SUBJECT TO COMPLETION, DATED JANUARY 17, 2017

PROSPECTUS

38,225,000 Shares

Jagged Peak Energy Inc.

Common stock

This is the initial public offering of our common stock. We are selling 26,470,588 shares of our common stock, and the selling stockholders are selling 11,754,412 shares of our common stock. We will not receive any proceeds from the shares of our common stock sold by the selling stockholders.

Prior to this offering, there has been no public market for our common stock. The initial public offering price of the common stock is expected to be between $16.00 and $18.00 per share. We have been authorized to list our common stock on the New York Stock Exchange under the symbol "JAG".

To the extent that the underwriters sell more than 38,225,000 shares of common stock, the underwriters have the option to purchase up to an additional 5,733,750 shares from Quantum (as defined herein) at the public offering price less the underwriting discount and commissions.

We are an "emerging growth company" as that term is used in the Jumpstart Our Business Startups Act of 2012, and as such, we have elected to take advantage of certain reduced public company reporting requirements for this prospectus and future filings. See "Risk Factors" and "Summary—Emerging Growth Company".

Investing in our common stock involves risks. See "Risk Factors" beginning on page 22.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The underwriters expect to deliver the shares to purchasers on or about , 2017 through the book-entry facilities of The Depository Trust Company.

	Per Share	Total
Public Offering Price	$	$
Underwriting Discount(1)	$	$
Proceeds to Jagged Peak Energy Inc. (before expenses)	$	$
Proceeds to the Selling Stockholders	$	$

(1) The underwriters will also be reimbursed for certain expenses incurred in the offering. See "Underwriting (Conflicts of Interest)" for additional information regarding underwriting compensation.

Joint Book-Running Managers

Citigroup **Credit Suisse** **J.P. Morgan**

Goldman, Sachs & Co. **RBC Capital Markets** **Wells Fargo Securities**

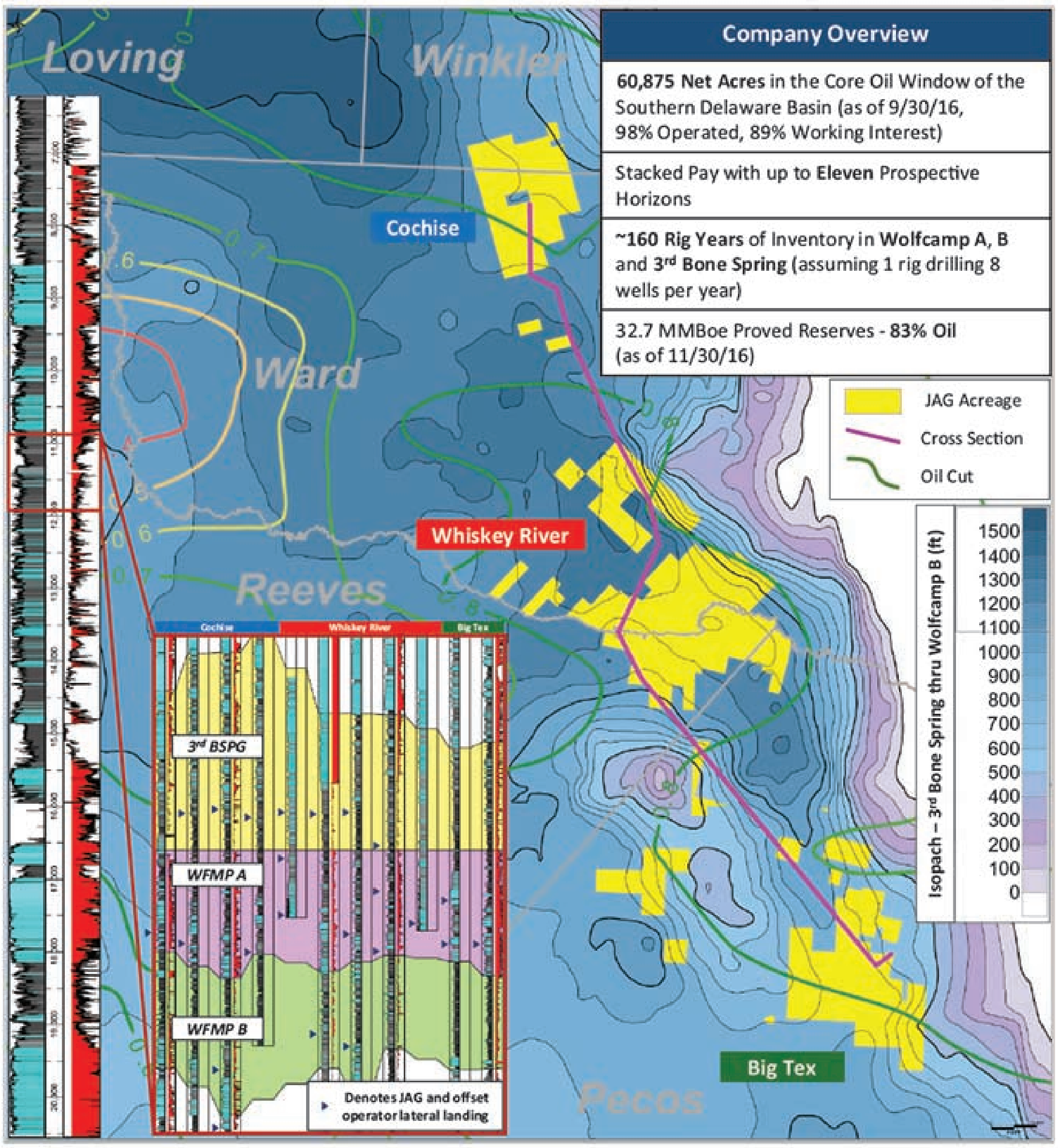
Senior Co-Managers

UBS Investment Bank **KeyBanc Capital Markets**

Co-Managers

ABN AMRO **Fifth Third Securities** **Petrie Partners Securities** **Tudor, Pickering, Holt & Co.**
BMO Capital Markets **Deutsche Bank Securities** **Evercore ISI** **Scotia Howard Weil**

The date of this prospectus is , 2017.


Company Overview
60,875 Net Acres in the Core Oil Window of the Southern Delaware Basin (as of 9/30/16, 98% Operated, 89% Working Interest)
Stacked Pay with up to Eleven Prospective Horizons
~160 Rig Years of Inventory in Wolfcamp A, B and 3rd Bone Spring (assuming 1 rig drilling 8 wells per year)
32.7 MMBoe Proved Reserves - 83% Oil (as of 11/30/16)
JAG Acreage
Cross Section
Oil Cut
Isopach – 3rd Bone Spring thru Wolfcamp B (ft)
1500
1400
1300
1200
1100
1000
900
800
700
600
500
400
300
200
100
0
Loving
Winkler
Ward
Reeves
Pecos
Cochise
Whiskey River
Big Tex
3rd BSPG
WFMP A
WFMP B
Denotes JAG and offset operator lateral landing

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You should rely only on the information contained in this prospectus and any free writing prospectus prepared by us or on behalf of us or the information to which we have referred you. Neither we, the selling stockholders nor the underwriters have authorized anyone to provide you with information different from that contained in this prospectus and any free writing prospectus. We take no responsibility for, and can provide no assurance as to the reliability of, any other information that others may give you. We, the selling stockholders and the underwriters are offering to sell shares of common stock and seeking offers to buy shares of common stock only in jurisdictions where offers and sales are permitted. The information in this prospectus is accurate only as of the date of this prospectus, regardless of the time of delivery of this prospectus or any sale of the common stock. Our business, financial condition, results of operations and prospects may have changed since that date.

This prospectus contains forward-looking statements that are subject to a number of risks and uncertainties, many of which are beyond our control. See "Risk Factors" and "Cautionary Statement Regarding Forward-Looking Statements".

Until , 2017 (25 days after commencement of this offering), all dealers that effect transactions in these securities, whether or not participating in this offering, may be required to deliver a prospectus. This is in addition to the dealer's obligation to deliver a prospectus when acting as an underwriter and with respect to unsold allotments or subscriptions.

Commonly Used Defined Terms

As used in this prospectus, unless the context indicates or otherwise requires, the terms listed below have the following meanings:

- "Jagged Peak", the "Company", "us", "we", "our" or "ours" or like terms refer to Jagged Peak Energy LLC before the completion of our corporate reorganization described in "Corporate Reorganization", and to Jagged Peak Energy Inc. following the completion of our corporate reorganization;
- "Quantum" refers, as applicable, to Quantum Energy Partners and its affiliates, including Q-Jagged Peak Energy Investment Partners, LLC;
- "Management Members" refers, collectively, to our current and former officers and employees who own equity interests in Jagged Peak Energy LLC;
- "Existing Owners" refers, collectively, to Q-Jagged Peak Energy Investment Partners, LLC and the Management Members; and
- "Management Holdco" refers to JPE Management Holdings LLC, a Delaware limited liability company, which will be formed to hold shares of our common stock that will be distributed in respect of certain management incentive units in Jagged Peak Energy LLC held by our officers and other employees, as further described under "Corporate Reorganization".

Industry and Market Data

The market data and certain other statistical information used throughout this prospectus are based on independent industry publications, government publications and other published independent sources. Although we believe these third-party sources are reliable as of their respective dates, neither we, the selling stockholders nor the underwriters have independently verified the accuracy or completeness of this information. Some data is also based on our good faith estimates. The industry in which we operate is subject to a high degree of uncertainty and risk due to a variety of factors, including those described in the section entitled "Risk Factors". These and other factors could cause results to differ materially from those expressed in these publications.

Trademarks and Trade Names

We own or have rights to various trademarks, service marks and trade names that we use in connection with the operation of our business. This prospectus may also contain trademarks, service marks and trade names of third parties, which are the property of their respective owners. Our use or display of third parties' trademarks, service marks, trade names or products in this prospectus is not intended to, and does not imply, a relationship with us or an endorsement or sponsorship by or of us. Solely for convenience, the trademarks, service marks and trade names referred to in this prospectus may appear without the ®, TM or SM symbols, but such references are not intended to indicate, in any way, that we will not assert, to the fullest extent under applicable law, our rights or the right of the applicable licensor to these trademarks, service marks and trade names.

SUMMARY

This summary highlights information contained elsewhere in this prospectus. You should read the entire prospectus carefully, including the information under the headings "Risk Factors", "Cautionary Statement Regarding Forward-Looking Statements" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the financial statements and the notes to those financial statements appearing elsewhere in this prospectus. The information presented in this prospectus assumes (i) an initial public offering price of $17.00 per common share (the midpoint of the price range set forth on the cover of this prospectus) and (ii) unless otherwise indicated, that the underwriters do not exercise their option to purchase additional shares of common stock.

Unless indicated otherwise or the context otherwise requires, references in this prospectus to "Jagged Peak", the "Company", "us", "we", "our" or "ours" refer to Jagged Peak Energy LLC before the completion of our corporate reorganization described in "Corporate Reorganization", and to Jagged Peak Energy Inc. following the completion of our corporate reorganization. This prospectus includes certain terms commonly used in the oil and natural gas industry, which are defined elsewhere in this prospectus in "Annex A: Glossary of Oil and Natural Gas Terms".

Our Company

Business Overview

We are a growth-oriented, independent oil and natural gas company focused on the acquisition and development of unconventional oil and associated liquids-rich natural gas reserves in the Southern Delaware Basin, a sub-basin of the Permian Basin of West Texas and one of the most prolific unconventional resource plays in North America. Our acreage is located on large, contiguous blocks in the adjacent counties of Winkler, Ward, Reeves and Pecos, with significant original oil-in-place within multiple stacked hydrocarbon-bearing formations. We are focused on increasing stockholder value by (i) growing production and reserves through the development of our multi-year inventory of 1,265 gross horizontal drilling locations with an average lateral length of 7,426 feet, (ii) expanding and improving the resource potential of our existing acreage position and (iii) growing our acreage position through acquisitions and leasing efforts.

