a public company. We have strengthened our internal control environment through the addition of skilled accounting personnel. This team has enabled us to expedite our month-end close process, thereby facilitating the timely preparation of financial reports. We continue to hire incremental qualified staff, as needed, in conjunction with a comprehensive review of our internal controls and formalization of our review and approval processes.

The design and implementation of new accounting processes and control procedures, in conjunction with the staffing improvements, made progress toward remediation of the previously noted material weakness.

Shortly after the initial public offering, the Company engaged an independent accounting and consulting firm to fulfill its internal audit needs. The principal focus of the internal audit function has been to test the design and operating effectiveness of our controls. Based upon our testing and evaluation of the effectiveness of our internal controls, we have concluded we have designed but not fully implemented new processes and controls to remediate the material weakness identified as of December 31, 2015.

Changes in Internal Control over Financial Reporting

As described above under Remediation Steps to address the material weakness, there were changes in our internal control over financial reporting, relating to the quarter ended December 31, 2015 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

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.

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
2.1	Purchase and Sale Agreement by and between Chalker Energy Partners II, LLC, the listed participating owners and Jones Energy Holdings, LLC, dated November 28, 2012 (incorporated by reference to Exhibit 10.7 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on June 7, 2013).
2.2	Purchase and Sale Agreement by and between Sabine Mid-Continent LLC, as seller, and Jones Energy Holdings, LLC, as purchaser, dated as of November 22, 2013 (incorporated by reference to Exhibit 2.2 to the Company's Annual Report on Form 10-K filed on March 14, 2014).
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 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 on July 30, 2013).
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 on June 7, 2013).
4.2	Registration Rights and Stockholders Agreement, dated as of July 29, 2013 (incorporated by reference to Exhibit 10.5 to the Company's Current Report on Form 8-K filed on July 30, 2013).
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 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 on April 1, 2014).
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 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 on February 27, 2015).
10.1	Third Amended and Restated Limited Liability Company Agreement of Jones Energy Holdings, LLC (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on July 30, 2013).
10.2	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 on July 30, 2013).

Exhibit No.	Description
10.3	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 on July 30, 2013).
10.4†	Jones Energy, Inc. 2014 Omnibus Incentive Plan, effective as of July 29, 2013 (incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K filed on July 30, 2013).
10.5†	Jones Energy, Inc. Short Term Incentive Plan, effective as of July 29, 2013 (incorporated by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K filed on July 30, 2013).
10.6†	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 on September 4, 2013).
10.7†	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 on May 27, 2014).
10.8†	Form of Performance Unit Award Agreement (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on May 27, 2014).
10.9†	Jones Energy, LLC Executive Deferral Plan (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed on October 23, 2013).
10.10†	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).
10.11	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 on June 7, 2013).
10.12	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 on May 28, 2013).
10.13	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 on May 28, 2013).
10.14	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 on May 28, 2013).
10.15	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 on May 28, 2013).
10.16	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 on May 28, 2013).
10.17	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 on May 28, 2013).

Exhibit No.	Description
10.18	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 on May 28, 2013).
10.19	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 on June 17, 2013).
10.20	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 on March 14, 2014).
10.21	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 on March 14, 2014).
10.22*	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
10.23	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).
10.24	Second Lien Credit Agreement, dated as of December 31, 2009, among Jones Energy Holdings, LLC, as borrower, Wells Fargo Energy Capital, Inc., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.16 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on May 28, 2013).
10.25	Agreement and Amendment No. 1 to Second Lien Credit Agreement (incorporated by reference to Exhibit 10.17 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on May 28, 2013).
10.26	Agreement and Amendment No. 2 to Second Lien Credit Agreement (incorporated by reference to Exhibit 10.18 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on May 28, 2013).
10.27	Agreement and Amendment No. 3 to Second Lien Credit Agreement (incorporated by reference to Exhibit 10.19 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on May 28, 2013).
10.28	Agreement and Amendment No. 4 to Second Lien Credit Agreement (incorporated by reference to Exhibit 10.20 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on May 28, 2013).
10.29	Agreement and Amendment No. 5 to Second Lien Credit Agreement (incorporated by reference to Exhibit 10.21 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on May 28, 2013).

Exhibit No.	Description
10.30	Waiver and Amendment No. 6 to Second Lien Credit Agreement (incorporated by reference to Exhibit 10.22 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on May 28, 2013).
10.31	Waiver, Agreement and Amendment No. 7 to Second Lien Credit Agreement (incorporated by reference to Exhibit 10.25 to the Company's Registration Statement on Form S-1, File No. 333-188896, filed on June 17, 2013).
10.32	Firm Crude Oil Gathering and Transportation Agreement, dated September 26, 2014, by and between Monarch Oil Pipeline, LLC and Jones Energy, LLC (incorporated by reference to Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q filed on November 10, 2014).
10.33	Gathering and Transportation Services Agreement, dated as of September 26, 2014, by and between Monarch Oil Pipeline, LLC and Jones Energy, LLC (incorporated by reference to Exhibit 10.3 to the Company's Quarterly Report on Form 10-Q filed on November 10, 2014).
10.34*	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.
10.35*	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.
21.1*	List of Subsidiaries of Jones Energy, Inc.
23.1*	Consent of PricewaterhouseCoopers LLP.
23.2*	Consent of Cawley Gillespie & Associates, Inc.
31.1*	Rule 13a-14(a)/15d-14(a) Certification of Jonny Jones (Principal Executive Officer).
31.2*	Rule 13a-14(a)/15d-14(a) Certification of Robert J. Brooks (Principal Financial Officer).
32.1*	Section 1350 Certification of Jonny Jones (Principal Executive Officer).
32.2*	Section 1350 Certification of Robert J. Brooks (Principal Financial Officer).
99.1*	Summary Report of Cawley, Gillespie & Associates, Inc. for reserves as of December 31, 2015
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

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

SIGNATURES

Pursuant to the requirements of Section 13 or 14(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: March 9, 2016

By: /s/ JONNY JONES
Name: Jonny Jones
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 and Chief Executive Officer (Principal Executive Officer)	March 9, 2016
/s/ MIKE S. MCCONNELL Mike S. McConnell	Director and President	March 9, 2016
/s/ ROBERT J. BROOKS Robert J. Brooks	Executive Vice President and Chief Financial Officer (Principal Accounting and Financial Officer)	March 9, 2016
/s/ HOWARD I. HOFFEN Howard I. Hoffen	Director	March 9, 2016
/s/ GREGORY D. MYERS Gregory D. Myers	Director	March 9, 2016
/s/ HALBERT S. WASHBURN Halbert S. Washburn	Director	March 9, 2016
/s/ ALAN D. BELL Alan D. Bell	Director	March 9, 2016
/s/ ROBB L. VOYLES Robb L. Voyles	Director	March 9, 2016

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.

"***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 a 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.

"***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.

“***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.

Index to Financial Statements

Report of Independent Registered Public Accounting Firm F-2

Consolidated Financial Statements
Balance Sheets F-3
Statements of Operations F-4
Statement of Changes in Stockholders’ / Members’ Equity F-5
Statements of Cash Flows F-6
Notes to the Consolidated Financial Statements F-7
Supplemental Information on Oil and Gas Producing Activities (Unaudited) F-47
Supplemental Quarterly Financial Information (Unaudited) F-51

Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of operations, changes in stockholders' / members' equity, and cash flows present fairly, in all material respects, the financial position of Jones Energy, Inc. and its subsidiaries at December 31, 2015 and 2014 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
March 9, 2016

Jones Energy, Inc.
Consolidated Balance Sheets
December 31, 2015 and 2014

(in thousands of dollars)	December 31, 2015	December 31, 2014
Assets		
Current assets		
Cash	$ 21,893	$ 13,566
Restricted cash	330	149
Accounts receivable, net		
Oil and gas sales	19,292	51,482
Joint interest owners	11,314	41,761
Other	15,170	12,512
Commodity derivative assets	124,207	121,519
Other current assets	2,298	3,374
Total current assets	194,504	244,363
Oil and gas properties, net, at cost under the successful efforts method	1,635,766	1,638,860
Other property, plant and equipment, net	3,873	4,048
Commodity derivative assets	93,302	87,055
Other assets	17,967	20,352
Deferred tax assets	—	171
Total assets	$1,945,412	$1,994,849
Liabilities and Stockholders' Equity		
Current liabilities		
Trade accounts payable	$ 7,467	$ 136,337
Oil and gas sales payable	32,408	70,469
Accrued liabilities	27,341	19,401
Commodity derivative liabilities	11	—
Asset retirement obligations	679	3,074
Total current liabilities	67,906	229,281
Long-term debt	847,912	860,000
Deferred revenue	11,417	13,377
Commodity derivative liabilities	—	28
Asset retirement obligations	20,301	10,536
Liability under tax receivable agreement	38,052	803
Deferred tax liabilities	22,972	27,474
Total liabilities	1,008,560	1,141,499
Commitments and contingencies (Note 14)		
Stockholders' equity		
Class A common stock, $0.001 par value; 30,573,509 shares issued and 30,550,907 shares outstanding at December 31, 2015 and 12,672,260 shares issued and 12,649,658 shares outstanding at December 31, 2014	31	13
Class B common stock, $0.001 par value; 31,273,130 shares issued and outstanding at December 31, 2015 and 36,719,499 shares issued and outstanding at December 31, 2014	31	37
Treasury stock, at cost; 22,602 shares at December 31, 2015 and December 31, 2014	(358)	(358)
Additional paid-in-capital	363,723	178,763
Retained earnings (deficit)	36,569	38,950
Stockholders' equity	399,996	217,405
Non-controlling interest	536,856	635,945
Total stockholders' equity	936,852	853,350
Total liabilities and stockholders' equity	$1,945,412	$1,994,849

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

Jones Energy, Inc.
Consolidated Statements of Operations
Years Ended December 31, 2015, 2014 and 2013

(in thousands except per share data)	Year Ended December 31, 2015	2014	2013
Operating revenues			
Oil and gas sales	$ 194,555	$378,401	$258,063
Other revenues	2,844	2,196	1,106
Total operating revenues	197,399	380,597	259,169
Operating costs and expenses			
Lease operating	41,027	37,760	25,129
Production taxes	12,130	22,556	15,517
Exploration	6,551	3,453	16,125
Depletion, depreciation and amortization	205,498	181,669	114,136
Accretion of ARO liability	1,087	770	608
General and administrative	33,388	25,763	31,902
Other operating	4,188	—	—
Total operating expenses	303,869	271,971	203,417
Operating income (loss)	(106,470)	108,626	55,752
Other income (expense)			
Interest expense	(61,289)	(38,805)	(27,409)
Net gain (loss) on commodity derivatives	158,753	189,641	(2,566)
Other income (expense)	(2,852)	(7,624)	(3,443)
Other income (expense), net	94,612	143,212	(33,418)
Income (loss) before income tax	(11,858)	251,838	22,334
Income tax provision (benefit)			
Current	113	53	85
Deferred	(2,894)	26,165	(156)
Total income tax provision (benefit)	(2,781)	26,218	(71)
Net income (loss)	(9,077)	225,620	22,405
Net income (loss) attributable to non-controlling interests	(6,696)	184,484	24,591
Net income (loss) attributable to controlling interests	$ (2,381)	$ 41,136	$ (2,186)
Earnings (Loss) per share:			
Basic	$ (0.09)	$ 3.28	$ (0.17)
Diluted	$ (0.09)	$ 3.28	$ (0.17)
Weighted average shares outstanding:			
Basic	26,816	12,526	12,500
Diluted	26,816	12,535	12,500

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

Jones Energy, Inc.
Statement of Changes in Stockholders' / Members' Equity
Years Ended December 31, 2015, 2014 and 2013

(amounts in thousands)	Common Stock Class A Shares	Common Stock Class A Value	Common Stock Class B Shares	Common Stock Class B Value	Treasury Stock Class A Shares	Treasury Stock Class A Value	Members' Equity	Additional Paid-in Capital	Retained (Deficit)/ Earnings	Non-controlling Interest	Total Stockholders' / Members' Equity
Balance at December 31, 2012	—	$—	—	$—	—	$ —	$ 428,400	$ —	$ —	$ —	$428,400
Sale of common stock	12,500	13	36,836	37	—	—	—	172,431	—	—	172,481
Reclassification of members' contributions	—	—	—	—	—	—	(464,037)	—	—	464,037	—
Stock-compensation expense	—	—	—	—	—	—	10,100	738	—	—	10,838
Distribution to members	—	—	—	—	—	—	(10,000)	—	—	—	(10,000)
Net income (loss)	—	—	—	—	—	—	35,537	—	(2,186)	(10,946)	22,405
Balance at December 31, 2013	12,500	13	36,836	37	—	—	—	173,169	(2,186)	453,091	624,124
Treasury stock	(23)	—	—	—	23	(358)	—	—	—	—	(358)
Exchange of Class B shares for Class A shares	117	—	(117)	—	—	—	—	1,554	—	(1,630)	(76)
Stock-compensation expense	—	—	—	—	—	—	—	4,040	—	—	4,040
Vested restricted shares	28	—	—	—	—	—	—	—	—	—	—
Net income (loss)	—	—	—	—	—	—	—	—	41,136	184,484	225,620
Balance at December 31, 2014	12,622	13	36,719	37	23	(358)	—	178,763	38,950	635,945	853,350
Sale of common stock	12,263	12	—	—	—	—	—	123,189	—	—	123,201
Exchange of Class B shares for Class A shares	5,446	6	(5,446)	(6)	—	—	—	54,209	—	(92,393)	(38,184)
Stock-compensation expense	67	—	—	—	—	—	—	7,562	—	—	7,562
Vested restricted shares	153	—	—	—	—	—	—	—	—	—	—
Net income (loss)	—	—	—	—	—	—	—	—	(2,381)	(6,696)	(9,077)
Balance at December 31, 2015	30,551	$31	31,273	$31	23	$(358)	$ —	$363,723	$36,569	$536,856	$936,852

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

Jones Energy, Inc.

Consolidated Statements of Cash Flows

Years Ended December 31, 2015, 2014 and 2013

(in thousands of dollars)	Year Ended December 31, 2015	2014	2013
Cash flows from operating activities			
Net income (loss)	$ (9,077)	$ 225,620	$ 22,405
Adjustments to reconcile net income (loss) to net cash provided by operating activities			
Depletion, depreciation, and amortization	205,498	181,669	114,136
Exploration expense	5,250	2,952	14,415
Accretion of ARO liability	1,087	770	608
Amortization of debt issuance costs	6,043	6,878	2,677
Stock compensation expense	7,562	4,040	10,838
Other non-cash compensation expense	455	758	2,719
Amortization of deferred revenue	(1,960)	(1,154)	(469)
(Gain) loss on commodity derivatives	(158,753)	(189,641)	2,566
(Gain) loss on sales of assets	3	(297)	78
Deferred income tax provision	(2,892)	26,165	(156)
Other—net	(961)	376	79
Changes in assets and liabilities			
Accounts receivable	64,510	(2,453)	(56,804)
Other assets	(251)	(565)	163
Accrued interest expense	7,050	7,823	1,891
Accounts payable and accrued liabilities	(54,534)	2,482	33,427
Net cash provided by operations	69,030	265,423	148,573
Cash flows from investing activities			
Additions to oil and gas properties	(311,305)	(474,619)	(197,618)
Acquisition of properties	—	—	(178,173)
Net adjustments to purchase price of properties acquired	—	15,709	—
Proceeds from sales of assets	41	448	1,607
Acquisition of other property, plant and equipment	(1,101)	(1,683)	(1,634)
Current period settlements of matured derivative contracts	144,145	(3,654)	7,586
Change in restricted cash	(181)	(104)	(45)
Net cash used in investing	(168,401)	(463,903)	(368,277)
Cash flows from financing activities			
Proceeds from issuance of long-term debt	85,000	170,000	220,000
Repayment under long-term debt	(335,000)	(468,000)	(172,000)
Proceeds from senior notes	236,475	500,000	—
Payment of debt issuance costs	(1,556)	(13,416)	(683)
Proceeds from sale of common stock	122,779	—	172,481
Purchase of treasury stock	—	(358)	—
Net cash provided by financing	107,698	188,226	219,798
Net increase (decrease) in cash	8,327	(10,254)	94
Cash			
Beginning of period	13,566	23,820	23,726
End of period	$ 21,893	$ 13,566	$ 23,820
Supplemental disclosure of cash flow information			
Cash paid for interest	$ 52,796	$ 29,560	$ 25,414
Cash paid for income taxes	(155)	155	—
Change in accrued additions to oil and gas properties	(111,210)	49,025	41,945
Current additions to ARO	6,349	1,995	1,516

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

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 and through private equity funds managed by Metalmark Capital and Wells Fargo Energy Capital (collectively, the "Pre-IPO owners"). JEH acts as a holding company of operating subsidiaries that own and operate assets that are used in the exploration, development, production and acquisition of oil and natural gas properties.

The Company's certificate of incorporation authorizes two classes of common stock, Class A common stock and Class B common stock. The Class B common stock is held by the owners of JEH prior to the Company's initial public offering ("IPO") and can be exchanged (together with a corresponding number of units representing membership interests in JEH ("JEH Units")) for shares of Class A common stock on a one-for-one basis, subject to customary conversion rate adjustments for stock splits, stock dividends and reclassifications and other similar transactions. The Class B common stock has no economic rights but entitles its holders to one vote on all matters to be voted on by the Company's stockholders generally. As a result of the IPO and as of February 29, 2016, the Pre-IPO owners had 74.7% and 50.6%, respectively, of the total economic interest in JEH, but with no voting rights or management power over JEH, resulting in the Company reporting this ownership interest as a non-controlling interest. Prior to the IPO, JEH owned the controlling interest in the Company; hence all of the net income earned prior to the IPO date is reflected in the net income attributable to non-controlling interests on the Consolidated Statement of Operations for the year ended December 31, 2013.

Description of Business

The Company is engaged in the exploration, development, production and acquisition of oil and natural gas properties in the mid-continent United States. The Company's assets are located within the Anadarko and Arkoma basins of Texas and Oklahoma, and are owned by JEH and its operating subsidiaries. The Company is headquartered in Austin, Texas.

Revision of Previously Issued Financial Statements

During the first quarter of 2015, we identified an error in our previously issued Form 10-K for the year ended December 31, 2014 related to the over accrual for production taxes which would have been material to the first quarter of 2015 and could be material to projected 2015 annual results if recorded as an out of period adjustment in such period. Therefore we have revised our Balance Sheet and Consolidated Statement of Operations for the year and quarter ended December 31, 2014, as noted in the table below. This revision had no impact on our net cash provided by operations in our Consolidated Statement of Cash Flows for the twelve months ended December 31, 2014. We have determined that this error is not material to the consolidated financial statements of any prior period presented.

1. Organization and Description of Business (Continued)

In addition, we identified an error in our previously issued Form 10-K for the year ended December 31, 2014 related to the exchange of Class B shares for Class A shares. Therefore we revised our Consolidated Balance Sheet and Statement of Changes in Stockholders' Equity for the year ended December 31, 2014 as noted in the table below. This revision had no impact on Class A or Class B shares outstanding at December 31, 2014. We have determined that this error is not material to the consolidated financial statements of any prior period presented.

Consolidated Balance Sheet:

(in thousands of dollars)	December 31, 2014 As Reported	Production tax	Exchange of Class B shares	December 31, 2014 As Revised
Accounts Receivable, Oil and gas sales	$ 49,861	$1,621	—	$ 51,482
Deferred tax liabilities	$ 27,330(1)	$ 144	—	$ 27,474
Additional paid in capital	$177,133	—	$ 1,630	$178,763
Retained earnings	$ 38,682	$ 268	—	$ 38,950
Non-controlling interest	$636,366	$1,209	$(1,630)	$635,945

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

Consolidated Statements of Operations—for the twelve months ended:

(in thousands except per share data)	December 31, 2014 As Reported	Production tax	December 31, 2014 As Revised
Production and ad valorem taxes	$ 24,177(1)	$(1,621)	$ 22,556
Income tax provision (benefit)	$ 26,074	$ 144	$ 26,218
Net income (loss)	$224,143	$ 1,477	$225,620
Net income (loss) attributable to non-controlling interests	$183,275	$ 1,209	$184,484
Net income (loss) attributable to controlling interests	$ 40,868	$ 268	$ 41,136
Earnings (Loss) per share:			
Basic	$ 3.26	$ 0.02	$ 3.28
Diluted	$ 3.26	$ 0.02	$ 3.28

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

2. Significant Accounting Policies

Basis of Presentation

The accompanying financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). All significant intercompany transactions and balances have been eliminated in consolidation. The financial statements reported for December 31, 2015 and 2014 and the results of the operations and the cash flows for each of the three years in the period ended December 31, 2014 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, 2015 and at December 31, 2014 of derivative positions not settled as of the balance sheet date and severance tax refunds due from state agencies. 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, 2015 and 2014, the Company did not have significant allowances for doubtful accounts.

2. Significant Accounting Policies (Continued)

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, 2015, 68% of Accounts receivable—Oil and gas sales are due from four purchasers and 80% of Accounts receivable—Joint interest owners are due from five working interest owners. As of December 31, 2014, 70% of Accounts receivable—Oil and gas sales were due from five purchasers and 67% of Accounts receivable—Joint interest owners were due from five working interest owners. As of December 31, 2013, 79% of Accounts receivable—Oil and gas sales were due from eight purchasers and 77% of Accounts receivable—Joint interest owners were 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.

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, 2015, the largest purchasers were Valero Energy Corp. ("Valero"), ETC Field Services LLC, Plains Marketing LP ("Plains Marketing"), NGL Energy Partners LP, and Unimark LLC, which accounted for approximately 18%, 17%, 16%, 15% and 7% of consolidated oil and gas sales, respectively. During the year ended December 31, 2014, the largest purchasers were Valero Energy Corp. ("Valero"), NGL Energy Partners LP, PVR Midstream LLC ("PVR Midstream"), Plains Marketing LP ("Plains Marketing"), and Monarch Natural Gas LLC which accounted for approximately 22%, 12%, 12%, 10% and 10% of consolidated oil and gas sales, respectively. During the year ended December 31, 2013, the largest purchasers were PVR Midstream, Unimark LLC, Mercuria Energy Group Ltd. ("Mercuria"), Valero, and Plains Marketing, which accounted for approximately 15%, 13%, 13%, 13% and 6% 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.

2. Significant Accounting Policies (Continued)

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. Fair value is calculated by discounting the future cash flows at an appropriate risk- adjusted discount rate. Due to the significant assumptions associated with the inputs and calculations described, the fair value of oil and gas properties used in estimating impairment represents a nonrecurring Level 3 measurement.