As of September 30, 2016, we held an average 89% working interest in approximately 68,121 gross (60,875 net) leased or acquired acres, and we operated approximately 98% of our acreage position. Both our production and our proved reserves consist of greater than 80% oil. Our acreage is exclusively located in the core oil window of the Southern Delaware Basin. We generally consider the core oil window of the Southern Delaware Basin to be the eastern and southern portion of the basin, which is characterized by high oil saturation and favorable over-pressured conditions.

Jagged Peak was formed in April 2013 by an affiliate of Quantum Energy Partners, a leading energy private equity firm that has managed more than $11 billion of equity commitments since 1998, and key members of our management team. Our management and technical teams, which have extensive engineering, geoscience, land, marketing and finance capabilities, are led by Joseph N. Jaggers, an industry veteran with over 35 years of experience growing oil and natural gas operations. Mr. Jaggers and his teams have a proven track record of achieving significant production and reserve growth in unconventional plays in the United States, including at Ute Energy, LLC, where Mr. Jaggers served as President and Chief Executive Officer, and at Bill Barrett Corporation, where he served as President and Chief Operating Officer.

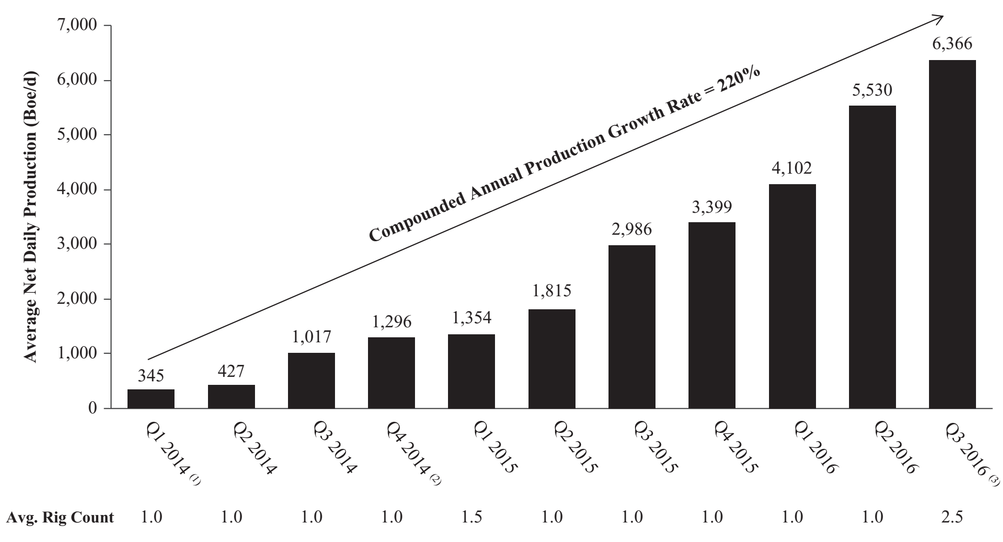
We were formed with the goal of building a premier acquisition and development company focused on horizontal drilling in the core oil window of the Southern Delaware Basin. We plan to achieve this goal by using advanced drilling and completion techniques and leveraging our management team's extensive experience and technical expertise. At our inception, we specifically targeted the Southern Delaware Basin due to the abundant amount of oil-in-place, stacked pay potential, low breakeven-prices, attractive well economics, favorable operating environment and in-place midstream infrastructure. We have assembled our current acreage position by executing privately sourced acquisitions of largely undeveloped acreage and through grassroots leasing.

As of September 30, 2016, we have drilled and completed 16 horizontal wells. Based on the wells we have drilled to date and wells drilled by other operators, we believe the Lower Wolfcamp A, Upper Wolfcamp A, Wolfcamp B and 3rd Bone Spring Sand formations are significantly delineated across our acreage. The top of the Wolfcamp formation ranges from approximately 8,850 feet to 11,420 feet, and the top of the Bone Spring formation ranges from approximately 8,600 feet to 10,900 feet. We also believe that significant additional development opportunities exist on our acreage in the Brushy Canyon, Avalon Shale, 1st Bone Spring Lime, 1st Bone Spring Sand, 2nd Bone Spring Sand, 3rd Bone Spring Lime and Wolfcamp C formations.

Our contiguous acreage position enables the drilling of long laterals, resulting in significant drilling efficiencies that enhance the economic development of our acreage position. The ability to drill long-lateral wells improves our returns by (i) increasing our EUR per well, (ii) allowing us to contact more reservoir rock with fewer vertical wellbores (thus reducing drilling and completion costs on a per unit basis) and (iii) allowing us to hold more acreage per horizontal well drilled. Additionally, the contiguous nature of our acreage provides economies of scale by allowing us to better share our infrastructure.

Since commencing our drilling program in late 2013, we have consistently increased EURs and improved our well and field-level returns by refining our landing zones, drilling longer length laterals and enhancing our completion techniques. Over the same period, we have also improved our returns by reducing our drilling times and drilling and completion costs. We expect that continued optimization in the field, employment of pad drilling and expansion of our infrastructure will further increase stockholder value.

The prolific nature of our long-lateral horizontal drilling locations and continually modified and improved completion designs have allowed us to increase our average net daily production from 345 Boe/d in the first quarter of 2014 (normalized for five days of production) to 6,366 Boe/d in the third quarter of 2016 while operating an average of one horizontal drilling rig through June 30, 2016. We began operating our second and third rigs in July of 2016 and, in 2017, we expect our drilling program to grow to six horizontal rigs, allowing us to continue our rapid production growth. Assuming this 2017 level of drilling activity, we have over 26 years of drilling inventory. The chart below shows our historical production over time.



(1) Q1 2014 production normalized for five days of production.

(2) The increase in production from Q3 2014 to Q4 2014 was partially attributable to the acquisition of three producing wells in September 2014 with average daily production of 74 Boe/d during Q4 2014.

(3) We added our second and third rigs during July 2016. There were no completions or production attributable to these rigs as of September 30, 2016.

We have made a strategic decision to construct and operate water handling infrastructure within our project areas, which allows us to consistently realize significant operating and cost efficiencies. We intend to install additional water handling infrastructure to accommodate our projected future production growth. Our infrastructure strategy includes owning a sufficient amount of surface acreage in our project areas to control both fresh water supply for drilling and completions and disposal of flowback and produced water.

As of September 30, 2016, we had identified 1,265 gross horizontal drilling locations in the Lower Wolfcamp A, the Upper Wolfcamp A, the Wolfcamp B and the 3rd Bone Spring Sand formations, assuming 880-foot spacing in an offset pattern and a minimum vertical separation of 175 feet within target formations. 69% of our identified locations are classified as long or extra-long laterals, with an average length of 8,806 feet. We expect to significantly add to our drilling inventory over time as we continue to decrease the horizontal and vertical spacing of horizontal wells, acquire additional acreage and establish the productive capability of additional zones.

We classify our acreage position into three project areas: Whiskey River, Cochise and Big Tex. As of September 30, 2016, we had drilled and completed eight operated wells in the Whiskey River project area targeting the Lower Wolfcamp A, Upper Wolfcamp A and Wolfcamp B. We had drilled and completed six operated wells in the Cochise project area targeting the Lower Wolfcamp A. We had drilled and completed two operated wells in the Big Tex project area targeting the Lower Wolfcamp A. The following table provides a summary of our gross horizontal drilling locations by project area, targeted formation and lateral length as of September 30, 2016.

Gross Identified Horizontal Drilling Locations(1)(2)(3)

	Cochise	Whiskey River	Big Tex	Totals
By Target				
3rd Bone Spring Sand	66	225	—	291
Upper Wolfcamp A	53	171	84	308
Lower Wolfcamp A	57	219	99	375
Wolfcamp B	66	225	—	291
Total Locations	242	840	183	1,265
By Lateral Length Category				
Extra Long (Two Sections)	175	355	76	606
Long (One and One-Half Sections)	46	151	72	269
Standard (One Section)	21	334	35	390
Total Locations	242	840	183	1,265
Avg. Completed Lateral Length (in feet)				
Extra Long	9,587	9,534	9,480	9,543
Long	6,900	7,273	7,041	7,147
Standard	4,290	4,358	4,071	4,328
Gross Acres	12,894	35,912	19,315	68,121
Net Acres	12,244	30,796	17,835	60,875
Avg. Working Interest	95.0%	85.8%	92.3%	89.4%

(1) Our total identified horizontal drilling locations include 26 locations associated with proved undeveloped reserves as of November 30, 2016. We have estimated our drilling locations based on well spacing assumptions and upon the evaluation of our horizontal drilling results and those of other operators in our area, combined with our interpretation of available geologic and engineering data. The drilling locations that we actually drill will depend on the availability of capital, regulatory approvals, commodity prices, costs, actual drilling results and other factors. Any drilling activities we are able to conduct on these identified locations may not be successful and may not result in additional proved reserves. Further, to the extent the drilling locations are associated with acreage that expires, we would lose our right to develop the related locations. See "Risk Factors—Risks Related to Our Business—Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill such locations".

(2) Our horizontal drilling location count implies 880-foot spacing in an offset pattern and minimum vertical separation of 175 feet.

(3) 1,186 of our 1,265 horizontal drilling locations are on acreage that we operate. We have an 89% average working interest in our acreage.

For the month ended September 30, 2016, our average net daily production was 6,601 Boe/d, of which approximately 83% was oil, 9% was NGLs and 8% was natural gas. Of this production, approximately 44%, 45% and 11% were attributable to our Cochise, Whiskey River and Big Tex project areas, respectively. The following table provides summary information regarding our proved reserves as of November 30, 2016, based on a reserve report prepared by Ryder Scott Company, L.P. (“Ryder Scott”), a third-party engineering firm.

Estimated Total Proved Reserves						
Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	% Oil	% Liquids(1)	% Developed
26.4	3.8	15.3	32.7	80.7	92.2	39.7

(1) Includes oil and NGLs.

The following table presents data on Jagged Peak’s operated horizontal wells drilled and completed since commencement of our drilling program in late 2013 through November 30, 2016.

Year of First Production	Well Count	Average Completed Lateral Length (feet)	Average Oil Equivalent EUR (2) (MBbls)	Average Oil Equivalent EUR per 1,000’ (2) (MBbls)	Average Drilling and Completion Costs per 1,000’ (in thousands)
2014(1)	3	6,556	649	99	$2,517
2015	7	9,164	950	104	1,481
2016 through 11/30	9	9,134	1,036	113	1,100

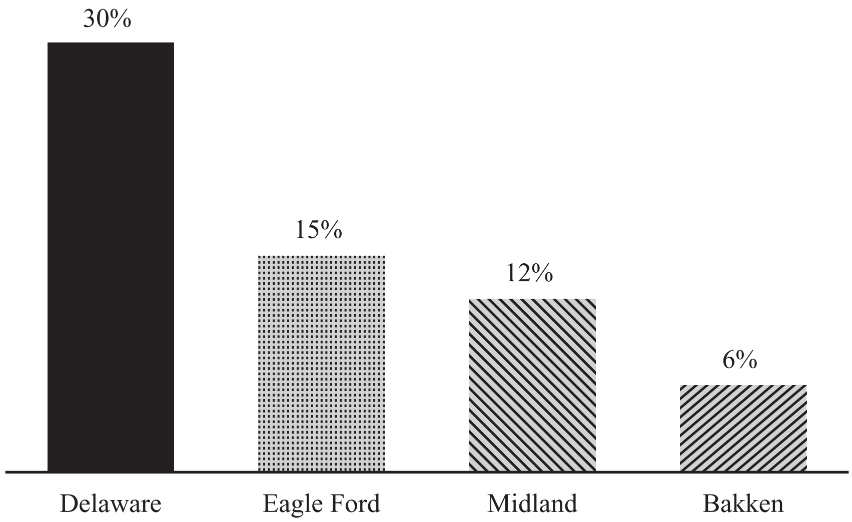
(1) Does not include the results of one well that was drilled in 2014, but was not completed in accordance with our completion design due to mechanical issues.

(2) EUR represents the sum of gross reserves remaining as of a given date and cumulative production as of that date. EUR is based on the estimated gross reserves attributable to each location in our reserve report as of November 30, 2016. Average EUR for the nine wells drilled and completed during the eleven months ended November 30, 2016, includes the results of our six most recent wells drilled and completed in our Whiskey River and Cochise project areas targeting the Wolfcamp A formation, each of which utilized the continued optimization and refinement of our advanced drilling and completion techniques. These six wells had an average EUR of 1,136 MBbls as of November 30, 2016.