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 results of any drilling and seismic activity during the period and known information regarding exploration and development activity by other companies on adjacent blocks.

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

2. Significant Accounting Policies (Continued)

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.

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, 2015, 2014 and 2013, the Company elected not to designate any of its commodity price risk management activities as cash flow or fair value hedges. The changes in the fair values of outstanding financial instruments are recognized as gains or losses in the period of change.

Although the Company does not designate its commodity derivative instruments as cash-flow hedges, management uses those instruments to reduce the Company's exposure to fluctuations in commodity prices related to its natural gas and oil production. Net gains and losses, at fair value, are included on the Consolidated Balance Sheet as current or noncurrent assets or liabilities based on the anticipated timing of cash settlements under the related contracts. Changes in the fair value of commodity derivative contracts are recorded in earnings as they occur and are included in other income (expense) on the Consolidated Statement of Operations. See Note 7, "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.

Revenue Recognition

Revenues from the sale of crude oil, natural gas, and natural gas liquids are valued at the estimated sales price and recognized when the product is delivered at a fixed or determinable price, title has transferred, collectability is reasonably assured and evidenced by a contract. The Company

2. Significant Accounting Policies (Continued)

follows the "sales method" of accounting for its oil and natural gas revenue, so it recognizes revenue on all crude oil, natural gas, and natural gas liquids sold to purchasers. A receivable or liability is recognized only to the extent that the Company has an imbalance on a specific property greater than the expected remaining proved reserves. Any such imbalances were not significant as of December 31, 2015.

Income Taxes

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

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

The Company records a valuation allowance if it is deemed more likely than not that all or a portion of its deferred income tax assets will not be realized. In addition, income tax rules and regulations are subject to interpretation and the application of those rules and regulations require judgment by the Company and may be challenged by the taxation authorities. The Company follows 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

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") No. 2014-09, "Revenue from Contracts with Customers," which creates a new topic in the ASC, topic 606, "Revenue from Contracts with Customers." This ASU sets forth a five-step model for determining when and how revenue is recognized. Under the model, an entity will be required to recognize revenue to depict the transfer of goods or services to a customer at an amount reflecting the consideration it expects to receive in exchange for those goods or services. Additional disclosures will be required to describe the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts. In August 2015, the FASB issued ASU 2015-14 which deferred the effective

2. Significant Accounting Policies (Continued)

date of ASU 2014-09 by one year. The amendments are now effective for interim and annual reporting periods beginning after December 15, 2017 and may be applied on either a full or modified retrospective basis. Early adoption is permitted. We are currently evaluating the effect that the adoption of Update 2014-09 and Update 2015-14 will have on our financial statements.

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

In April 2015, the FASB issued ASU No. 2015-03, Interest—Imputation of Interest (Subtopic 835-30): Simplifying the Presentation of Debt Issuance Costs. Entities that have historically presented debt issuance costs as an asset, related to a recognized debt liability, will be required to present those costs as a direct deduction from the carrying amount of that debt liability. The ASU does not change the recognition, measurement, or subsequent measurement guidance for debt issuance costs. Adoption of this ASU will be applied retrospectively. In August 2015, the FASB issued ASU No. 2015-15, Interest—Imputation of Interest (Subtopic 835-30) (“Update 2015-15”), which addresses the presentation or subsequent measurement of debt issuance costs related to line-of-credit arrangements, given the absence of authoritative guidance within Update 2015-03 for debt issuance costs related to line-of-credit arrangements. The amendments are effective for interim and annual reporting periods beginning after December 15, 2015. The Company does not expect the adoption of this guidance to have a material impact on its financial position, cash flows or results of operations.

In November 2015, the FASB issued ASU No. 2015-17, Balance Sheet Classification of Deferred Taxes. This ASU requires companies to classify all deferred tax assets and liabilities as noncurrent on the balance sheet instead of separating deferred taxes into current and noncurrent amounts. The guidance is effective for financial statements issued for annual periods beginning after 15 December 2016, and interim periods within those annual periods. Early adoption is permitted. The guidance may be adopted on either a prospective or retrospective basis. The Company has chosen to early adopt ASU No. 2015-17 for the period ended December 31, 2015. Changes to the balance sheet have been applied on a retrospective basis. Adoption did not have a material impact on the financial position, cash flows or results of operations.

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

Jones Energy, Inc.
Notes to the Consolidated Financial Statements (Continued)

3. Properties, Plant and Equipment

Oil and Gas Properties

The Company accounts for its oil and natural gas exploration and production activities under the successful efforts method of accounting. Oil and gas properties consisted of the following at December 31, 2015 and 2014:

(in thousands of dollars)	2015	2014
Mineral interests in properties		
Unproved	$ 75,308	$ 94,526
Proved	1,031,669	1,001,194
Wells and equipment and related facilities	1,289,323	1,094,202
	2,396,300	2,189,922
Less: Accumulated depletion and impairment	(760,534)	(551,062)
Net oil and gas properties	$1,635,766	$1,638,860

As of December 31, 2015 and 2014, we had no material capitalized costs associated with exploratory wells.

No interest costs were capitalized in 2015. The Company capitalized less than $0.1 million in interest costs during 2014. Costs incurred to maintain wells and related equipment are charged to expense as incurred.

Depletion of oil and gas properties amounted to $204.2 million, $180.6 million, and $113.3 million for the years ended December 31, 2015, 2014, and 2013, respectively.

No impairments of proved or unproved properties were recorded in 2015, 2014, or 2013. Certain prior period amounts have been reclassified to conform to the current presentation, include the reclassification of Impairment of oil and gas properties to Exploration in the Consolidated Statement of Operations for the twelve months ended December 31, 2013 relating to lease abandonment charges of $14.4 million for certain leases that the Company did not plan to develop.

Other Property, Plant and Equipment

Other property, plant and equipment consisted of the following at December 31, 2015 and 2014:

(in thousands of dollars)	2015	2014
Leasehold improvements	$ 1,260	$ 1,218
Furniture, fixtures, computers and software	4,090	3,727
Vehicles	1,537	988
Aircraft	910	910
Other	247	219
	8,044	7,062
Less: Accumulated depreciation and amortization	(4,171)	(3,014)
Net other property, plant and equipment	$ 3,873	$ 4,048

3. Properties, Plant and Equipment (Continued)

Depreciation and amortization of other property, plant and equipment amounted to $1.3 million, $1.1 million, and $0.8 million during the years ended December 31, 2015, 2014 and 2013, respectively.

4. Acquisition of Properties

No business combinations occurred during the twelve months ended December 31, 2015 and 2014.

On December 18, 2013, JEH closed on the purchase of certain oil and natural gas properties located in Texas and western Oklahoma from Sabine Mid-Continent, LLC, for a purchase price of $193.5 million (referred to herein as the "Sabine acquisition" or "Sabine"), subject to customary closing adjustments. The acquired assets included both producing properties and undeveloped acreage. The purchase was financed with borrowings under the Revolver. In the second quarter of 2014, the Company made a final determination with the sellers as to the purchase price resulting in a final purchase price of $179.2 million. The amount of the total purchase price allocated to undeveloped oil and gas properties was reduced by these adjustments. The adjustments were retroactively applied to our December 31, 2013 Consolidated Balance Sheet as a reduction to oil and gas properties and an increase in receivables. The adjusted purchase price was allocated as follows:

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

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

(in thousands of dollars)	Post Acquisition(1) (unaudited)	Year Ended December 31, 2013 Pro Forma (unaudited)
Total operating revenue	$1,365	$308,773
Total operating expenses	291	229,648
Operating income	1,074	79,125
Net income	1,074	45,778

(1) Represents revenues and expenses for the post acquisition period of December 18, 2013 to December 31, 2013 included in the Consolidated Statement of Operations.

The acquisition qualified as a business combination. The valuation to determine the fair values were principally based on the discounted cash flows of the producing and undeveloped properties, including projected drilling and equipment costs, recoverable reserves, production streams, future prices and operating costs, and risk-adjusted discount rates reflective of the market at the time of acquisition.

5. Long-Term Debt

Long-term debt consisted of the following at December 31, 2015 and 2014:

(in thousands of dollars)	December 31, 2015	December 31, 2014
Revolver	$110,000	$360,000
2022 Notes	500,000	500,000
2023 Notes	250,000	—
Total principal amount	860,000	860,000
Less: unamortized discount	(12,088)	—
Total carrying amount	$847,912	$860,000

Senior Unsecured Notes

On April 1, 2014, JEH and Jones Energy Finance Corp., JEH's wholly-owned subsidiary formed for the sole purpose of co-issuing certain of JEH's debt (together the "Issuers"), sold $500.0 million in aggregate principal amount of the Issuers' 6.75% senior notes due 2022 (the "2022 Notes"). The Company used the net proceeds from the issuance of the 2022 Notes to repay all outstanding borrowings under the Term Loan ($160.0 million), a portion of the outstanding borrowings under the Revolver ($308.0 million) and for working capital and general corporate purposes. The Company subsequently terminated the Term Loan in accordance with its terms. The 2022 Notes bear interest at a rate of 6.75% per year, payable semi-annually on April 1 and October 1 of each year beginning October 1, 2014.

On February 5, 2015, the Company filed a registration statement on Form S-4 to register exchange notes that are substantially similar to the 2022 Notes, except that the transfer restrictions, registration rights and additional interest provisions related to the outstanding 2022 Notes do not apply to the new 2022 Notes. On February 20, 2015, the registration statement was declared effective and the Company commenced an offer to exchange any and all of its $500 million outstanding principal amount of 2022 Notes for an equal amount of new 2022 Notes. The exchange offer expired on March 23, 2015. Tenders of $500 million aggregate principal amount, or 100%, of the 2022 Notes were received.

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

On November 18, 2015, the Company filed a registration statement on Form S-4 to register exchange notes that are substantially similar to the 2023 Notes, except that the transfer restrictions, registration rights and additional interest provisions related to the outstanding 2023 Notes do not apply to the new 2023 Notes. See Note 15, "Subsequent Events," in the Notes to Consolidated Financial Statements for further discussion.

5. Long-Term Debt (Continued)

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 similar 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. However, many of these covenants will be suspended if the Notes are rated investment grade.

Other Long-Term Debt

The Company entered into two credit agreements dated December 31, 2009, with Wells Fargo Bank N.A, the Senior Secured Revolving Credit Facility (the "Revolver") and the Second Lien Term Loan (the "Term Loan"), each of which have been or were amended periodically. On April 1, 2014, the Term Loan was repaid in full and terminated in connection with the issuance of the 2022 Notes. On November 6, 2014, the Company amended the Revolver to, among other things, increase the borrowing base under the Revolver from $550.0 million to $625.0 million until the next redetermination thereof, and extend the maturity date of the Revolver to November 6, 2019. The Company's oil and gas properties are pledged as collateral to secure its obligations under the Revolver. The borrowing base on the Revolver was subsequently adjusted to $562.5 million in accordance with its terms as a result of the issuance of the 2023 Notes in February 2015 and was reaffirmed at this level effective April 1, 2015. Effective October 8, 2015, the borrowing base was reduced to $510 million during the semi-annual borrowing base re-determination.

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

Interest on the Revolver is calculated, at the Company's option, at either (a) the London Interbank Offered ("LIBO") rate for the applicable interest period plus a margin of 1.50% to 2.50% based on the level of borrowing base utilization at such time or (b) the greatest of the federal funds rate plus 0.50%, the one-month adjusted LIBO rate plus 1.00%, or the prime rate announced by Wells Fargo Bank, N.A. in effect on such day, in each case plus a margin of 0.50% to 1.50% based on the level of borrowing base utilization at such time. For the year ended December 31, 2015, the average

5. Long-Term Debt (Continued)

interest rate under the Revolver was 2.39% on an average outstanding balance of $144.9 million. For the year ended December 31, 2014, the average interest rate under the Revolver was 2.51% on an average outstanding balance of $333.8 million.

Total interest and commitment fees under the Revolver were $5.1 million, $9.5 million, and $12.3 million for the years ended December 31, 2015, 2014 and 2013, respectively. Total interest and commitment fees under the Term Loan were $3.6 million and $14.7 million for the years ended December 31, 2014 and 2013, respectively.

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

- a total leverage ratio, consisting of consolidated debt to EBITDAX, of not greater than 4.00 to 1.00 as of the last day of any fiscal quarter; and
- a current ratio, consisting of consolidated current assets, including the unused amounts of the total commitments, to consolidated current liabilities, of not less than 1.0 to 1.0 as of the last day of any fiscal quarter.

As of December 31, 2015, our total leverage ratio is approximately 3.2 and our current ratio is approximately 6.9, as calculated based on the requirements in our covenants. We believe that we are in compliance with all terms of our Revolver and expect to maintain compliance during 2016. However, factors including those outside of our control, such as commodity price declines, may prevent us from maintaining compliance with these covenants, at future measurement dates in 2016 and beyond. In the event it were to became necessary, we believe we have the ability to take actions that would prevent us from failing to comply with our covenants, such as hedge restructuring. While it is our expectation that we will continue to be in compliance with our covenants, no assurance can be given that this will be the case. If an event of default exists under the Revolver, the lenders will be able to accelerate the obligations outstanding under the Revolver and exercise other rights and remedies. Our Revolver contains customary events of default, including the occurrence of a change of control, as defined in the Revolver.

6. Derivative Instruments and Hedging Activities

The Company had various commodity derivatives in place that could affect its future operations as of December 31, 2015 and 2014, as follows:

Hedging Positions

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

		December 31, 2014			
		Low	High	Weighted Average	Final Expiration
Oil swaps	Exercise price	$ 75.05	$ 100.95	$ 84.20	
	Barrels per month	45,000	184,054	113,852	December 2018
Natural gas swaps	Exercise price	$ 3.37	$ 6.45	$ 4.40	
	mmbtu per month	710,000	1,772,584	1,175,275	December 2018
Basis swaps	Contract differential	$ (0.39)	$ (0.11)	$ (0.21)	
	mmbtu per month	320,000	980,000	716,667	March 2016
Natural gas liquids swaps	Exercise price	$ 8.09	$ 95.24	$ 42.46	
	Barrels per month	2,000	143,000	50,444	December 2017

The Company recognized a net gain on derivative instruments of $158.8 million and $189.6 million for the years ended December 31, 2015 and 2014, respectively, and a net loss of $2.6 million for the year ended December 31, 2013.

Offsetting Assets and Liabilities

As of December 31, 2015, the counterparties to our commodity derivative contracts consisted of six financial institutions. All of our counterparties or their affiliates are also lenders under the Revolver. We are not generally required to post additional collateral under our derivative agreements.

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

We adopted the guidance requiring disclosure of both gross and net information about financial instruments eligible for netting in the balance sheet under our derivative agreements. The following

6. Derivative Instruments and Hedging Activities (Continued)

table presents information about our commodity derivative contracts that are netted on our Consolidated Balance Sheet as of December 31, 2015 and December 31, 2014:

(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, 2015					
Commodity derivative contracts					
Assets	$218,036	$(527)	$217,509	$—	$217,509
Liabilities	(538)	527	(11)	—	(11)
December 31, 2014					
Commodity derivative contracts					
Assets	$208,646	$ (72)	$208,574	$—	$208,574
Liabilities	(100)	72	(28)	—	(28)

7. Fair Value Measurement

Fair Value of Financial Instruments

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

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

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

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

7. Fair Value Measurement (Continued)

Valuation Hierarchy

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

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

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

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

The financial instruments carried at fair value as of December 31, 2015 and 2014, by consolidated balance sheet caption and by valuation hierarchy, as described above are as follows:

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

	December 31, 2014			
	Fair Value Measurements Using			
(in thousands of dollars)	**(Level 1)**	**(Level 2)**	**(Level 3)**	**Total**
Commodity Price Hedges				
Current assets	$—	$120,604	$ 915	$121,519
Long-term assets	—	85,162	1,893	87,055
Current liabilities	—	—	—	—
Long-term liabilities	—	—	28	28

7. Fair Value Measurement (Continued)

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, 2015.

	Quantitative Information About Level 3 Fair Value Measurements			
Commodity Price Hedges	**Fair Value (000's)**	**Valuation Technique**	**Unobservable Input**	**Range**
Natural gas liquid swaps	$1,428	Use a discounted cash flow approach using inputs including forward price statements from counterparties	Natural gas liquid futures	$8.90 - $47.25 per barrel

Significant increases/decreases in natural gas liquid prices in isolation would result in a significantly lower/higher fair value measurement. The following table presents the changes in the Level 3 financial instruments for the years ended December 31, 2015 and 2014. Changes in fair value of Level 3 instruments represent changes in gains and losses for the periods that are reported in other income (expense). New contracts entered into during the year are generally entered into at no cost with changes in fair value from the date of agreement representing the entire fair value of the instrument. Transfers between levels are evaluated at the end of the reporting period.

(in thousands of dollars)	
Balance at December 31, 2013, net	$(1,235)
Purchases	668
Settlements	476
Transfers into Level 3	(265)
Transfers to Level 2	332
Changes in fair value	2,804
Balance at December 31, 2014, net	2,780
Purchases	648
Settlements	(960)
Transfers into Level 3	—
Transfers to Level 2	(1,367)
Changes in fair value	327
Balance at December 31, 2015, net	$ 1,428

Transfers from Level 3 to Level 2 represent the Company's natural gas basis swaps for which observable forward curve pricing information has become readily available. Purchases represent natural gas liquid swaps that the Company entered into that do not have observable forward curve pricing information.

7. Fair Value Measurement (Continued)

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

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

(in thousands of dollars)	December 31, 2015 Principal Amount	December 31, 2015 Fair Value	December 31, 2014 Principal Amount	December 31, 2014 Fair Value
Debt:				
Revolver	$110,000	$110,000	$360,000	$360,000
2022 Notes	500,000	260,000	500,000	384,375
2023 Notes	250,000	153,283	—	—

The Revolver (as defined in Note 5) 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 5) is based on pricing that is readily available in the public market. Accordingly, the 2022 Notes are classified as Level 1 in the valuation hierarchy as the pricing is based on quoted market prices for the debt securities and is actively traded.

The fair value of the 2023 Notes (as defined in Note 5) 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.

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

The Company reviews its proved oil and gas properties for impairment purposes by comparing the expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. Significant assumptions associated with the calculation of future cash flows used in the impairment analysis include the Company's estimate of future commodity prices, production costs, development expenditures, production, risk-adjusted discount rates, and other relevant data. As such, the fair value of oil and gas properties used in estimating impairment represents a nonrecurring Level 3 measurement.

8. Asset Retirement Obligations

A summary of the Company's ARO for the years ended December 31, 2015 and 2014 is as follows:

(in thousands of dollars)	2015	2014
ARO liability at beginning of year	$13,610	$10,963
Liabilities incurred(1)	6,349	1,995
Accretion of ARO liability	1,087	770
Liabilities settled due to sale of related properties	(19)	(109)
Liabilities settled due to plugging and abandonment	(69)	(55)
Change in estimate	22	46
ARO liability at end of year	20,980	13,610
Less: Current portion of ARO at end of year	(679)	(3,074)
Total long-term ARO at end of year	$20,301	$10,536

(1) Includes $4.7 million to correct immaterial errors originating in 2013 and 2014. In addition to the balance sheet impact noted, Accretion of ARO liability of $0.2 million and Depletion, depreciation, and amortization of $0.6 million were recognized in our statement of operations during the fourth quarter of 2015 as a correcting adjustment. We have determined that this adjustment is not material to the consolidated financial statements of any period presented.

9. Stock-based Compensation

Management Unit Awards

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

The following table summarizes information related to the vesting of management units as of December 31, 2015:

	JEH Units	Weighted Average Grant Date Fair Value per Share
Unvested at December 31, 2014	274,385	$15.00
Granted	1,909	$15.00
Forfeited	(1,909)	$15.00
Vested	(85,030)	$15.00
Unvested at December 31, 2015	189,355	$15.00

9. Stock-based Compensation (Continued)

Stock compensation expense associated with the management units for the years ended December 31, 2015, 2014 and 2013 was $1.3 million, $1.6 million, and $10.7 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 management units was $15.00 per share for the year ended December 31, 2015. Unrecognized expense as of December 31, 2015 for all outstanding management units was $2.8 million and will be recognized over a weighted-average remaining period of 1.2 years.

2013 Omnibus Incentive Plan

Under the Jones Energy, Inc. 2013 Omnibus Incentive Plan (the "LTIP"), established in conjunction with the Company's IPO, the Company reserved 3,850,000 shares of Class A common stock for non-employee director, consultant and employee stock-based compensation awards.

The Company granted (i) performance unit and restricted stock unit awards to certain officers and employees and (ii) restricted shares of Class A common stock to the Company's non-employee directors under the LTIP during 2014 and 2015.

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 was based on the value of the Company's Class A common stock on the date of grant and is expensed on a straight-line basis over the applicable 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, 2015:

	Restricted Stock Unit Awards	Weighted Average Grant Date Fair Value per Share
Unvested at December 31, 2014	324,897	$17.33
Granted	572,939	$ 9.58
Forfeited	(14,995)	$12.84
Vested	(125,596)	$16.75
Unvested at December 31, 2015	757,245	$11.65

Stock compensation expense associated with the employee restricted stock unit awards for the years ended December 31, 2015 and 2014 was $3.1 million and $1.1 million, respectively, and is included in general and administrative expenses on the Company's Consolidated Statement of Operations. There was no stock compensation expense associated with the employee restricted stock unit awards for the year ended December 31, 2013. The weighted average grant date fair value of restricted stock units was $9.58 per share, and $17.31 per share for the years ended December 31, 2015 and 2014, with no awards made during the year ended December 31, 2013. Unrecognized expense as of December 31, 2015 for all outstanding restricted stock unit awards was $5.9 million and will be recognized over a weighted-average remaining period of 1.1 years.