The Permian Basin is an attractive operating area due to its multiple stacked hydrocarbon-bearing formations that are prospective for horizontal development. The basin is further characterized by a favorable operating environment, high oil and liquids-rich natural gas content, significant in-place midstream infrastructure, a well-developed network of oilfield service providers, long-lived reserves with consistent geologic attributes and reservoir quality and historically high development success rates. According to the Energy Information Administration of the U.S. Department of Energy, the Permian Basin is the most prolific oil producing area in the United States, accounting for 25% of total U.S. crude oil production during September 2016.

Over the past decade, the Delaware Basin has experienced significant growth in horizontal drilling activity. According to Baker Hughes, as of September 30, 2016, the Permian Basin remains the most active basin in the United States based on 167 active horizontal rigs, with the Delaware Basin representing approximately 50% of that activity. From January 2013 through September 30, 2016, production in the Delaware Basin has grown at a 30% compounded annual production growth rate, outpacing other regions in the United States, as illustrated in the following chart.

Compounded Annual Production Growth Rate for Major Oil Basins and Plays
(January 2013 to September 2016)



Source: Wood Mackenzie as of September 2016.

Business Strategies

Our primary business objective is to increase stockholder value through the execution of the following strategies:

- ***Economically grow production, cash flow and reserves by developing our extensive drilling inventory in the core oil window of the Southern Delaware Basin.*** Our technical acumen and horizontal drilling expertise have enabled us to drill highly productive horizontal wells in multiple formations. While operating an average of one horizontal drilling rig through June 30, 2016, we grew our average net daily production from 345 Boe/d in the first quarter of 2014 (normalized for five days of production) to 6,366 Boe/d in the third quarter of 2016, representing a compounded annual production growth rate of 220%. We began operating our second and third rigs in July of 2016 and, in 2017, we expect our drilling program to grow to six horizontal rigs, allowing us to continue our rapid production growth. We intend to continue to economically grow production, cash flow and reserves by utilizing our technical expertise to develop our multi-year drilling inventory while efficiently allocating capital to maximize the value of our resource base.
- ***Expand drilling inventory over time.*** In addition to the 1,265 gross horizontal locations identified in the Lower Wolfcamp A, the Upper Wolfcamp A, the Wolfcamp B and the 3rd Bone Spring Sand formations, we intend to add to our drilling inventory over time as we (i) decrease the horizontal and vertical spacing of our horizontal wells, (ii) acquire additional acreage by leveraging our technical acumen and horizontal drilling expertise to identify strategic acquisition opportunities and (iii) establish the productive capability of additional zones.
- ***Maximize returns by optimizing drilling and completion techniques through the experience and expertise of our management and technical teams.*** Our experienced management and technical teams have a proven track record of optimizing drilling and completion techniques to drive well and field-level returns. We have experienced a significant decrease in our drilling and completion costs since 2014. This trend has been driven by efficiency improvements in the field, including reduced drilling days, the modification of well designs and a continued focus on procurement throughout our operations. In addition, we believe our contiguous acreage position and our

ability to drill long-lateral wells will enhance our returns by increasing our EUR per well, reducing drilling and completion costs and providing economies of scale by allowing us to better share our infrastructure.

- ***Strategically manage infrastructure and midstream services contracts to lower our costs.*** We vigorously pursue cost reductions throughout our operations. We have made a strategic decision to construct and operate water handling infrastructure within our project areas to enable us to achieve high operating efficiency. We intend to install additional water handling infrastructure to accommodate our projected future production growth. Our oil and natural gas gathering and transportation contracts are structured as acreage dedications, which allows us to avoid incurring fees or penalties associated with minimum volume commitments.

- ***Leverage extensive industry experience to evaluate and execute strategic acquisitions.*** Our management and technical teams have an extensive track record of forming and building businesses in North American resource plays. We also have significant experience in successfully sourcing, evaluating and executing acquisition opportunities, including multiple privately sourced acquisitions that make up the majority of our current acreage position. We regularly initiate and review acquisition opportunities and intend to pursue future acquisitions that meet our strategic and financial objectives. We believe our understanding of the geology, geophysics and reservoir properties of potential acquisition targets will allow us to identify and acquire highly prospective acreage in order to grow our resource base and maximize stockholder value.

- ***Maintain a high degree of operational control.*** We seek to maintain operational control of our properties in order to better execute on our strategy of enhancing returns through operating improvements and cost efficiencies. As the operator of approximately 98% of our acreage, we are able to effectively manage (i) the timing and level of our capital spending, (ii) our development drilling strategies and (iii) our operating costs. We believe this flexibility to manage our development program allows us to optimize our field-level returns and profitability.

- ***Preserve financial flexibility to pursue organic and external growth opportunities.*** We seek to maintain a conservative financial position. We expect to fund our growth with cash flow from operations, availability under our senior secured revolving credit facility, which we will amend and restate in connection with this offering to, among other things, increase the aggregate commitments thereunder ("credit facility"), and capital markets offerings when appropriate. We intend to continue allocating capital in a disciplined manner and proactively manage our cost structure to achieve our business objectives. Consistent with our disciplined approach to financial management, we expect to maintain an active hedging program to reduce our exposure to commodity price volatility and protect our cash flow, returns and the funding of our capital program.

Our Competitive Strengths

We believe that the following strengths will allow us to successfully execute our business strategies:

- ***Attractive portfolio of contiguous acreage in the core oil window of the Southern Delaware Basin.*** Our current leasehold acreage is located in the oil-rich southern portion of the Delaware Basin in Winkler, Ward, Reeves and Pecos Counties. This acreage is characterized by a multi-year, oil-weighted inventory of horizontal drilling locations that provide attractive growth and return opportunities. As of November 30, 2016, our estimated proved reserves consisted of 80.7% oil, 11.5% NGLs and 7.8% natural gas. The extensive original oil-in-place, favorable over-pressured conditions and other attractive geologic characteristics of the Southern Delaware Basin give us a high degree of confidence in our current drilling inventory.

- ***Large horizontal drilling inventory and significant number of long-lateral wells across multiple pay formations.*** We have identified a multi-year inventory of 1,265 gross horizontal drilling locations with an average lateral length of 7,426 feet. 69% of our identified locations are classified as long or extra-long laterals, with an average length of 8,806 feet. We believe our extensive inventory of long and extra-long lateral locations will generate superior economic returns relative to shorter laterals. Assuming six rigs in operation, which is our 2017 level of budgeted drilling activity, we have over 26 years of drilling inventory. We intend to significantly add to our drilling inventory over time as we continue to reduce and refine well spacing, acquire additional acreage and establish the productive capability of additional zones.

- ***Proven horizontal drilling expertise and technical acumen in the Delaware Basin.*** We believe our horizontal drilling and multi-stage fracturing stimulation experience in the Delaware Basin provides us with a competitive strength. Since commencement of our drilling program in late 2013, we have substantially reduced drilling days for our horizontal wells. The average time from spud to rig release for our seven horizontal wells drilled during the nine months ended September 30, 2016 was approximately 42 days, compared to an average of 67 days for the thirteen horizontal wells we drilled in 2015 and 2014. In addition, we continually modify our completion design to optimize the performance of our wells and expect to realize further drilling efficiencies going forward.

- ***High degree of operational control.*** We are the operator of approximately 98% of our acreage. This operating control allows us to better execute our strategies of enhancing returns through operational and cost efficiencies and increasing ultimate hydrocarbon recovery. As the operator of substantially all of our acreage, we retain the flexibility to adjust our capital expenditures based on the prevailing commodity price environment and other factors. We also believe that our significant level of operational control will enable us to implement pad drilling and other drilling and completion optimization strategies, which will result in the continued reduction of spud-to-rig release days, engineered completion designs and efficient use of infrastructure.

- ***Highly effective and cost efficient water sourcing, transportation, storage and disposal.*** Our infrastructure strategy includes owning sufficient tracts of surface acreage to (i) allow us to control fresh water supply for drilling and completions, (ii) provide ease of pipeline installation, (iii) allow construction of storage for both fresh and produced water and (iv) simplify construction of facilities for disposal of flowback and produced water. In addition, we have supplemental agreements that provide for fresh water sourcing and produced water storage and disposal services from adjacent landowners. As of September 30, 2016, our installed and contracted capacities were (i) 4.7 million barrels of water storage capacity, (ii) 10.5 miles of fresh water pipelines and 63.6 miles of produced water transportation pipelines, which allows us to largely eliminate water trucking in all phases of our operation, (iii) 162 thousand barrels per day of water sourcing capacity and (iv) 86 thousand barrels per day of water disposal capacity. Accordingly, we have disposal capacity more than three times our current produced water volumes and sufficient sources of fresh water to support our current drilling program, and we believe it is scalable to support additional rigs. This infrastructure position provides important cost advantages compared to utilizing third-party services.

- ***Experienced and incentivized management team.*** With an average of 32 years of industry experience, our senior management team has a proven track record of building and running successful businesses focused on the acquisition and development of oil and natural gas properties and enhancing returns through operational efficiencies. Prior to forming Jagged Peak, a subset of our management team, including Joseph N. Jaggers, our Chief Executive Officer and President, and Gregory S. Hinds, our Executive Vice President, Development Planning & Acquisitions, led the growth of Ute Energy LLC's upstream oil and natural gas assets to over 7,800 Boe/d of production and over 156,800 net acres of undeveloped properties and built a natural gas gathering and processing network servicing Ute Energy and other third parties in the Uinta Basin. In November 2012, Ute Energy's upstream and midstream subsidiaries were sold for consideration in excess of $1.0 billion. We believe our team's experience building and operating multiple successful upstream oil and natural gas companies provides us with a distinct competitive advantage. Additionally, after giving effect to this offering, our management team and other employees will hold approximately 10.8% of our common stock, which provides a meaningful incentive to increase the value of our business for the benefit of all stockholders.
- ***Conservatively capitalized balance sheet and strong liquidity profile.*** After giving effect to this offering and the use of proceeds therefrom, we expect to have no outstanding debt, $180.0 million of borrowing capacity under our credit facility and approximately $294.2 million of cash on the balance sheet (based on our cash balance as of September 30, 2016). We believe our borrowing capacity, cash on hand and cash flow from operations will provide us with sufficient liquidity to execute our 2017 capital program.

Capital Program

Our 2017 capital budget for drilling, completion and recompletion activities and facilities costs is approximately $580.0 million, excluding potential acquisitions. We expect to allocate approximately $527.0 million of our 2017 capital budget for the drilling and completion of operated wells. In the nine months ended September 30, 2016, we incurred capital costs of approximately $86.6 million, excluding acquisitions. In addition, we incurred capital costs of $39.3 million for acquiring undeveloped properties.