9. Stock-based Compensation (Continued)

Performance Unit Awards

The Company has outstanding performance unit awards granted to certain officers of the Company under the LTIP. Upon the completion of the applicable three-year performance period, each officer may vest in a number of performance units. The percent of awarded performance units in which each officer 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 unit is exchangeable for one share of the Company's Class A common stock. The grant date fair value of the performance units was determined using a Monte Carlo simulation model, which results in an estimated percentage of performance units earned. The fair value of the performance 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 units awarded to the officers as of December 31, 2015:

	Performance Unit Awards	Weighted Average Grant Date Fair Value per Share
Unvested at December 31, 2014	192,998	$21.65
Granted	361,422	$10.27
Forfeited	—	—
Vested	(15,232)	$14.59
Unvested at December 31, 2015	539,188	$14.22

Stock compensation expense associated with the performance unit awards for the years ended December 31, 2015 and 2014 was $2.6 million and $0.9 million, respectively, and is included in general and administrative expenses on the Company's Consolidated Statement of Operations. There was no stock compensation expense associated with the performance unit awards for the year ended December 31, 2013. The weighted average grant date fair value of performance unit awards was $10.27 per share, and $21.65 per share for the years ended December 31, 2015 and 2014, with no awards made during the year ended December 31, 2013. Unrecognized expense as of December 31, 2015 for all outstanding performance unit awards was $4.0 million and will be recognized over a weighted-average remaining period of 1.5 years.

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

9. Stock-based Compensation (Continued)

The following assumptions were used for the Monte Carlo simulation model to determine the grant date fair value and associated compensation expense during the periods presented:

	2015 Performance Unit Awards	2014 Performance Unit Awards
Stock Price(1)	$10.11	$17.07
Beginning Average Stock Price(2)	$11.56	$14.78
Expected Volatility(3)	55.13%	46.95%
Risk-Free Rate of Return(4)	0.79%	0.61%

(1) Based on the closing price of Jones Energy, Inc. Class A common stock on April 29, 2015 and May 20, 2014.

(2) Based on the 10 trading days immediately prior to the beginning of the performance period.

(3) For the 2015 award this is based on the average historical volatilities over the most recent 2.67-year period for the Company and each peer company using daily stock prices through April 29, 2015. The measurement period reflects the 2.67 years remaining in the performance period as of the grant date.

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

(4) Based on the yield curve of U.S. Treasury rates as of April 29, 2015 and May 20, 2014.

Based on these assumptions, the Monte Carlo simulation model resulted in an expected percentage of performance units earned of 101.61% and 126.80% for the 2015 and 2014 awards, respectively.

Restricted Stock Awards

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

9. Stock-based Compensation (Continued)

The following table summarizes information related to the total value of the awards to the Board of Directors as of December 31, 2015:

	Restricted Stock Awards	Weighted Average Grant Date Fair Value per Share
Unvested at December 31, 2014	27,430	$18.77
Granted	67,380	$ 7.30
Forfeited	—	—
Vested	(27,430)	$18.77
Unvested at December 31, 2015	67,380	$ 7.30

Stock compensation expense associated with the Board of Directors awards for the years ended December 31, 2015, 2014 and 2013 was $0.6 million, $0.4 million, and $0.1 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 restricted stock awards was $7.30 per share, $18.77 per share, and $15.05 per share for the years ended December 31, 2015, 2014 and 2013. Unrecognized expense as of December 31, 2015 for all outstanding restricted stock awards was $0.2 million and will be recognized over the remaining vesting period of 0.4 years.

For the years ended December 31, 2015, 2014, and 2013, the Company had an associated tax benefit of $1.1 million, $0.4 million, and $0.1 million, respectively, related to all stock-based compensation, calculated at the federal statutory rate after adjusting for the non-controlling interest.

10. Benefit Plans

The Company established 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, during 2013, the Company established 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. For the year ended December 31, 2015, our total expense relating to these plans was $0.5 million. Our total expense relating to these plans for each of the years ended December 31, 2014 and 2013 was $0.3 million.

11. Income Taxes

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

11. Income Taxes (Continued)

The following table summarizes the tax provision for the years ended December 31, 2015, 2014 and 2013:

(in thousands of dollars)	Year Ended December 31, 2015	2014	2013
Current tax expense:			
Federal	$ —	$ 53	$ 85
State	113	—	—
Total current expense	113	53	85
Deferred tax expense (benefit):			
Federal	(1,137)	22,140	(1,260)
State	(1,757)	4,025	1,104
Total deferred expense (benefit)	(2,894)	26,165	(156)
Total tax expense (benefit)	(2,781)	$26,218	$ (71)
Tax expense (benefit) attributable to controlling interests	(1,160)	22,819	$(1,223)
Tax expense attributable to non-controlling interests	(1,621)	3,399	1,152
Total income tax expense (benefit)	(2,781)	$26,218	$ (71)

For the pre-IPO period of the year ended December 31, 2013, the reported taxes in the table above relate solely to the Texas franchise tax liability of JEH.

11. Income Taxes (Continued)

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 35%:

(in thousands of dollars)	2015	2014	2013
Provision calculated at federal statutory income tax rate:			
Net income before taxes	$(11,858)	$251,838	$22,334
Statutory rate	35%	35%	35%
Income tax expense (benefit) computed at statutory rate	$ (4,150)	$ 88,144	$ 7,817
Less: Non-controlling interests	2,911	(65,759)	(9,009)
Income tax expense (benefit) attributable to controlling interests	(1,239)	22,385	(1,192)
State and local income taxes, net of federal benefit	(1,011)	626	(49)
Reduction of TRA liability	(694)	—	—
Equity compensation, shortfall	338	—	—
Change in enacted rate	(650)	—	—
Change in valuation allowance	2,333	—	—
Other	(237)	(192)	18
Tax expense (benefit) attributable to controlling interests	(1,160)	22,819	(1,223)
Tax expense attributable to non-controlling interests	(1,621)	3,399	1,152
Total income tax expense (benefit)(1)	$ (2,781)	$ 26,218	$ (71)

(1) Deferred tax expense of the year ended December 31, 2015 includes the correction of an immaterial error from the year ended December 31, 2014, whereby deferred tax expense was overstated in 2014 and understated in 2015 by $0.9 million. We have determined that this adjustment is not material to the consolidated financial statements of any period presented.

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 2015, Texas enacted legislation that reduced the tax rate from 1.0% to 0.75%. We recorded a tax benefit of $1.7 million as a result of revaluing our deferred tax assets at the newly enacted rate, of which $1.0 million was attributable to the non-controlling interest.

11. Income Taxes (Continued)

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

(in thousands of dollars)	As of December 31, 2015	2014
Deferred tax assets		
Net operating loss	$ 9,414	$ 8,223
Section 754 election tax basis adjustment	47,100	945
Alternative minimum tax credits	—	53
Other deferred tax asset	505	232
Total deferred tax assets	57,019	9,453
Deferred tax liabilities		
Investment in consolidated subsidiary JEH	73,559	29,307
Noncurrent state deferred tax liability	4,099	7,449
Total deferred tax liabilities	77,658	36,756
Net deferred tax assets (liabilities)	(20,639)	(27,303)
Valuation allowance	(2,333)	—
Net deferred tax assets (liabilities)	$(22,972)	$(27,303)

The Company has a federal net operating loss carry-forward totaling $24.8 million and state net operating loss carry-forward of $19.5 million, both of which expire between 2033 and 2035. 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, 2015, we have a valuation allowance of $2.3 million as a result of management's assessment of the realizability of deferred tax assets in Oklahoma. Management believes that there will be sufficient future taxable income based on the reversal of temporary differences to enable utilization of substantially all other tax carryforwards.

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 2011 through 2015. The tax years 2012 through 2015 remain open to examination by the major taxing jurisdictions to which the Company is subject. The Internal Revenue Service is currently examining the 2013 federal partnership income tax return for JEH.

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, 2015, 2014 and 2013 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.

11. Income Taxes (Continued)

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. At the time of an exchange, the company records a liability to reflect the future payments under the TRA.

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. In the event that the Company records a valuation allowance against its deferred tax assets associated with an exchange, the TRA liability will also be reduced as the payment of the TRA liability is dependent on the realizability of the deferred tax assets. As of December 31, 2015, the amount of the TRA liability was reduced by $2.0 million 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, 2015 and 2014 the Company had recorded a TRA liability of $38.1 million and $0.8 million, respectively, for the estimated payments that will be made to the pre-IPO members who have exchanged shares along with corresponding deferred tax assets, net of valuation allowance, of $44.8 million and $0.9 million, respectively, as a result of the increase in tax basis generated arising from such exchanges. The increase in the TRA liability was primarily driven by the exchange of 5 million JEH Units and Class B shares of common stock by Metalmark Captial in May of 2015.

As of December 31, 2015, the Company had not made any payments under the TRA to pre-IPO members who have exchanged JEH units and Class B common stock for Class A common stock. The Company does not anticipate making a material payment under the TRA in 2016.

12. Earnings per Share

Basic earnings per share ("EPS") is computed by dividing net income (loss) attributable to controlling interests by the weighted-average number of shares of Class A common stock outstanding during the period. Shares of Class B common stock are not included in the calculation of earnings per share because they are not participating securities and have no economic interest in the Company. Diluted earnings per share takes into account the potential dilutive effect of shares that could be issued by the Company in conjunction with stock awards that have been granted to directors and employees. Awards of nonvested shares are considered outstanding as of the respective grant dates for purposes of computing diluted EPS even though the award is contingent upon vesting. For the twelve months ended December 31, 2015, 757,245 restricted stock shares, 67,380 restricted stock units and 539,188 performance units were excluded from the calculation as they would have had an anti-dilutive effect. For the twelve months ended December 31, 2014, 27,430 restricted stock shares, 54,656 restricted stock units and 192,998 performance units were excluded from the calculation as they would have had an anti-dilutive effect. The following is a calculation of the basic and diluted weighted-average number of shares of Class A common stock outstanding and EPS. 2014 is calculated using the twelve months

12. Earnings per Share (Continued)

ended December 31, 2014. 2013 is calculated for the period from July 29, 2013, the closing date of the IPO, to December 31, 2013.

Basic Earnings per Share

(in thousands, except per share data)	2015	2014	2013
Income (numerator):			
Net income (loss) attributable to controlling interests	$(2,381)	$41,136	$(2,186)
Weighted-average shares (denominator):			
Weighted-average number of shares of Class A common stock—basic	26,816	12,526	12,500
Weighted-average number of shares of Class A common stock—diluted	26,816	12,535	12,500
Earnings (loss) per share:			
Basic	$ (0.09)	$ 3.28	$ (0.17)
Diluted	$ (0.09)	$ 3.28	$ (0.17)

13. Related Parties

Related Party Transactions

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. Under the Monarch agreement, the Company is paid a specified percentage of the value of the NGLs extracted and sold by Monarch, based on a set liquids recovery percentage, and the amount received from the sale of the residue gas, after deducting a fixed volume for fuel, lost and unaccounted for gas. The Company produced approximately 1.4 MMBoe of natural gas and NGLs for the year ended December 31, 2014 and 0.8 MMBoe of natural gas and NGLs for the year ended December 31, 2013, from the properties that became subject to the Monarch agreement. During the years ended December 31, 2014 and 2013, the Company recognized $37.0 million and $10.4 million, respectively, of revenue associated to the aforementioned natural gas and NGL production. Effective May 1, 2015, the rights to gather natural gas under the sale and purchase agreement transferred from Monarch to Enable Midstream Partners LP, (“Enable”), an unaffiliated third-party. Prior to closing of the transfer of these rights, the Company produced approximately 1.0 MMBoe of natural gas and NGLs for the year ended December 31, 2015 from the properties that became subject to the Monarch agreement for which the Company recognized $10.6 million of revenue. The revenue, for all years mentioned, is recorded in Oil and gas sales on the Company’s Consolidated Statement of Operations. The initial term of the agreement, which remains unchanged by the transfer to Enable, runs for 10 years from the effective date of September 1, 2013.