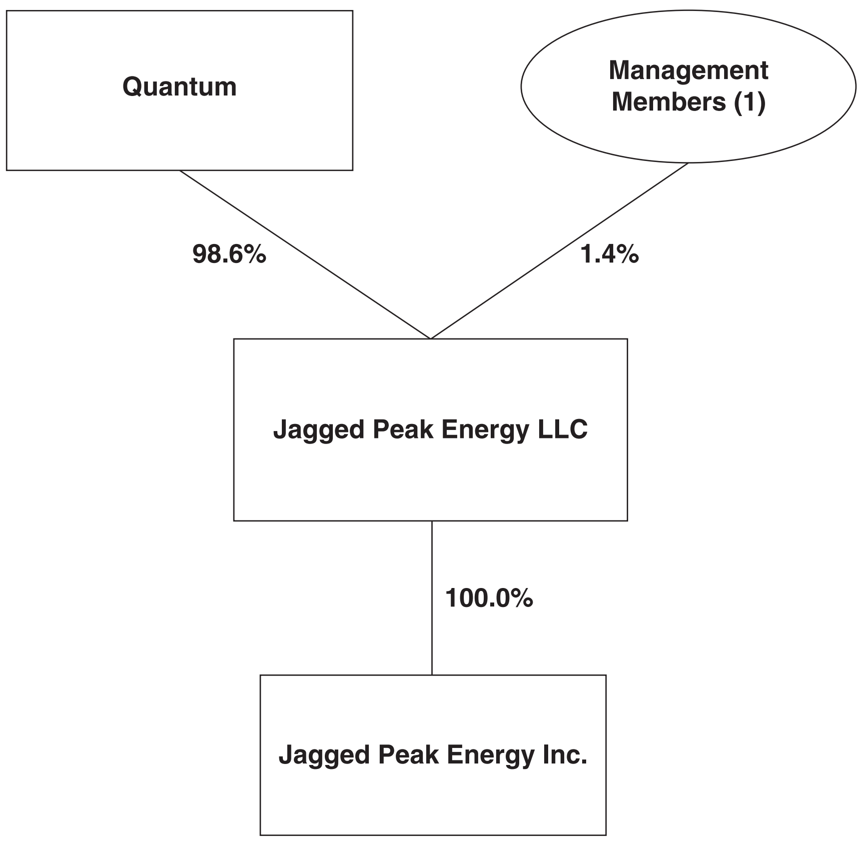
Because we operate a high percentage of our acreage, capital expenditure amounts and timing are largely discretionary and within our control. We determine our capital expenditures depending on a variety of factors, including, but not limited to, the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other working interest owners.

Corporate Reorganization

We have incorporated under the laws of the State of Delaware to become a holding company for Jagged Peak Energy LLC and its assets and operations. Jagged Peak Energy LLC, which is our accounting predecessor, was formed as a Delaware limited liability company in 2013 with equity commitments from Quantum and certain of our Management Members. The Management Members also hold management incentive units in Jagged Peak Energy LLC that entitle the holders thereof to a portion of any proceeds distributed by Jagged Peak Energy LLC following the achievement of certain return thresholds by the capital interest owners of Jagged Peak Energy LLC.

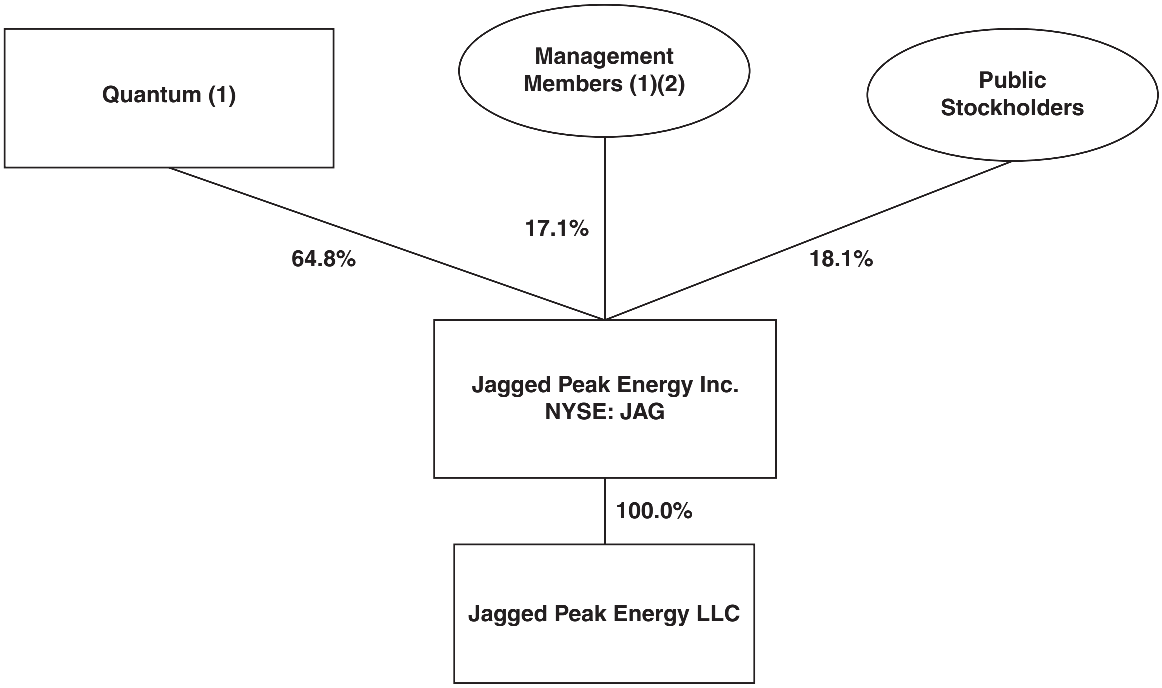
Pursuant to the terms of certain reorganization transactions that will be completed immediately prior to the closing of this offering, (i) the equity interests (both capital interests and management incentive units) in Jagged Peak Energy LLC will be recapitalized into a single class of units ("Units"), with the Units to be allocated among the Existing Owners in accordance with the terms of the limited liability company agreement of Jagged Peak Energy LLC and calculated using an implied valuation for Jagged Peak Energy LLC based on the initial public offering price of our common stock, (ii) our officers and other employees that hold management incentive units in Jagged Peak Energy LLC will contribute to Management Holdco certain of the Units issued to them in the recapitalization described above in exchange for membership interests in Management Holdco and (iii) Jagged Peak Energy LLC will merge into a subsidiary of Jagged Peak Energy Inc., and the Existing Owners and Management Holdco will receive as consideration in the merger shares of Jagged Peak Energy Inc. common stock, with such shares of common stock to be allocated among the Existing Owners and Management Holdco pro rata based on their relative ownership of Units. As a result of these transactions, Jagged Peak Energy LLC will become a wholly owned subsidiary of Jagged Peak Energy Inc. The membership interests in Management Holdco that will be issued to our officers and other employees that hold management incentive units in Jagged Peak Energy LLC in exchange for their Units will generally vest in equal installments on each of the first three anniversaries of this offering, subject to continued employment and other conditions, and will be settled in shares of our common stock upon vesting. See "Corporate Reorganization".

The following diagram indicates the current simplified ownership structure of Jagged Peak Energy LLC.



(1) Does not include management incentive units. See "Corporate Reorganization—Existing Owners' Ownership".

The following diagram indicates our simplified ownership structure after giving effect to our corporate reorganization and this offering (assuming that the underwriters' option to purchase additional shares is not exercised).



(1) Assumes an initial offering price of $17.00 per share of common stock, the midpoint of the price range set forth on the cover page of this prospectus. Any increase or decrease (as applicable) of the assumed initial public offering price will result in an increase or decrease, respectively, in the number of shares of common stock to be received by the Management Members and Management Holdco, and an equivalent decrease or increase, respectively, in the number of shares of common stock to be received by Quantum. Accordingly, any such change in our initial public offering price will not affect the aggregate number of shares of common stock held by our Existing Owners. See "Corporate Reorganization—Existing Owners' Ownership".

(2) Includes shares of common stock held by the Management Members and shares of common stock held by Management Holdco. Includes aggregate ownership by the Management Members that currently serve as our officers and other employees of approximately 10.8% of our common stock.

Our Principal Stockholder

We have a valuable relationship with Quantum, which has made significant equity investments in us since our formation. Upon completion of this offering, Quantum will own approximately 64.8% of our common stock. Please see "Principal and Selling Stockholders".

Quantum Energy Partners is a Houston-based private investment firm founded in 1998. Focused exclusively on the energy sector, Quantum Energy Partners has built one of the leading energy private equity franchises and has managed more than $11 billion of equity commitments since its inception. Quantum Energy Partners has invested in and built over 70 companies in the upstream, midstream, oil field service and power sectors, both domestically and globally.

Risk Factors

Investing in our common stock involves risks that include the speculative nature of oil and natural gas development and production, competition, volatile oil, natural gas and NGL prices and other material factors. You should read carefully the section of this prospectus entitled "Risk Factors" for an explanation of these risks before investing in our common stock. In particular, the following considerations may offset our competitive strengths or have a negative effect on our strategy or operating activities, which could cause a decrease in the price of our common stock and a loss of all or part of your investment:

- Oil, natural gas and NGL prices are volatile. A further reduction or sustained decline in oil, natural gas and NGL prices could adversely affect our business, financial condition and results of operations and our ability to meet our capital expenditure obligations and financial commitments.
- Our acquisition and development projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, which could lead to a decline in our ability to access or grow production and reserves.
- Part of our strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.
- Drilling for and producing oil and natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.
- Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill such locations.
- Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.
- Unless we replace our reserves with new reserves and develop those reserves, our reserves and production will decline, which would adversely affect our future cash flows and results of operations.
- We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under applicable debt instruments, which may not be successful.
- Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage, the primary term is extended through continuous drilling provisions or the leases are renewed.
- Our producing properties are located in the Delaware Basin, a sub-basin of the Permian Basin, in West Texas, making us vulnerable to risks associated with operating in a single geographic area.
- We are dependent on third party pipeline and trucking systems to transport our production and gathering and processing systems to prepare our production. The lack of available capacity in these systems could interfere with our ability to market the oil and natural gas we produce, and could materially and adversely affect our cash flow and results of operations.

- The development of our estimated proved undeveloped reserves ("PUDs") may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated PUDs may not be ultimately developed or produced.
- If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value, we may be required to take write-downs of the carrying values of our properties.
- We depend upon several significant purchasers for the sale of most of our oil, natural gas and NGL production.
- Our operations may be exposed to significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to our business activities.
- We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.
- Climate change laws and regulations restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil and natural gas that we produce, while potential physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.
- Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect our production.
- The requirements of being a public company, including compliance with the reporting requirements of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase our costs and distract management, and we may be unable to comply with these requirements in a timely or cost-effective manner.
- Quantum will have the ability to direct the voting of a majority of our common stock, and its interests may conflict with those of our other stockholders.
- We expect to be a "controlled company" within the meaning of the rules of the New York Stock Exchange (the "NYSE") and, as a result, will qualify for and intend to rely on exemptions from certain corporate governance requirements.

Emerging Growth Company

We are an "emerging growth company" as such term is used in the Jumpstart Our Business Startups Act of 2012 (the "JOBS Act"). For as long as we are an emerging growth company, unlike public companies that are not emerging growth companies under the JOBS Act, we will not be 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(b) of the Sarbanes-Oxley Act of 2002;
- provide more than two years of audited financial statements and related management's discussion and analysis of financial condition and results of operations;

- comply with any new requirements adopted by the Public Company Accounting Oversight Board (the "PCAOB") requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer;
- provide certain disclosure regarding executive compensation required of larger public companies or hold stockholder advisory votes on executive compensation required by the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"); or
- obtain stockholder approval of any golden parachute payments not previously approved.

We will cease to be an emerging growth company upon the earliest of:

- the last day of the fiscal year in which we have $1.0 billion or more in annual revenues;
- the date on which we become a "large accelerated filer" (the fiscal year-end on which the total market value of our common equity securities held by non-affiliates is $700 million or more as of June 30);
- the date on which we issue more than $1.0 billion of non-convertible debt over a three-year period; or
- the last day of the fiscal year following the fifth anniversary of our initial public offering.

In addition, Section 107 of the JOBS Act provides that an emerging growth company can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act of 1933, as amended (the "Securities Act"), for complying with new or revised accounting standards, but we hereby irrevocably opt out of the extended transition period and, as a result, we will adopt new or revised accounting standards on the relevant dates in which adoption of such standards is required for other public companies.

Principal Executive Offices and Internet Address

Our principal executive offices are located at 1125 17th Street, Suite 2400, Denver, Colorado 80202, and our telephone number at that address is (720) 215-3700.

Our website address is *www.jaggedpeakenergy.com*. We expect to make our periodic reports and other information filed with or furnished to the Securities and Exchange Commission (the "SEC"), available free of charge through our website as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference into, and does not constitute a part of, this prospectus.

The Offering

Issuer	Jagged Peak Energy Inc.
Common stock offered by us	26,470,588 shares.
Common stock offered by the selling stockholders	11,754,412 shares (or 17,488,162 shares, if the underwriters exercise in full their option to purchase additional shares).
Common stock outstanding after this offering	211,075,000 shares.
Common stock owned by the selling stockholders after this offering	148,782,032 shares (or 143,048,282 shares if the underwriters exercise in full their option to purchase additional shares).
Option to purchase additional shares	Quantum has granted the underwriters a 30-day option to purchase up to 5,733,750 additional shares of our common stock to the extent the underwriters sell more than 38,225,000 shares of common stock in this offering.
Use of proceeds	We expect to receive approximately $420.8 million of net proceeds (assuming the midpoint of the price range set forth on the cover of this prospectus) from the sale of the common stock offered by us, after deducting underwriting discounts and commissions and estimated offering expenses payable by us. We will not receive any proceeds from the sale of shares by the selling stockholders. We intend to use a portion of the net proceeds we receive from this offering to fully repay the outstanding indebtedness under our credit facility and the remaining net proceeds to fund our 2017 capital program. As of December 31, 2016, we had $132.0 million of outstanding borrowings under our credit facility. Please read "Use of Proceeds".
Conflicts of Interest	Because an affiliate of Wells Fargo Securities, LLC is a lender under our existing credit facility and will receive 5% or more of the net proceeds of this offering due to the repayment of borrowings thereunder, Wells Fargo Securities, LLC is deemed to have a conflict of interest within the meaning of Rule 5121 of the Financial Industry Regulatory Authority, Inc. ("FINRA"). Accordingly, this offering will be conducted in accordance with Rule 5121, which requires, among other things, that a "qualified independent underwriter" participate in the preparation of, and exercise the usual standards of "due diligence" with respect to, the registration statement and this prospectus. Citigroup Global Markets Inc. has agreed to act as a qualified independent underwriter for this offering and to undertake the legal responsibilities and liabilities of an underwriter under the Securities Act, including specifically those inherent in Section 11 thereof. Citigroup Global Markets Inc. will not receive any additional fees for serving as a qualified independent underwriter in connection with this offering. We have agreed to indemnify Citigroup Global Markets Inc. against liabilities incurred in connection with acting as a qualified independent underwriter, including liabilities under the Securities Act. See "Underwriting (Conflicts of Interest)—Conflicts of Interest".

Dividend policy	We do not anticipate paying any cash dividends on our common stock. In addition, our credit agreement places certain restrictions on our ability to pay cash dividends. Please read "Dividend Policy".
Directed share program	The underwriters have reserved for sale at the initial public offering price up to 5% of the common stock being offered by this prospectus for sale to our employees, executive officers, directors, director nominees, business associates and related persons who have expressed an interest in purchasing common stock in this offering. We do not know if these persons will choose to purchase all or any portion of these reserved shares, but any purchases they do make will reduce the number of shares available to the general public. Please read "Underwriting (Conflicts of Interest)".
Listing and trading symbol	We have been authorized to list our common stock on the NYSE under the symbol "JAG".
Risk factors	You should carefully read and consider the information set forth under the heading "Risk Factors" and all other information set forth in this prospectus before deciding to invest in our common stock.

The information above does not include 21,200,000 shares of common stock reserved for issuance pursuant to our 2017 Long-Term Incentive Plan.

Summary Historical Financial Data

The following table shows the summary historical consolidated financial data for the periods and as of the dates indicated, of Jagged Peak Energy LLC, our accounting predecessor. The summary historical interim consolidated financial data of our predecessor as of September 30, 2016, and for the nine months ended September 30, 2016 and 2015, were derived from the unaudited interim consolidated financial statements of our predecessor included elsewhere in this prospectus. The summary historical consolidated financial data of our predecessor as of and for the years ended December 31, 2015 and 2014, were derived from the audited historical consolidated financial statements of our predecessor included elsewhere in this prospectus.

Our historical results are not necessarily indicative of future results. You should read the following table in conjunction with "Use of Proceeds", "Capitalization", "Management's Discussion and Analysis of Financial Condition and Results of Operations" and the historical consolidated financial statements of our predecessor and accompanying notes included elsewhere in this prospectus.

	Nine Months Ended September 30,		Year Ended December 31,	
	2016	2015	2015	2014
	(unaudited)			
	(in thousands, except per share data)			
Statement of Operations Data:				
Revenues:				
Oil sales	$ 47,215	$ 21,445	$ 31,534	$ 14,605
Natural gas sales	1,450	690	948	646
NGL sales	2,023	848	1,329	1,029
Other operating revenues	693	10	—	—
Total revenues	51,381	22,993	33,811	16,280
Operating expenses:				
Lease operating expenses	5,221	2,357	3,165	2,041
Gathering and transportation expenses	662	98	171	121
Production and ad valorem taxes	3,173	1,588	2,244	920
Depletion, depreciation, amortization and accretion	29,430	14,488	22,685	8,444
Impairment of oil and natural gas properties and dry hole costs	1,509	7	6,489	1,414
Other operating expenses	1,671	257	261	64
General and administrative	7,878	5,906	7,446	7,330
Total operating expenses	49,544	24,701	42,461	20,334
Income (loss) from operations	1,837	(1,708)	(8,650)	(4,054)
Other income (expense):				
(Loss) gain on commodity derivatives	(8,208)	1,086	1,323	5,375
Interest expense and other	(1,471)	(77)	(197)	—
Other income	—	—	40	—
Total other (expense) income	(9,679)	1,009	1,166	5,375
Net (loss) income	$ (7,842)	$ (699)	$ (7,484)	$ 1,321
Pro Forma Per-Share Data (unaudited)(1):				
Net loss per common share:				
Basic and diluted	$ (0.02)		$ (0.02)	
Weighted average common shares outstanding:				
Basic and diluted	211,075		211,075	
Balance Sheet Data (at period end):				
Cash and cash equivalents	$ 5,420	$ 12,662	$ 14,165	$ 33,628
Total assets	436,636	309,095	327,732	257,084
Total liabilities	128,606	30,981	43,402	16,270
Total members' equity	308,030	278,114	284,330	240,814
Cash Flow Data:				
Net cash provided by operating activities	$ 16,632	$ 11,905	$ 20,372	$ 7,615
Net cash used in investing activities	(125,984)	(80,318)	(110,232)	(187,067)
Net cash provided by financing activities	100,607	47,448	70,397	199,800
Other Financial Data:				
Adjusted EBITDAX(2)	$ 32,899	$ 16,921	$ 26,510	$ 6,631

(1) The net loss per common share and weighted average common shares outstanding reflect the estimated number of shares of common stock we expect to have outstanding upon the completion of our corporate reorganization described under "Corporate Reorganization". The pro forma per-share data also reflects additional pro forma income tax benefit of $2.8 million and $2.7 million for the nine months ended September 30, 2016 and the year ended December 31, 2015, respectively, associated with the income tax effects of the corporate reorganization described under "Corporate Reorganization" and this offering. Jagged Peak Energy Inc. is a Subchapter C corporation ("C-corp") under the Internal Revenue Code of 1986, as amended (the "Code"), and as a result, will be subject to U.S. federal, state and local income taxes. Although our predecessor was subject to franchise tax in the State of Texas, it generally passed through its taxable income to its owners for other income tax purposes and thus was not subject to U.S. federal income taxes or other state or local income taxes.

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

Non-GAAP Financial Measure

Adjusted EBITDAX

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

We define Adjusted EBITDAX as net income before interest expense, net of capitalized interest, depletion, depreciation, amortization and accretion, impairment of oil and natural gas properties and dry hole costs, exploration expenses, income taxes, and gains or losses on derivatives, net, less net cash from derivative settlements. Adjusted EBITDAX is not a measure of net income as determined by United States generally accepted accounting principles ("GAAP").

Management believes Adjusted 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 Adjusted 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. Adjusted EBITDAX 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 operating performance. Certain items excluded from Adjusted 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 historic costs of depletable and depreciable assets and exploration expenses, none of which are components of Adjusted EBITDAX. Our presentation of Adjusted EBITDAX should not be construed as an inference that our results will be unaffected by such items. Our computations of Adjusted EBITDAX may not be comparable to other similarly titled measures of other companies.

The following table presents a reconciliation of Adjusted EBITDAX to net income, our most directly comparable financial measure calculated and presented in accordance with GAAP.

	Nine Months Ended September 30,		Year Ended December 31,	
	2016	2015	2015	2014
	(in thousands)			
Adjusted EBITDAX reconciliation to net income (loss):				
Net income (loss)	$(7,842)	$ (699)	$(7,484)	$ 1,321
Interest expense, net of capitalized interest	1,471	77	197	—
Depletion, depreciation, amortization and accretion	29,430	14,488	22,685	8,444
Impairment of oil and natural gas properties and dry hole costs	1,509	7	6,489	1,414
Exploration expenses(1)	1,282	7	11	64
Income tax expense (benefit)	—	—	—	—
(Gain) loss on commodity derivatives, net, less net cash from derivative settlements(2)	7,049	3,041	4,612	(4,612)
Adjusted EBITDAX	$32,899	$16,921	$26,510	$ 6,631

(1) Primarily includes delay rental costs to maintain leases.

(2) Has the effect of adjusting net income (loss) for changes in the fair value of derivative instruments, which are recognized at the end of each accounting period because we do not designate commodity derivative instruments as cash flow hedges.

Summary Historical Reserve and Operating Data

The following tables present, for the periods and as of the dates indicated, summary data with respect to our estimated net proved reserves and our production and operating data.

The reserve estimates attributable to our properties as of November 30, 2016, presented in the table below are based on a reserve report prepared by Ryder Scott. All of these reserve estimates were prepared in accordance with the SEC's rules regarding reserve reporting that are currently in effect. The following tables also contain summary unaudited information regarding production and sales of oil and natural gas with respect to such properties.

Please read "Management's Discussion and Analysis of Financial Condition and Results of Operations" and "Business—Oil and Natural Gas Data—Proved Reserves" in evaluating the material presented below.

	As of November 30, 2016(1)
Proved Reserves:	
Oil (MBbls)	26,371
Natural gas (MMcf)	15,290
NGLs (MBbls)	3,761
Total proved reserves (MBoe)(2)	32,680
Proved Developed Reserves:	
Oil (MBbls)	10,644
Natural gas (MMcf)	5,953
NGLs (MBbls)	1,338
Total proved developed reserves (MBoe)(2)	12,974
Proved developed reserves as a percentage of total proved reserves	39.7%
Proved Undeveloped Reserves:	
Oil (MBbls)	15,727
Natural gas (MMcf)	9,337
NGLs (MBbls)	2,423
Total proved undeveloped reserves (MBoe)(2)	19,706

(1) Our estimated net proved reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. For oil and NGL volumes, the average West Texas Intermediate posted price of $41.98 per barrel as of November 30, 2016, was adjusted for gravity, quality, local conditions, gathering, transportation fees and distance from market. For natural gas volumes, the average Henry Hub spot price of $2.39 per MMBtu as of November 30, 2016, was similarly adjusted for gravity, quality, local conditions, gathering, transportation fees and distance from market. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $38.62 per barrel of oil, $14.70 per barrel of NGL and $2.18 per Mcf of natural gas as of November 30, 2016.

(2) Totals may not sum or recalculate due to rounding.

	Nine Months Ended September 30, 2016	Year Ended December 31, 2015
Production and Operating Data:		
Production:		
Oil (MBbls)	1,210	718
Natural gas (MMcf)	669	404
NGLs (MBbls)	141	89
Total (MBoe)(1)	1,463	874
Average net daily production (Boe/d)	5,339	2,395
Average sales price:		
Oil (per Bbl) (before impact of cash-settled derivatives)	$39.02	$43.92
Oil (per Bbl) (after impact of cash-settled derivatives)	38.06	52.19
Natural gas (per Mcf)	2.17	2.35
NGLs (per Bbl)	14.35	14.93
Total (per Boe) (before impact of cash-settled derivatives)	34.65	38.69
Total (per Boe) (after impact of cash-settled derivatives)	33.85	45.48
Operating expenses per Boe:		
Lease operating expenses	$ 3.57	$ 3.62
Gathering and transportation expenses	0.45	0.20
Production and ad valorem taxes	2.17	2.57
Depletion, depreciation, amortization and accretion	20.12	25.94
Impairment of oil and natural gas properties and dry hole costs	1.03	7.42
Other operating expenses	1.14	0.30
General and administrative(2)	5.38	8.52
Total operating expenses per Boe	$33.86	$48.57

(1) Totals may not sum or recalculate due to rounding.