At the time the Company entered into the 2013 Monarch agreement, Metalmark Capital owned approximately 81% of the outstanding equity interests of Monarch. In addition, Metalmark Capital

13. Related Parties (Continued)

beneficially owns in excess of five percent of the Company’s outstanding equity interests and two of our directors, Howard I. Hoffen and Gregory D. Myers, are managing directors of Metalmark Capital.

In the year ended December 31, 2013, the Company paid an annual administration fee to Metalmark of $0.7 million. This amount was recorded in general and administration expense on the Company’s Consolidated Statement of Operations. As a result of the IPO, this fee is no longer payable to Metalmark.

In connection with the Company’s entering into the 2013 Monarch agreement, Monarch issued to JEH equity interests in Monarch, having an estimated fair value of $15 million, in return for marketing services to be provided throughout the term of the agreement. The Company recorded this amount as deferred revenue which is being amortized on an estimated units-of-production basis commencing in September 2013, the first month of product sales to Monarch. During the years ended December 31, 2015, 2014 and 2013, the Company amortized $2.0 million, $1.2 million, and $0.5 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 the $15 million Monarch equity interests, JEH assigned $2.4 million of the equity interests to Jonny Jones, the Company’s chief executive officer and 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, including Mike McConnell, Robert Brooks and Eric Niccum. The remaining $10 million of Monarch equity interests was distributed to certain of the pre-IPO owners, which included Metalmark Capital, Wells Fargo, the Jones family entities, and certain of the Company’s officers and directors, including Jonny Jones, Mike McConnell and Eric Niccum. As of December 31, 2015, equity interests in Monarch of $1.3 million are included in Other assets on the Company’s Consolidated Balance Sheet. During the years ended December 31, 2015 and 2014, equity interests of $0.8 million and $0.5 million, respectively, were distributed to management under the incentive plan. The Company recognized expense of $0.5 million, $0.8 million, and $0.3 million during the years ended December 31, 2015, 2014, and 2013, respectively, in connection with the incentive plan.

In September 2014, the Company signed a 10-year oil gathering and transportation agreement with Monarch Oil Pipeline LLC, pursuant to which Monarch Oil Pipeline LLC built, at its expense, a new oil gathering system and connected the gathering system to dedicated Company leases in Texas. At the time the Company entered into the agreement, Metalmark Capital owned the majority of the outstanding equity interests of Monarch Oil Pipeline LLC and/or its parent. The system began service during the fourth quarter of 2015 and provides connectivity to both a regional refinery market as well as the Cushing market hub. The Company did not incur or capitalize any costs associated with the construction of the pipeline. The Company did, however, incur gathering fees of $0.4 million which were paid to Monarch Oil Pipeline LLC associated with the approximately 0.2 MMBoe of oil production transported under the agreement for the year ended December 31, 2015. These costs are recorded as an offset to Oil and gas sales in the Company’s Consolidated Statement of Operations. The aforementioned production was recognized as Oil and gas sales on the Company’s Consolidated Statement of Operations at the time it was sold to the purchasers, who are unaffiliated third-parties, after passing through the gathering and transportation system. The Company has reserved capacity of up to 12,000 barrels per day on the system with the potential to increase throughput at a future date. The audit committee of the Board reviewed and approved the terms of the agreement with Monarch Oil Pipeline LLC.

13. Related Parties (Continued)

In May 2015, the Company received a $0.7 million cash distribution associated with its equity interests in Monarch, which was accounted for following the cost method. The initial cash distribution from Monarch was treated as dividend income and is recorded in Other income (expense).

14. Commitments and Contingencies

Lease obligations

The Company leases approximately 43,000 square feet of office space in Austin, TX under an operating lease arrangement. Future minimum payments for all noncancellable operating leases extending beyond one year at December 31, 2015 are as follows:

(in thousands of dollars)	
Years Ending December 31,	
2016	$ 945
2017	1,038
2018	1,101
2019	1,122
2020	377
Thereafter	—
	$4,583

Rent expense under operating leases was $1.6 million, $0.9 million and $0.8 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Litigation

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

15. Subsequent Events

On November 18, 2015, the Company filed a registration statement on Form S-4 to register exchange notes that are substantially similar to the 9.25% senior notes due November 2023 (the "2023 Notes"), except that the transfer restrictions, registration rights and additional interest provisions related to the outstanding 2023 Notes do not apply to the new 2023 Notes. On January 12, 2016, the registration statement was declared effective and the Company commenced an offer to exchange any and all of its $250 million outstanding principal amount of 2023 Notes for an equal amount of new 2023 Notes. The exchange offer expired on February 11, 2016. Tenders of $250 million aggregate principal amount, or 100%, of the 2023 Notes were received.

In January and February 2016, through several open market and privately negotiated purchases, the Company purchased an aggregate principal amount of $170.5 million of its senior unsecured notes. As of February 29, 2016, the Company had purchased $70.5 million principal amount of its 2022 Notes for $27.1 million, and $100 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

15. Subsequent Events (Continued)

borrowings from its Revolver to fund the note purchases. As a result of these purchases, the Company had aggregate principal amount of senior unsecured notes outstanding of $579.5 million, outstanding borrowings under its revolving credit facility of $185 million, $325 million undrawn on its revolving credit facility, and $46 million in cash as of February 29, 2016.

16. Subsidiary Guarantors

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

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

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

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

As of December 31, 2015, the Company held approximately 49.4% of the economic interest in JEH, with the remaining 50.6% economic interest held by a group of investors that owned interests in JEH prior to the Company's IPO (the "Existing Owners"). The Existing Owners have no voting rights with respect to their economic interest in JEH.

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

In connection with a reorganization that occurred immediately prior to the IPO, each Existing Owner was issued a number of shares of Class B common stock that was equal to the number of JEH Units that such Existing Owner held. Holders of the Company's Class A common stock and Class B common stock generally vote together as a single class on all matters presented to the Company's

16. Subsidiary Guarantors (Continued)

stockholders for their vote or approval. Accordingly, the Existing Owners collectively have a number of votes in the Company equal to the aggregate number of JEH Units that they hold.

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

Condensed Consolidating Balance Sheet

December 31, 2015

(in thousands of dollars)	JEI(Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets						
Current assets						
Cash	$ 100	$ 12,448	$ 9,325	$ 20	$ —	$ 21,893
Restricted Cash	—	—	330	—	—	330
Accounts receivable, net						
Oil and gas sales	—	—	19,292	—	—	19,292
Joint interest owners	—	—	11,314	—	—	11,314
Other	—	14,444	726	—	—	15,170
Commodity derivative assets	—	124,207	—	—	—	124,207
Other current assets	—	444	1,854	—	—	2,298
Intercompany receivable	12,866	1,161,997	—	—	(1,174,863)	—
Total current assets	12,966	1,313,540	42,841	20	(1,174,863)	194,504
Oil and gas properties, net, at cost under the successful efforts method	—	—	1,635,766	—	—	1,635,766
Other property, plant and equipment, net	—	—	3,168	705	—	3,873
Commodity derivative assets	—	93,302	—	—	—	93,302
Other assets	—	17,714	253	—	—	17,967
Investment in subsidiaries	444,362	—	—	—	(444,362)	—
Total assets	$457,328	$1,424,556	$1,682,028	$ 725	$(1,619,225)	$1,945,412
Liabilities and Stockholders' Equity						
Current liabilities						
Trade accounts payable	$ —	$ 388	$ 7,079	$ —	$ —	$ 7,467
Oil and gas sales payable	—	—	32,408	—	—	32,408
Accrued liabilities	—	15,741	11,600	—	—	27,341
Commodity derivative liabilities	—	11	—	—	—	11
Asset retirement obligations	—	—	679	—	—	679
Intercompany payable	—	—	1,391,838	2,434	(1,394,272)	—
Total current liabilities	—	16,140	1,443,604	2,434	(1,394,272)	67,906
Long-term debt	—	847,912	—	—	—	847,912
Deferred revenue	—	11,417	—	—	—	11,417
Asset retirement obligations	—	—	20,301	—	—	20,301
Liability under tax receivable agreement	38,052	—	—	—	—	38,052
Deferred tax liabilities	19,280	3,692	—	—	—	22,972
Total liabilities	57,332	879,161	1,463,905	2,434	(1,394,272)	1,008,560
Stockholders' / members' equity						
Members' equity	—	545,395	218,123	(1,709)	(761,809)	—
Class A common stock, $0.001 par value; 30,573,509 shares issued and 30,550,907 shares outstanding	31	—	—	—	—	31
Class B common stock, $0.001 par value; 31,273,130 shares issued and outstanding	31	—	—	—	—	31
Treasury stock, at cost: 22,602 shares	(358)	—	—	—	—	(358)
Additional paid-in-capital	363,723	—	—	—	—	363,723
Retained earnings	36,569	—	—	—	—	36,569
Stockholders' equity	399,996	545,395	218,123	(1,709)	(761,809)	399,996
Non-controlling interest	—	—	—	—	536,856	536,856
Total stockholders' equity	399,996	545,395	218,123	(1,709)	(224,953)	936,852
Total liabilities and stockholders' equity	$457,328	$1,424,556	$1,682,028	$ 725	$(1,619,225)	$1,945,412

Jones Energy, Inc.

Condensed Consolidating Balance Sheet

December 31, 2014

(in thousands of dollars)	JEI(Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets						
Current assets						
Cash	$ 100	$ 1,000	$ 12,436	$ 30	$ —	$ 13,566
Restricted Cash	—	—	149	—	—	149
Accounts receivable, net						
Oil and gas sales	—	—	51,482	—	—	51,482
Joint interest owners	—	—	41,761	—	—	41,761
Other	102	8,788	3,622	—	—	12,512
Commodity derivative assets	—	121,519	—	—	—	121,519
Other current assets	—	451	2,923	—	—	3,374
Intercompany receivable	4,164	1,203,978	—	—	(1,208,142)	—
Total current assets	4,366	1,335,736	112,373	30	(1,208,142)	244,363
Oil and gas properties, net, at cost under the successful efforts method	—	—	1,638,860	—	—	1,638,860
Other property, plant and equipment, net	—	—	3,252	796	—	4,048
Commodity derivative assets	—	87,055	—	—	—	87,055
Other assets	—	20,098	254	—	—	20,352
Deferred tax assets	171	—	—	—	—	171
Investment in subsidiaries	233,908	—	—	—	(233,908)	—
Total assets	$238,445	$1,442,889	$1,754,739	$ 826	$(1,442,050)	$1,994,849
Liabilities and Stockholders' Equity						
Current liabilities						
Trade accounts payable	$ —	$ 288	$ 136,049	$ —	$ —	$ 136,337
Oil and gas sales payable	—	—	70,469	—	—	70,469
Accrued liabilities	—	8,914	10,487	—	—	19,401
Asset retirement obligations	—	—	3,074	—	—	3,074
Intercompany payable	—	—	1,209,630	2,328	(1,211,958)	—
Total current liabilities	—	9,202	1,429,709	2,328	(1,211,958)	229,281
Long-term debt	—	860,000	—	—	—	860,000
Deferred revenue	—	13,377	—	—	—	13,377
Commodity derivative liabilities	—	28	—	—	—	28
Asset retirement obligations	—	—	10,536	—	—	10,536
Liability under tax receivable agreement	803	—	—	—	—	803
Deferred tax liabilities	20,237	7,237	—	—	—	27,474
Total liabilities	21,040	889,844	1,440,245	2,328	(1,211,958)	1,141,499
Stockholders' / members' equity						
Members' equity	—	553,045	314,494	(1,502)	(866,037)	—
Class A common stock, $0.001 par value; 12,672,260 shares issued and 12,649,658 shares outstanding	13	—	—	—	—	13
Class B common stock, $0.001 par value; 36,719,499 shares issued and outstanding	37	—	—	—	—	37
Treasury stock, at cost: 22,602 shares	(358)	—	—	—	—	(358)
Additional paid-in-capital	178,763	—	—	—	—	178,763
Retained earnings	38,950	—	—	—	—	38,950
Stockholders' equity	217,405	553,045	314,494	(1,502)	(866,037)	217,405
Non-controlling interest	—	—	—	—	635,945	635,945
Total stockholders' equity	217,405	553,045	314,494	(1,502)	(230,092)	853,350
Total liabilities and stockholders' equity	$238,445	$1,442,889	$1,754,739	$ 826	$(1,442,050)	$1,994,849

Jones Energy, Inc.