(2) General and administrative does not include additional expenses we would have incurred as a result of being a public company.

RISK FACTORS

Investing in our common stock involves risks. You should carefully consider all of the information in this prospectus, including the matters addressed under "Cautionary Statement Regarding Forward-Looking Statements", and the following risks before making an investment decision. Our business, financial condition and results of operations could be materially and adversely affected by, and the trading price of our common stock could decline, due to any of these risks, and you may lose all or part of your investment. The risks described below are not the only ones facing us. Additional risks not presently known to us or which we consider immaterial may also adversely affect us.

Risks Related to Our Business

Oil, natural gas and NGL prices are volatile. A further reduction or sustained decline in oil, natural gas and NGL prices could adversely affect our business, financial condition and results of operations and our ability to meet our capital expenditure obligations and financial commitments.

Oil, natural gas and NGLs are commodities, and their prices may fluctuate widely in response to market uncertainty and relatively minor changes in the supply of and demand for oil, natural gas and NGLs. Historically, oil, natural gas and NGL prices have been volatile. For example, during the period from January 1, 2014 through January 13, 2017, the WTI spot price for oil has declined from a high of $107.95 per Bbl on June 20, 2014, to $26.19 per Bbl on February 11, 2016, and the Henry Hub spot price for natural gas has declined from a high of $8.15 per MMBtu on February 10, 2014, to a low of $1.49 per MMBtu on March 4, 2016. Likewise, NGLs, which are made up of ethane, propane, isobutene, normal butane and natural gasoline, all of which have different uses and different pricing characteristics, have suffered significant recent declines in realized prices. The prices we receive for our oil, natural gas and NGL production heavily influence our revenue, profitability, access to capital, future rate of growth and carrying value of our properties. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control, which include the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil, natural gas and NGLs;
- the price and quantity of foreign imports of oil, natural gas and NGLs;
- political and economic conditions in or affecting other producing regions or countries, including the Middle East, Africa, South America and Russia;
- actions of the Organization of the Petroleum Exporting Countries, its members and state-controlled oil companies relating to oil price and production controls;
- the level of global exploration, development and production;
- the level of global inventories;
- prevailing prices on local price indexes in the area in which we operate;
- the proximity, capacity, cost and availability of gathering and transportation facilities;
- localized and global supply and demand fundamentals and transportation availability;
- the cost of exploring for, developing, producing and transporting reserves;
- weather conditions and other natural disasters;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels;

• expectations about future commodity prices; and

• U.S. federal, state and local and non-U.S. governmental regulation and taxes.

In the second half of 2014, oil prices began a rapid and significant decline as the global oil supply began to outpace demand. During 2015 and 2016, the global oil supply continued to outpace demand, resulting in a sustained decline in realized prices for oil production. In general, this imbalance between supply and demand reflects the significant supply growth achieved in the United States as a result of shale drilling and oil production increases by certain other countries, including Russia and Saudi Arabia, as part of an effort to retain market share, combined with only modest demand growth in the United States and less-than-expected demand in other parts of the world, particularly in Europe and China. Although there has been a dramatic decrease in drilling activity in the industry, oil storage levels in the United States remain at historically high levels. Until supply and demand balance and the overhang in storage levels begins to decline, prices will likely remain under pressure. The U.S. dollar has also strengthened relative to other leading currencies, which has caused oil prices to weaken, as they are U.S. dollar-denominated. In addition, the lifting of economic sanctions on Iran has resulted in increasing supplies of oil from Iran, adding further downward pressure to oil prices. NGL prices generally correlate to the price of oil. Also adversely affecting the price for NGLs is the supply of NGLs in the United States, which has continued to grow due to an increase in industry participants targeting projects that produce NGLs in recent years. Prices for domestic natural gas began to decline during the third quarter of 2014 and remained weak throughout 2015 and 2016. The declines in natural gas prices are primarily due to an imbalance between supply and demand across North America. The continued duration and magnitude of these commodity price declines cannot be accurately predicted. Compared to 2014, our average realized oil price before the effects of derivative settlements for 2015 fell 43% to $43.92 per barrel, and our average realized oil price for the nine months ended September 30, 2016, has further decreased to $39.02 per barrel. Similarly, our average realized natural gas price for 2015 dropped 38% to $2.35 per Mcf and our average realized price for NGLs declined 49% to $14.93 per barrel. For the nine months ended September 30, 2016, our average realized price for natural gas was $2.17 per Mcf and our average realized price for NGLs was $14.35 per barrel.

Lower commodity prices may reduce our cash flows and borrowing ability. If we are unable to obtain needed capital or financing on satisfactory terms, our ability to develop future reserves could be adversely affected. Furthermore, using lower prices in estimating proved reserves may result in a reduction in proved reserve volumes due to economic limits. In addition, sustained periods with oil and natural gas prices at levels lower than current West Texas Intermediate or Henry Hub strip prices and the resultant effect such prices may have on our drilling economics and our ability to raise capital may require us to re-evaluate and postpone or eliminate our development drilling, which could result in the reduction of some of our proved undeveloped reserves and related standardized measure. If we are required to curtail our drilling program, we may be unable to continue to hold leases that are scheduled to expire, which may further reduce our reserves. As a result, a substantial or extended decline in commodity prices may materially and adversely affect our future business, financial condition, results of operations, liquidity and ability to finance planned capital expenditures.

Our acquisition and development projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, which could lead to a decline in our ability to access or grow production and reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue making substantial capital expenditures related to our acquisition and development projects. Our 2017 capital budget for drilling, completion and recompletion activities and facilities costs is approximately $580.0 million, excluding potential acquisitions. In addition, our production costs may increase as we continue to use enhanced recovery techniques and other new drilling technologies, which are capital intensive and may not produce oil and natural gas in paying quantities or at all. Further, we regularly evaluate potential acquisition opportunities as an important aspect of our growth strategy, and any such acquisitions we pursue could require substantial capital expenditures. We expect to fund our capital expenditures with cash generated by operations, borrowings under our credit facility and a portion of the proceeds from this offering; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities or the sale of assets. The issuance of additional indebtedness would require that a portion of our cash flow from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flow from operations to fund working capital, capital expenditures and acquisitions. The issuance of additional equity securities would be dilutive to our other stockholders. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, oil, natural gas and NGL prices; actual drilling results; the availability of drilling rigs and other services and equipment; and regulatory, technological and competitive developments. A reduction in commodity prices from current levels may result in a decrease in our actual capital expenditures, which would negatively impact our ability to grow production.

Our cash flow from operations and access to capital are subject to a number of variables, including:

- the prices at which our production is sold;
- our proved reserves;
- the level of hydrocarbons we are able to produce from existing wells;
- our ability to acquire, locate and produce new reserves;
- the levels of our operating expenses; and
- our ability to borrow under our credit facility and our ability to access the capital markets.

If our revenues or the borrowing base under our credit facility decrease as a result of lower oil, natural gas and NGL prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. For a period of 180 days following the date of this prospectus, we will not, subject to certain exceptions, be able to sell any shares of our common stock, whether pursuant to a private or public offering, without the prior written consent of Citigroup Global Markets Inc., Credit Suisse Securities (USA) LLC and J.P. Morgan Securities LLC. See "Underwriting (Conflicts of Interest)" for more information. If cash flow generated by our operations or available borrowings under our credit facility are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our properties, which in turn could lead to a decline in our reserves and production, and could materially and adversely affect our business, financial condition and results of operations.

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 horizontal wells include the following:

- 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
- being able to run tools and other equipment consistently through the horizontal wellbore.

Risks that we face while completing our wells include 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.

In addition, certain of the new techniques we are adopting may cause irregularities or interruptions in production due to offset wells being shut in and the time required to drill and complete multiple wells before any such wells begin producing. If our drilling results are less than anticipated, the return on our investment for a particular project may not be as attractive as we anticipated, we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

Drilling for and producing oil and natural gas 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 development, acquisition and production activities, which 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 develop or purchase prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see "—Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves". In addition, our cost of drilling, completing and operating wells is often uncertain.

Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- delays imposed by or resulting from compliance with regulatory requirements including limitations on wastewater disposal, additional regulation related to seismic activity, discharge of greenhouse gases ("GHGs") and limitations on hydraulic fracturing;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel or in obtaining materials required for our drilling activities, including water for hydraulic fracturing activities;
- equipment failures, accidents or other unexpected operational events;
- lack of available and economic gathering and takeaway capacity, including gathering facilities and interconnecting transmission pipelines;
- adverse weather conditions;
- issues related to compliance with environmental regulations;
- environmental hazards, such as oil and natural gas leaks, oil spills, pipeline and tank ruptures and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- declines in oil and natural gas prices;

- limited availability of financing at acceptable terms;
- title problems; and
- limitations in the market for oil and natural gas.

Furthermore, the results of any 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.

Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill such locations.

Our management team has specifically 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 ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors. Because of these uncertain 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 natural gas or oil from these or any other drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the drilling locations are obtained, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified.

As of September 30, 2016, we had identified 1,265 gross horizontal drilling locations on our acreage based on approximately 880-foot spacing in an offset pattern with five to six wells per 640-acre section, consisting of laterals with an average length of 7,426 feet. As a result of the limitations described above, we may be unable to drill many of our identified locations. In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. See "—Our acquisition and development projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, which could lead to a decline in our ability to access or grow production and reserves". Any drilling activities we are able to conduct on these locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our future business and results of operations. Additionally, if we curtail our drilling program, we may lose a portion of our acreage through lease expirations.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of our reserves. In order to prepare reserve estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable reserves may vary from our estimates. For instance, initial production rates reported by us or other operators may not be indicative of future or long-term production rates, our recovery efficiencies may be worse than expected and production declines may be greater than we estimate and may be more rapid and irregular when compared to initial production rates. In addition, we may adjust reserve estimates to reflect additional production history, results of development activities, current commodity prices and other existing factors. Any significant variance could materially affect the estimated quantities and present value of our reserves.

You should not assume that the present value of future net revenues from our reserves is the current market value of our estimated reserves. We generally base the estimated discounted future net cash flows from reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. If spot prices are below such calculated amounts, using more recent prices in estimating proved reserves may result in a reduction in proved reserve volumes due to economic limits.

Unless we replace our reserves with new reserves and develop those reserves, our reserves and production will decline, which would adversely affect our future cash flows and results of operations.

Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploration and development activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future reserves and production, and therefore our future cash flow and results of operations, 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 sufficient additional reserves to replace our current and future production. 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 would be materially and adversely affected.

We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under applicable debt instruments, which may not be successful.

Our ability to make scheduled payments on or to refinance our indebtedness obligations, including our credit facility, depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness.

If our cash flows and capital resources are insufficient to fund debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance indebtedness. Our ability to restructure or refinance indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict business operations. The terms of existing or future debt instruments may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet debt service and other obligations. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet scheduled debt service obligations.

Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.

Our credit agreement contains a number of significant covenants, including restrictive covenants that may limit our ability to, among other things:

- incur additional indebtedness;
- incur liens;
- make investments;
- make loans to others;
- merge or consolidate with another entity;
- sell assets;
- make certain payments;
- enter into transactions with affiliates;
- hedge interest rates; and
- engage in certain other transactions without the prior consent of the lenders.

In addition, our credit agreement requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. For example, as described in greater detail under "Management's Discussion and Analysis of Financial Condition and Results of Operations—Capital Requirements and Sources of Liquidity—Our Credit Facility", we are required to maintain a ratio of current assets to current liabilities of not less than 1.0 to 1.0. On December 28, 2016, we entered into an amendment to our credit facility to, among other things, conditionally waive a potential default with respect to such ratio as of the end of the fourth quarter of 2016; however, there can be no assurances that we would be able to obtain similar waivers in the future.

Further, under our credit agreement, we are only permitted to hedge up to the greater of 85% of our proved reserves and 75% of our reasonably anticipated production for up to 24 months in the future, and up to the greater of 75% of our proved reserves and 50% of our reasonably anticipated production for 25 to 60 months in the future, provided that no hedges may have a term beyond five years. We are currently required to hedge a minimum of 75% of our projected oil volumes from proved developed producing ("PDP") reserves for each calendar month on a two-year rolling basis; however, we do not anticipate that the amended and restated credit facility we will enter into in connection with this offering will contain similar minimum hedging requirements.

The restrictions in our credit agreement may also limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under our credit agreement impose on us.

A breach of any covenant in our credit agreement would result in a default under the applicable agreement after any applicable grace periods. A default, if not waived, could result in acceleration of the indebtedness outstanding under our credit agreement and in a default with respect to, and an acceleration of, the indebtedness outstanding under other debt agreements. The accelerated indebtedness would become immediately due and payable. If that occurs, we may not be able to make all of the required payments or borrow sufficient funds to refinance such indebtedness. Even if new financing were available at that time, it may not be on terms that are acceptable to us.

Any significant reduction in our borrowing base under our credit facility as a result of the periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations.

Our credit facility limits the amounts we can borrow up to a borrowing base amount, which the lenders, in their sole discretion, determine semiannually on April 1 and October 1. The borrowing base depends on, among other things, projected revenues from, and asset values of, the proved oil and natural gas properties securing our loan. The value of our proved reserves is dependent upon, among other things, the prevailing and expected market prices of the underlying commodities in our estimated reserves. See "—Oil, natural gas and NGL prices are volatile. A further reduction or sustained decline in oil, natural gas and NGL prices could adversely affect our business, financial condition and results of operations and our ability to meet our capital expenditure obligations and financial commitments" and "Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves". The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our credit facility. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments. Our borrowing base was $160.0 million as of December 31, 2016; however, it was increased to $180.0 million in January 2017. We anticipate that the amended and restated credit facility we will enter into in connection with this offering will have an initial borrowing base of $180.0 million. Upon entry into the amended and restated credit facility, we expect that our next scheduled borrowing base redetermination will be on or about April 1, 2017.

In the future, we may not be able to access adequate funding under our credit facility as a result of a decrease in borrowing base due to the issuance of new indebtedness, the outcome of a subsequent borrowing base redetermination or an unwillingness or inability on the part of lending counterparties to meet their funding obligations and the inability of other lenders to provide additional funding to cover the defaulting lender's portion. Declines in commodity prices could result in a determination to lower the borrowing base in the future and, in such a case, we could be required to repay any indebtedness in excess of the redetermined borrowing base. As a result, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out business plans, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

Certain of our undeveloped leasehold acreage is subject to leases that will expire over the next several years unless production is established on units containing the acreage, the primary term is extended through continuous drilling provisions or the leases are renewed.

As of September 30, 2016, approximately 29.6% of our total net acreage was held by production or drilling operations. The leases for our net acreage not held by production will expire at the end of their primary term unless production is established in paying quantities under the units containing these leases, the leases are held beyond their primary terms under continuous drilling provisions of the leases or the leases are renewed. If our leases expire and we are unable to renew the leases, we will lose our right to develop the related properties. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors.

Our derivative activities could result in financial losses or could reduce our earnings.

We enter into derivative instrument contracts for a portion of our oil production. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of any derivative instruments.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counterparty to the derivative instrument defaults on its contractual obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- there are issues with regard to legal enforceability of such instruments.

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices or interest rates change in a manner adverse to us, our cash otherwise available for use in our operations would be reduced which could limit our ability to make future capital expenditures and make payments on our indebtedness, and which could also limit the size of our borrowing base. Future collateral requirements will depend on arrangements with our counterparties, highly volatile oil and natural gas prices and interest rates. In addition, derivative arrangements could limit the benefit we would receive from increases in the prices for oil and natural gas, which could also have a material adverse effect on our financial condition.

Our commodity derivative contracts expose us to risk of financial loss if a counterparty fails to perform under a contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make the counterparty unable to perform under the terms of the contract, and we may not be able to realize the benefit of the 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.

During periods of declining commodity prices, our derivative contract 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 with respect to our commodity derivative contracts.

Adverse weather conditions may negatively affect our operating results and our ability to conduct drilling activities.

Adverse weather conditions may cause, among other things, increases in the costs of, and delays in, drilling or completing new wells, power failures, temporary shut-in of production and difficulties in the transportation of our oil, natural gas and NGLs. Any decreases in production due to poor weather conditions will have an adverse effect on our revenues, which will in turn negatively affect our cash flow from operations.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. Drought conditions have persisted in Texas in past years. These drought conditions have led governmental authorities to restrict the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supplies. If we are unable to obtain water to use in our operations, we may be unable to economically produce oil and natural gas, which could have a material and adverse effect on our financial condition, results of operations and cash flows.

Our producing properties are located in the Delaware Basin, a sub-basin of the Permian Basin, in West Texas, making us vulnerable to risks associated with operating in a single geographic area.

All of our producing properties are geographically concentrated in the Delaware Basin, a sub-basin of the Permian Basin, in West Texas. At November 30, 2016, all of our total estimated proved reserves were attributable to properties located in this area. 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, market limitations, availability of equipment and personnel, water shortages or other drought related conditions or interruption of the processing or transportation of oil, natural gas or NGLs. For example, since our production originates in Midland, Texas, our realizations on sales of our oil production may be affected by the Midland-Cushing price differential, which reflects the difference between the price of crude at Midland, Texas, versus the price of crude at Cushing, Oklahoma, a major hub where production from Midland is often transported via pipeline. The price we currently realize on barrels of oil we sell is reduced by the value of the Midland-Cushing differential, which reached as high as $21 per barrel in August 2014. If the Midland-Cushing differential, or other price differentials pursuant to which our production is subject, were to widen due to oversupply or other factors, our revenue could be negatively impacted.

We are dependent on third party pipeline and trucking systems to transport our production and gathering and processing systems to prepare our production. The lack of available capacity in these systems could interfere with our ability to market the oil and natural gas we produce, and could materially and adversely affect our cash flow and results of operations.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production getting to market. The marketability of our oil and natural gas and production depends in part on the availability, proximity and capacity of gathering, processing, pipeline and trucking systems. The amount of oil and natural gas that can be produced and sold is subject to limitation in certain circumstances, such as a lack of contracted capacity on such systems. As a result, we may be required to shut in wells due to the inadequacy or unavailability of crude oil or natural gas pipelines or gathering system capacity. Any significant curtailment in gathering, processing or pipeline system capacity or lack of availability of transport would interfere with our ability to market the oil and natural gas we produce, and could materially and adversely affect the expected results of our drilling program, as well as our cash flow and results of operations.

The marketability of our production is dependent upon transportation and other facilities, certain of which we do not control. If these facilities experience disruptions, our operations could be interrupted and our revenues reduced.

The marketability of our oil and natural gas production depends in part upon the availability, proximity and capacity of transportation facilities owned by third parties. Insufficient production from our wells to support the construction of pipeline facilities by our purchasers or a significant disruption in the availability of our or third-party transportation facilities or other production facilities could adversely impact our ability to deliver to market or produce our oil and natural gas and thereby cause a significant interruption in our operations. If, in the future, we are unable, for any sustained period, to implement acceptable delivery or transportation arrangements or encounter production related difficulties, we may be required to shut in or curtail production. Any such shut in or curtailment, or an inability to obtain favorable terms for delivery of the oil and natural gas produced from our fields, would materially and adversely affect our financial condition and results of operations.

We may incur losses as a result of title defects in the properties in which we invest.

The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. While we typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

The development of our estimated PUDs may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated PUDs may not be ultimately developed or produced.

As of November 30, 2016, approximately 60% of our total estimated proved reserves were classified as proved undeveloped. Development of these proved undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves, increases in costs to drill and develop such reserves or decreases in commodity prices will reduce the value of our estimated PUDs and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our PUDs as unproved reserves. Further, we may be required to write-down our PUDs if we do not drill those wells within five years after their respective dates of booking.

If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value, we may be required to take 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. We incurred no impairment charges of proved properties during 2015; however, if spot or future commodity prices remain at depressed levels or decline further, we may incur impairments in future periods. On January 13, 2017, the WTI spot price for crude oil was $52.37 per barrel and the Henry Hub spot price for natural gas was $3.42 per MMBtu, representing decreases of 51% and 58%, respectively, from the high of $107.95 per barrel of oil and $8.15 per MMBtu for natural gas during 2014. Likewise, NGLs have suffered significant recent declines in realized prices. Lower commodity prices in the future could result in further impairments of our properties, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

Conservation measures and technological advances could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and natural gas may have a material adverse effect on our business, financial condition, results of operations and cash flows.

We depend upon several significant purchasers for the sale of most of our oil, natural gas and NGL production.

We normally sell our production to a relatively small number of customers, as is customary in our business. For the nine months ended September 30, 2016, two purchasers accounted for more than 10% of our revenue: Trafigura Trading, LLC (47%) and Sunoco Partners Marketing (40%). For the year ended December 31, 2015, two purchasers accounted for more than 10% of our revenue: Sunoco

Partners Marketing (68%) and Shell Trading (21%). For the year ended December 31, 2014, two purchasers accounted for more than 10% of our revenue: Shell Trading (72%) and Plains Marketing, LP (15%). During such periods, no other purchaser accounted for 10% or more of our revenue. The loss of any of these purchasers could materially and adversely affect our revenues.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to our business activities.

Our operations are subject to stringent and complex federal, state and local laws and regulations governing the discharge of materials into the environment, health and safety aspects of our operations or otherwise relating to environmental protection. These laws and regulations may impose numerous obligations applicable to our operations, including the acquisition of a permit or other approval before conducting regulated activities; the restriction of types, quantities and concentration of materials that can be released into the environment; the limitation or prohibition of drilling activities on certain lands lying within wilderness, wetlands and other protected areas; the application of specific health and safety criteria addressing worker protection; and the imposition of substantial liabilities for pollution resulting from our operations. Numerous governmental authorities, such as the U.S. Environmental Protection Agency ("EPA") and analogous state agencies, have the power to enforce compliance with these laws and regulations and the permits issued under them. Such enforcement actions often involve taking difficult and costly compliance measures or corrective actions. Failure to comply with these laws and regulations may result in the assessment of sanctions, including administrative, civil or criminal penalties, natural resource damages, the imposition of investigatory or remedial obligations and the issuance of orders limiting or prohibiting some or all of our operations. In addition, we may experience delays in obtaining, or be unable to obtain, required permits, which may delay or interrupt our operations and limit our growth and revenue.

Certain environmental laws impose strict as well as joint and several liability for costs required to remediate and restore sites where hazardous substances, hydrocarbons or solid wastes have been stored or released. We may be required to remediate contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In connection with certain acquisitions, we could acquire, or be required to provide indemnification against, environmental liabilities that could expose us to material losses. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. Our insurance may not cover all environmental risks and costs or may not provide sufficient coverage if an environmental claim is made against us. Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements our business, prospects, financial condition or results of operations could be materially adversely affected.

We may incur substantial losses and be subject to substantial liability claims as a result of our 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.

Our development 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 releases of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater, air and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- personal injuries and death;
- natural disasters; 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 loss to us as a result of claims for:

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

We may elect not to obtain insurance for any or all of these risks 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. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

Properties that we decide to drill may not yield oil or natural gas in commercially viable quantities.

Properties that we decide to drill that do not yield oil or natural gas in commercially viable quantities will adversely affect our results of operations and financial condition. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of micro-seismic data and other technologies and the study of producing fields in the same area 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 commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects. Further, our drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or lost circulation in formations;
- equipment failure or accidents;
- adverse weather conditions;

- compliance with environmental and other governmental or contractual requirements; and
- increases in the cost of, shortages or delays in the availability of, electricity, supplies, materials, drilling or workover rigs, equipment and services.

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 assets or businesses that complement or expand our current business. However, there is no guarantee we will be able to identify attractive acquisition opportunities. In the event we are able to identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms. Competition for acquisitions may also increase the cost of, or cause us to refrain from, completing acquisitions.

The success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

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

Certain of our properties are subject to land use restrictions, which could limit the manner in which we conduct our business.