Condensed Consolidating Statement of Operations

Year Ended December 31, 2015

(in thousands of dollars)	JEI (Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Operating revenues						
Oil and gas sales	$ —	$ —	$194,555	$ —	$ —	$ 194,555
Other revenues	—	1,960	884	—	—	2,844
Total operating revenues	—	1,960	195,439	—	—	197,399
Operating costs and expenses						
Lease operating	—	—	41,027	—	—	41,027
Production and ad valorem taxes	—	—	12,130	—	—	12,130
Exploration	—	—	6,551	—	—	6,551
Depletion, depreciation and amortization	—	—	205,407	91	—	205,498
Accretion of ARO liability	—	—	1,087	—	—	1,087
General and administrative	—	13,565	19,707	116	—	33,388
Other operating	—	—	4,188	—	—	4,188
Total operating expenses	—	13,565	290,097	207	—	303,869
Operating income (loss)	—	(11,605)	(94,658)	(207)	—	(106,470)
Other income (expense)						
Interest expense	—	(59,991)	(1,298)	—	—	(61,289)
Net gain on commodity derivatives	—	158,753	—	—	—	158,753
Other income (expense)	1,984	(4,832)	(4)	—	—	(2,852)
Other income (expense), net	1,984	93,930	(1,302)	—	—	94,612
Income (loss) before income tax	1,984	82,325	(95,960)	(207)	—	(11,858)
Equity interest in income	(4,728)	—	—	—	4,728	—
Income tax provision						
Current	—	113	—	—	—	113
Deferred	(363)	(2,531)	—	—	—	(2,894)
Total Income tax provision (benefit)	(363)	(2,418)	—	—	—	(2,781)
Net income (loss)	(2,381)	84,743	(95,960)	(207)	4,728	(9,077)
Net income (loss) attributable to non-controlling interests	—	—	—	—	(6,696)	(6,696)
Net income (loss) attributable to controlling interests	$(2,381)	$ —	$ —	$ —	$ —	$ (2,381)

Jones Energy, Inc.
Condensed Consolidating Statement of Operations
Year Ended December 31, 2014

(in thousands of dollars)	JEI (Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Operating revenues						
Oil and gas sales	$ —	$ —	$378,401	$ —	$ —	$378,401
Other revenues	—	1,154	1,042	—	—	2,196
Total operating revenues	—	1,154	379,443	—	—	380,597
Operating costs and expenses						
Lease operating	—	—	37,760	—	—	37,760
Production and ad valorem taxes	—	—	22,556	—	—	22,556
Exploration	—	—	3,453	—	—	3,453
Depletion, depreciation and amortization	—	—	181,578	91	—	181,669
Accretion of ARO liability	—	—	770	—	—	770
General and administrative	—	4,493	21,181	89	—	25,763
Other operating	—	—	—	—	—	—
Total operating expenses	—	4,493	267,298	180	—	271,971
Operating income (loss)	—	(3,339)	112,145	(180)	—	108,626
Other income (expense)						
Interest expense	—	(37,295)	(1,510)	—	—	(38,805)
Net gain on commodity derivatives	—	189,641	—	—	—	189,641
Other income (expense)	—	(7,921)	297	—	—	(7,624)
Other income (expense), net	—	144,425	(1,213)	—	—	143,212
Income (loss) before income tax	—	141,086	110,932	(180)	—	251,838
Equity interest in income	63,197	—	—	—	(63,197)	—
Income tax provision						
Current	53	—	—	—	—	53
Deferred	22,008	4,157	—	—	—	26,165
Total income tax provision	22,061	4,157	—	—	—	26,218
Net income (loss)	41,136	136,929	110,932	(180)	(63,197)	225,620
Net income (loss) attributable to non-controlling interests	—	—	—	—	184,484	184,484
Net income (loss) attributable to controlling interests	$41,136	$ —	$ —	$ —	$ —	$ 41,136

Jones Energy, Inc.
Condensed Consolidating Statement of Operations
Year Ended December 31, 2013

(in thousands of dollars)	JEI (Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Operating revenues						
Oil and gas sales	$ —	$ —	$258,063	$ —	$ —	$258,063
Other revenues	—	469	637	—	—	1,106
Total operating revenues	—	469	258,700	—	—	259,169
Operating costs and expenses						
Lease operating	—	—	25,129	—	—	25,129
Production and ad valorem taxes	—	—	15,517	—	—	15,517
Exploration	—	—	16,125	—	—	16,125
Depletion, depreciation and amortization	—	—	114,046	90	—	114,136
Accretion of ARO liability	—	—	608	—	—	608
General and administrative	—	4,154	27,490	258	—	31,902
Other operating	—	—	—	—	—	—
Total operating expenses	—	4,154	198,915	348	—	203,417
Operating income (loss)	—	(3,685)	59,785	(348)	—	55,752
Other income (expense)						
Interest expense	—	(26,288)	(1,121)	—	—	(27,409)
Net gain on commodity derivatives	—	(2,566)	—	—	—	(2,566)
Other income (expense)	—	(3,365)	41	(119)	—	(3,443)
Other income (expense), net	—	(32,219)	(1,080)	(119)	—	(33,418)
Income (loss) before income tax	—	(35,904)	58,705	(467)	—	22,334
Equity interest in income	(3,400)	—	—	—	3,400	—
Income tax provision						
Current	85	—	—	—	—	85
Deferred	(1,299)	1,143	—	—	—	(156)
Total income tax provision	(1,214)	1,143	—	—	—	(71)
Net income (loss)	(2,186)	(37,047)	58,705	(467)	3,400	22,405
Net income (loss) attributable to non-controlling interests	—	—	—	—	24,591	24,591
Net income (loss) attributable to controlling interests	$(2,186)	$ —	$ —	$ —	$ —	$ (2,186)

Jones Energy, Inc.
Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2015

(in thousands of dollars)	JEI (Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows from operating activities						
Net income (loss)	$ (2,381)	$ 84,743	$ (95,960)	$(207)	$ 4,728	$ (9,077)
Adjustments to reconcile net income (loss) to net cash provided by operating activities	(120,398)	(202,359)	405,395	197	(4,728)	78,107
Net cash (used in) / provided by operations	(122,779)	(117,616)	309,435	(10)	—	69,030
Cash flows from investing activities						
Additions to oil and gas properties	—	—	(311,305)	—	—	(311,305)
Proceeds from sales of assets	—	—	41	—	—	41
Acquisition of other property, plant and equipment	—	—	(1,101)	—	—	(1,101)
Current period settlements of matured derivative contracts	—	144,145	—	—	—	144,145
Change in restricted cash	—	—	(181)	—	—	(181)
Net cash (used in) / provided by investing	—	144,145	(312,546)	—	—	(168,401)
Cash flows from financing activities						
Proceeds from issuance of long-term debt	—	85,000	—	—	—	85,000
Repayment under long-term debt	—	(335,000)	—	—	—	(335,000)
Proceeds from senior notes	—	236,475	—	—	—	236,475
Payment of debt issuance costs	—	(1,556)	—	—	—	(1,556)
Proceeds from sale of common stock	122,779	—	—	—	—	122,779
Net cash (used in) / provided by financing	122,779	(15,081)	—	—	—	107,698
Net increase (decrease) in cash	—	11,448	(3,111)	(10)	—	8,327
Cash						
Beginning of period	100	1,000	12,436	30	—	13,566
End of period	$ 100	$ 12,448	$ 9,325	$ 20	$ —	$ 21,893

Jones Energy, Inc.
Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2014

(in thousands of dollars)	JEI (Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows from operating activities						
Net income (loss)	$ 41,136	$ 136,929	$ 110,932	$(180)	$(63,197)	$ 225,620
Adjustments to reconcile net income (loss) to net cash provided by operating activities	(40,778)	(326,859)	344,103	140	63,197	39,803
Net cash (used in) / provided by operations	358	(189,930)	455,035	(40)	—	265,423
Cash flows from investing activities						
Additions to oil and gas properties	—	—	(474,619)	—	—	(474,619)
Net adjustments to purchase price of properties acquired	—	—	15,709	—	—	15,709
Proceeds from sales of assets	—	—	448	—	—	448
Acquisition of other property, plant and equipment	—	—	(1,683)	—	—	(1,683)
Current period settlements of matured derivative contracts	—	(3,654)	—	—	—	(3,654)
Change in restricted cash	—	—	(104)	—	—	(104)
Net cash (used in) / provided by investing	—	(3,654)	(460,249)	—	—	(463,903)
Cash flows from financing activities						
Proceeds from issuance of long-term debt	—	170,000	—	—	—	170,000
Repayment under long-term debt	—	(468,000)	—	—	—	(468,000)
Proceeds from senior notes	—	500,000	—	—	—	500,000
Purchases of treasury stock	(358)	—	—	—	—	(358)
Payment of debt issuance costs	—	(13,416)	—	—	—	(13,416)
Net cash (used in) / provided by financing	(358)	188,584	—	—	—	188,226
Net increase (decrease) in cash	—	(5,000)	(5,214)	(40)	—	(10,254)
Cash						
Beginning of period	100	6,000	17,650	70	—	23,820
End of period	$ 100	$ 1,000	$ 12,436	$ 30	$ —	$ 13,566

Jones Energy, Inc.
Condensed Consolidating Statement of Cash Flows
Year Ended December 31, 2013

(in thousands of dollars)	JEI (Parent)	Issuers	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Cash flows from operating activities						
Net income (loss)	$ (2,186)	$ (37,047)	$ 58,705	$(467)	$ 3,400	$ 22,405
Adjustments to reconcile net income (loss) to net cash provided by operating activities	2,286	(189,393)	315,942	733	(3,400)	126,168
Net cash (used in) / provided by operations	100	(226,440)	374,647	266	—	148,573
Cash flows from investing activities						
Investment in subsidiary	(172,481)	—	—	—	172,481	—
Additions to oil and gas properties	—	—	(197,618)	—	—	(197,618)
Acquisitions of properties	—	—	(178,173)	—	—	(178,173)
Proceeds from sales of assets	—	—	963	644	—	1,607
Acquisition of other property, plant and equipment	—	—	(724)	(910)	—	(1,634)
Current period settlements of matured derivative contracts	—	7,586	—	—	—	7,586
Change in restricted cash	—	—	(45)	—	—	(45)
Net cash (used in) / provided by investing	(172,481)	7,586	(375,597)	(266)	172,481	(368,277)
Cash flows from financing activities						
Proceeds from investment in JEI	—	172,481	—	—	(172,481)	—
Proceeds from issuance of long-term debt	—	220,000	—	—	—	220,000
Repayment under long-term debt	—	(172,000)	—	—	—	(172,000)
Proceeds from sale of common stock	172,481	—	—	—	—	172,481
Payment of debt issuance costs	—	(683)	—	—	—	(683)
Net cash (used in) / provided by financing	172,481	219,798	—	—	(172,481)	219,798
Net increase (decrease) in cash	100	944	(950)	—	—	94
Cash						
Beginning of period	—	5,056	18,600	70	—	23,726
End of period	$ 100	$ 6,000	$ 17,650	$ 70	$ —	$ 23,820

Jones Energy, Inc.
Supplemental Information on Oil and Gas Producing Activities (Unaudited)

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)	2015	2014	2013
Property acquisitions:			
Unproved	$ 4,036	$ 20,030	$ 35,943
Proved	—	10,101	142,230
Exploration	6,551	3,453	16,125
Development	202,342	488,076	240,412
Total costs incurred(1)	$212,929	$521,660	$434,710

(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)	2015	2014
Unproved properties	$ 75,308	$ 94,526
Proved properties	2,320,992	2,095,396
	2,396,300	2,189,922
Accumulated depletion and impairment	(760,534)	(551,062)
Net capitalized costs	$1,635,766	$1,638,860

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, 2015, 2014 and 2013. 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 developed reserves are those reserves expected to be recovered through existing wells with existing equipment and operating methods.

	Crude Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBoe)(1)
Estimated Proved Reserves				
December 31, 2012	12,540	34,746	228,080	85,300
Extensions and discoveries	3,786	5,710	39,799	16,129
Production	(1,557)	(1,724)	(17,575)	(6,210)
Purchases of minerals in place	3,275	4,418	35,023	13,530
Sales of minerals in place	—	—	583	97
Revisions of previous estimates	(1,356)	(10,235)	(49,262)	(19,801)
December 31, 2013	16,688	32,915	236,648	89,045
Extensions and discoveries	9,295	8,675	59,248	27,844
Production	(2,475)	(2,345)	(21,922)	(8,474)
Purchases of minerals in place	3,180	3,073	22,943	10,077
Sales of minerals in place	—	—	—	—
Revisions of previous estimates	995	(3,448)	(4,640)	(3,226)
December 31, 2014	27,683	38,870	292,277	115,266
Extensions and discoveries	1,793	1,691	11,793	5,450
Production	(2,582)	(2,618)	(23,839)	(9,174)
Purchases of minerals in place	—	—	—	—
Sales of minerals in place	—	—	—	—
Revisions of previous estimates	(1,486)	(5,294)	(18,635)	(9,885)
December 31, 2015	25,408	32,649	261,596	101,657

(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, 2015, the Company added 5,450 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 9,174 MBoe. No purchases or sales of minerals in place occurred during the year ended December 31, 2015.

For the year ended December 31, 2015, the Company had net negative revisions of 9,885 MBoe, of which 56,330 MBoe was related to commodity pricing. The remaining net positive revisions of 46,445 MBoe were primarily related to reduced future development costs and production performance improvements.

For the year ended December 31, 2014, the Company added 27,844 MBoe through extensions, which represent the conversion of unproved reserves to proved reserves as a result of our continued drilling activity throughout the year. There were no discoveries of proved reserves. The Company's estimated proved reserves were reduced by current year production of 8,474 MBoe. The Company added 10,077 MBoe through the purchases of minerals in place. Purchases were primarily related to leasing in the Anadarko basin with associated Cleveland proved reserves. No sales of minerals in place occurred during the year ended December 31, 2014.

For the year ended December 31, 2014, the Company had net negative revisions of 3,226 MBoe, of which 3,534 MBoe was related to production performance in the Woodford basin. The remaining net

positive revisions of 308 MBoe were primarily related to production performance in the Cleveland basin and other changes.

For the year ended December 31, 2013, the Company added 16,129 MBoe through extensions, which represent the conversion of unproved reserves to proved reserves as a result of our continued drilling activity throughout the year. There were no discoveries of proved reserves. The Company's estimated proved reserves were reduced by current year production of 6,210 MBoe. The Company added 13,530 MBoe through the purchases of minerals in place. Purchases were primarily related to properties from the Sabine acquisition. The Company's estimated proved reserves were reduced by the sales of minerals in place. Sales were primarily related to remaining properties in the Barnett Shale.

For the year ended December 31, 2013, the Company had net negative revisions of 19,801 MBoe, of which 15,518 MBoe was related to the expiration of the Company's JDA with Southridge. The remaining net negative revisions of 4,283 MBoe were due to a combination of production performance in the Cleveland and Woodford, prices and other changes.

	Crude Oil (MBbls)	NGL (MBbls)	Natural Gas (MMcf)	Total (MBoe)(1)
Estimated Proved Reserves				
December 31, 2013				
Proved developed	7,129	19,101	139,623	49,501
Proved undeveloped	9,559	13,814	97,025	39,544
Total proved reserves	16,688	32,915	236,648	89,045
December 31, 2014				
Proved developed	10,773	22,555	160,877	60,141
Proved undeveloped	16,910	16,315	131,400	55,125
Total proved reserves	27,683	38,870	292,277	115,266
December 31, 2015				
Proved developed	11,032	19,670	169,651	58,977
Proved undeveloped	14,376	12,980	91,945	42,680
Total proved reserves	25,408	32,649	261,596	101,657

(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, 2015, 2014 and 2013. Future cash inflows do not reflect the impact of open hedge positions. Future cash inflows were reduced by 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)	2015	2014	2013
Future cash inflows	$2,373,971	$ 5,038,212	$3,213,718
Less related future:			
Production costs	(821,773)	(1,216,184)	(734,974)
Development costs	(483,060)	(939,652)	(549,343)
Income tax expense	(31,537)	(199,727)	(129,497)
Future net cash flows	1,037,601	2,682,649	1,799,904
10% annual discount for estimated timing of cash flows	(572,821)	(1,294,553)	(859,395)
Standardized measure of discounted future net cash flows	$ 464,780	$ 1,388,096	$ 940,509

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)	2015	2014	2013
Balance, beginning of period	$ 1,388,096	$ 940,509	$ 782,020
Net change in sales and transfer prices, net of production expenses	(1,063,248)	98,647	77,280
Changes in estimated future development costs	96,408	(96,245)	(9,706)
Sales and transfers of oil and gas produced during the period	(176,301)	(382,202)	(224,739)
Net change due to extensions and discoveries	6,236	442,340	239,844
Net change due to purchases of minerals in place	—	118,562	149,619
Net change due to sales of minerals in place	—	—	(337)
Net change due to revisions in quantity estimates	(153,689)	43,032	(168,438)
Previously estimated development costs incurred during the period	143,560	163,739	110,783
Net change in income taxes	108,409	(36,514)	(76,965)
Accretion of discount	120,047	94,051	59,621
Other	(4,738)	2,177	1,527
Balance, end of period	$ 464,780	$1,388,096	$ 940,509

Supplemental Quarterly Financial Information (Unaudited)

Following is a summary of the Company's results of operations by quarter for the years ended December 31, 2015, 2014 and 2013.

	2015				
(in thousands except per share data)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
Revenues	$ 58,096	$ 53,917	$ 47,152	$ 38,234	$ 197,399
Operating income (loss)	(21,838)	(23,531)	(32,393)	(28,708)	(106,470)
Net income (loss)	5,696	(51,180)	34,842	1,565	(9,077)
Net income (loss) attributable to non-controlling interests	3,508	(32,737)	21,604	929	(6,696)
Net income (loss) attributable to controlling interests	2,188	(18,443)	13,238	636	(2,381)
Basic earnings per share	$ 0.12	$ (0.66)	$ 0.44	$ 0.02	$ (0.09)
Diluted earnings per share	$ 0.12	$ (0.66)	$ 0.44	$ 0.02	$ (0.09)

	2014				
(in thousands except per share data)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
Revenues	$98,244	$106,390	$100,346	$ 75,617	$380,597
Operating income	34,017	36,114	26,231	12,264	108,626
Net income (loss)	7,708	(11,454)	50,025	179,343	225,620
Net income (loss) attributable to non-controlling interests	6,339	(9,397)	40,893	146,649	184,484
Net income (loss) attributable to controlling interests	1,369	(2,057)	9,132	32,692	41,136
Basic earnings per share	$ 0.11	$ (0.16)	$ 0.73	$ 2.60	$ 3.28
Diluted earnings per share	$ 0.11	$ (0.16)	$ 0.73	$ 2.60	$ 3.28

	2013				
(in thousands except per share data)	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Full Year
Revenues	$55,480	$64,526	$ 68,851	$70,312	$259,169
Operating income	18,047	20,251	12,095	5,359	55,752
Net income (loss)	(1,452)	48,417	(15,483)	(9,077)	22,405
Net income (loss) attributable to non-controlling interests			(14,623)	(7,751)	24,591
Net loss attributable to controlling interests			(860)	(1,326)	(2,186)
Basic earnings (loss) per share			$ (0.07)	$ (0.10)	$ (0.17)
Diluted earnings (loss) per share			$ (0.07)	$ (0.10)	$ (0.17)

(This page has been left blank intentionally.)

(This page has been left blank intentionally.)

(This page has been left blank intentionally.)

Forward-Looking Statement

This annual report contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All statements, other than statements of historical fact, included in this annual report that address activities, events or developments that the Company expects, believes or anticipates will or may occur in the future are forward-looking statements. Without limiting the generality of the foregoing, forward-looking statements contained in the annual report specifically include the expectations of plans, strategies, objectives and anticipated operating results of the Company, including guidance regarding the impact of hedging activities on the Company's future cash flow and the Company's ability to capitalize on opportunities in the current commodity price environment. These statements are based on certain assumptions made by the Company based on management's experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements and are described in further detail in the Company's Annual Report on Form 10-K. Any forward-looking statements speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

Executive Team

Jonny Jones
Founder, Chairman & Chief Executive Officer

Mike S. McConnell
President

Robert J. Brooks
Executive Vice President & Chief Financial Officer

Eric Niccum
Executive Vice President & Chief Operating Officer

Jeff Tanner
Executive Vice President - Geosciences

Board of Directors

Jonny Jones
Chairman

Alan D. Bell
Director

Howard I. Hoffen
Director

Mike S. McConnell
Director

Gregory D. Myers
Director

Robb L. Voyles
Director

Halbert S. Washburn
Director

Corporate Headquarters

Jones Energy, Inc.
807 Las Cimas Parkway, Suite 350
Austin, Texas 78746
Phone: 512.328.2953
Fax: 512.328.5394

Transfer Agent

American Stock Transfer and Trust Company
6201 15th Avenue
Brooklyn, NY 11219
www.amstock.com

Stock Exchange

Common stock traded on the New York Stock Exchange under the symbol: JONE

Form 10-K

For an additional copy of the Annual Report on Form 10-K, please contact:
Jones Energy, Inc.
Investor Relations Department
Phone: 512.328.2953
Email: ir@jonesenergy.com

Website Address

www.jonesenergy.com

Annual Meeting

The Annual Meeting for Jones Energy, Inc. shareholders will be held at our corporate headquarters in Austin, Texas on May 4, 2016.

JONES
ENERGY

807 Las Cimas Parkway, Suite 350
Austin, Texas 78746