Certain of our properties are subject to land use restrictions, including city ordinances, which could limit the manner in which we conduct our business. Such restrictions could affect, among other things, our access to and the permissible uses of our facilities as well as the manner in which we produce oil and natural gas and may restrict or prohibit drilling in general. The costs we incur to comply with such restrictions may be significant in nature, and we may experience delays or curtailment in the pursuit of development activities and perhaps even be precluded from the drilling of wells.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oilfield services could adversely affect our ability to execute our development plans within our budget and on a timely basis.

The demand for drilling rigs, pipe and other equipment and supplies, as well as for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry, can fluctuate significantly, often in correlation with oil and natural gas prices, causing periodic shortages. Our operations are concentrated in areas in which industry had increased rapidly, and as a result, demand for such drilling rigs, equipment and personnel, as well as access to transportation, processing and refining facilities in these areas, had increased, as did the costs for those items. To the extent that commodity prices improve in the future, any delay or inability to secure the personnel, equipment, power, services, resources and facilities access necessary for us to resume or increase our development activities could result in production volumes being below our forecasted volumes. In addition, any such negative effect on production volumes, or significant increases in costs, could have a material adverse effect on our cash flow and profitability. Furthermore, if we are unable to secure a sufficient number of drilling rigs at reasonable costs, we may not be able to drill all of our acreage before our leases expire.

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

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

Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the Domenici-Barton Energy Policy Act of 2005 ("EP Act of 2005"), the Federal Energy Regulatory Commission ("FERC") has civil penalty authority under the Natural Gas Act of 1938 (the "NGA") and the Natural Gas Policy Act ("NGPA") to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation. While our operations have not been regulated by FERC as a natural gas company under the NGA, FERC has adopted regulations that may subject certain of our otherwise non-FERC jurisdictional operations to FERC annual reporting and posting requirements. We also must comply with the anti-market manipulation rules enforced by FERC. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability, as described in "Business—Regulation of the Oil and Natural Gas Industry".

A change in the jurisdictional characterization of some of the natural gas assets we use by federal, state or local regulatory agencies or a change in policy by those agencies could result in increased regulation of the natural gas assets we use, which could cause our revenues to decline and operating expenses to increase.

Section 1(b) of the NGA exempts natural gas gathering facilities from the jurisdiction of FERC. We believe that the natural gas pipelines we use meet the traditional tests FERC has used to determine if a pipeline is a gathering pipeline and are, therefore, not subject to FERC jurisdiction. The distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of substantial ongoing litigation and, over time, FERC policy concerning where to draw the line between activities it regulates and activities excluded from its regulation has changed. The classification and regulation of the gathering facilities we use are subject to change based on future determinations by FERC, the courts or Congress. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements and complaint-based rate regulation. In recent years, FERC has taken a more light-handed approach to regulation of the gathering activities of interstate pipeline transmission companies, which has resulted in a number of such companies transferring gathering facilities to unregulated affiliates. As a result of these activities, natural gas gathering may begin to receive greater regulatory scrutiny at both the state and federal levels.

Climate change laws and regulations restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil and natural gas that we produce, while potential physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

In response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment, the EPA has adopted regulations pursuant to the federal Clean Air Act that, among other things, require preconstruction and operating permits for certain large stationary sources. Facilities required to obtain preconstruction permits for their GHG emissions are also required to meet "best available control technology" standards that are being established by the states or, in some cases, by the EPA on a case-by-case basis. These regulatory requirements could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and natural gas production sources in the United States on an annual basis, which include certain of our operations. Furthermore, in May 2016, the EPA finalized rules that establish new controls for emissions of methane from new, modified or reconstructed sources in the oil and natural gas source category, including production, processing, transmission and storage activities. The rules include first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions. In addition, the rules impose leak detection and repair requirements intended to address methane leaks known as "fugitive emissions" from equipment, such as valves, connectors, open-ended lines, pressure-relief devices, compressors, instruments and meters. The EPA has also announced that it intends to impose methane emission standards for existing sources as well but, to date, has not yet issued a proposal. Compliance with these rules will require enhanced record-keeping practices, the purchase of new equipment, such as optical gas imaging instruments to detect leaks, and increased frequency of maintenance and repair activities to address emissions leakage. The rules will also likely require additional personnel time to support these activities or the engagement of third party contractors to assist with and verify compliance. The federal Bureau of Land Management ("BLM") also finalized similar rules regarding the control of methane emissions in November 2016 that apply to oil and natural gas exploration and development activities on public and tribal lands. The rules seek to minimize venting and flaring of emissions from storage tanks and other equipment, and also impose leak detection and repair requirements. These new and proposed rules could result in increased compliance costs on our operations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant legislative activity at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs. These programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs.

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. Demand for our products may also be adversely affected by conservation plans and efforts undertaken in response to global climate change, including plans developed in connection with the recent Paris climate conference in December 2015, which came into effect in November 2016. Many governments also provide, or may in the future provide, tax advantages and other subsidies to support the use and development of alternative energy technologies. Substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce and lower the value of our reserves.

Finally, increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have a material adverse effect on our operations. At this time, we have not developed a comprehensive plan to address the legal, economic, social or physical impacts of climate change on our operations.

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

Hydraulic fracturing is an important and common practice that is used to stimulate production of oil and/or natural gas from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, proppants and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Hydraulic fracturing is typically regulated by state oil and natural gas commissions, but federal agencies have asserted jurisdiction over certain aspects of the process. The EPA has asserted federal regulatory authority pursuant to the federal Safe Drinking Water Act ("SDWA") over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities using diesel fuels. The EPA has also taken the following actions: issued final regulations under the federal Clean Air Act establishing various performance standards, including standards for the capture of air emissions released during hydraulic fracturing, leak detection and permitting; issued an advanced notice of proposed rulemaking under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing; and, in June 2016, published an effluent limitation guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. In addition, the BLM finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands. The U.S. District Court of Wyoming struck down the final rule, finding that the BLM lacked congressional authority to promulgate the rule. The BLM has appealed this decision, and a final decision remains pending. In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. It is unclear how any additional federal regulation of hydraulic fracturing activities may affect our operations.

Certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources "under some circumstances", noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing under the federal SDWA or other regulatory mechanisms.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. For example, in May 2013, the Railroad Commission of Texas issued a "well integrity rule", which updates the requirements for drilling, putting pipe down and cementing wells. The rule also includes new testing and reporting requirements, such as (i) the requirement to submit cementing reports after well completion or after cessation of drilling, whichever is later, and (ii) the imposition of additional testing on wells less than 1,000 feet below usable groundwater. The well integrity rule took effect in January 2014. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of development activities and perhaps even be precluded from drilling wells.

Legislation or regulatory initiatives intended to address seismic activity could restrict our drilling and production activities, as well as our ability to dispose of produced water gathered from such activities, which could have a material adverse effect on our business.

State and federal regulatory agencies recently have focused on a possible connection between the disposal of wastewater in underground injection wells and the increased occurrence of seismic activity, and regulatory agencies at all levels are continuing to study the possible linkage between oil and natural gas activity and induced seismicity. For example, in 2015, the United States Geological Study identified eight states, including Texas, with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and natural gas extraction. In addition, a number of lawsuits have been filed in other states, most recently in Oklahoma, alleging that disposal well operations have caused damage to neighboring properties or otherwise violated state and federal rules regulating waste disposal. In response to these concerns, regulators in some states are seeking to impose additional requirements, including requirements in the permitting of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, in October 2014, the Railroad Commission of Texas published a new rule governing permitting or re-permitting of disposal wells that would require, among other things, the submission of information on seismic events occurring within a specified radius of the disposal well location, as well as logs, geologic cross sections and structure maps relating to the disposal area in question. If the permittee or an applicant of a disposal well permit fails to demonstrate that the produced water or other fluids are confined to the disposal zone or if scientific data indicates such a disposal well is likely to be or determined to be contributing to seismic activity, then the agency may deny, modify, suspend or terminate the permit application or existing operating permit for that well.

We dispose of large volumes of produced water gathered from our drilling and production operations pursuant to permits issued to us by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such gathering or disposal activities. The adoption and implementation of any new laws or regulations that restrict our ability to use hydraulic fracturing or dispose of produced water gathered from our drilling and production activities by limiting volumes, disposal rates, disposal well locations or otherwise or requiring us to shut down disposal wells, could have a material adverse effect on our business, financial condition and results of operations.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil or natural gas and secure trained personnel.

Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel may increase substantially in the future. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

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

We depend on the services of our senior management and technical personnel. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals. The loss of the services of our senior management or technical personnel could have a material adverse effect on our business, financial condition and results of operations.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of 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 cash flow used for drilling and place us at a competitive disadvantage. For example, as of September 30, 2016, outstanding borrowings subject to variable interest rates were approximately $90.0 million, and a 1.0% increase in interest rates would result in an increase in annual interest expense of approximately $0.9 million, assuming the $90.0 million of debt was outstanding for the full year. 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. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

We may be subject to risks in connection with acquisitions of properties.

The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their applicable differentials;
- operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an "as-is" basis.

Future legislation may result in the elimination of certain U.S. federal income tax deductions currently available with respect to oil and natural gas exploration and development. Additionally, future federal, state or local legislation may impose new or increased taxes or fees on oil and natural gas extraction.

Potential legislation, if enacted into law, could make significant changes to U.S. federal and state income tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain U.S. production activities and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of this legislation or any other similar changes in U.S. federal income tax laws, as well as any similar changes in state law, could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could negatively affect our financial condition and results of operations. Additionally, future legislation could be enacted that increases the taxes or fees imposed on oil and natural gas extraction. Any such legislation could result in increased operating costs and/or reduced consumer demand for petroleum products, which in turn could affect the prices we receive for our oil.

Our use of seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. As a result, our drilling activities may not be successful or economical. In addition, the use of advanced technologies, such as 3-D seismic, requires greater pre-drilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures.

Restrictions on drilling activities intended to protect certain species of wildlife may adversely affect our ability to conduct drilling activities in areas where we operate.

Oil and natural gas operations in our operating areas may be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife. Seasonal restrictions may limit our ability to operate in protected areas and can intensify competition for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages when drilling is allowed. These constraints and the resulting shortages or high costs could delay our operations or materially increase our operating and capital costs. Permanent restrictions imposed to protect endangered species could prohibit drilling in certain areas or require the implementation of expensive mitigation measures. The designation of previously unprotected species in areas where we operate as threatened or endangered could cause us to incur increased costs arising from species protection measures or could result in limitations on our activities that could have a material and adverse impact on our ability to develop and produce our reserves.

Laws regulating the derivatives market could adversely affect our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Act established federal oversight and regulation of the over-the-counter derivatives market and entities, such as us, that participate in that market. Under the Dodd-Frank Act, the Commodity Futures Trading Commission ("CFTC") and the SEC have promulgated rules, and are in the process of promulgating other rules, required to implement the derivatives regulatory provisions of the Dodd-Frank Act. Among the rules currently proposed for adoption by the CFTC are proposed rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. These new position limit rules are not yet final, and the impact of the final position rules on us is uncertain at this time.

The Dodd-Frank Act also made the clearing of swaps over a derivatives clearing organization mandatory and the execution of cleared swaps over a board of trade or swap execution facility mandatory, subject to certain exemptions. The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing. The CFTC has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing. Although we expect to qualify for the exception from mandatory clearing available to commercial end-users of swaps, if we were to have to clear any swap we enter, we might not have the same flexibility we have with the bilateral swaps we now enter and would have to post margin with the derivatives clearing organization for such cleared swaps, which could adversely our ability to execute hedges to reduce risk and protect our cash flow, could adversely affect our liquidity and could reduce cash available to us for capital expenditures.

Certain banking regulators and the CFTC have recently adopted final rules establishing minimum margin requirements for uncleared swaps. Although we expect to qualify for exemptions from such margin requirements available to users of swaps who are non-financial end-users entering into uncleared swaps to hedge their commercial risks with respect to any swaps we enter for such purpose, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. If we do not qualify for an exemption from the margin rules, we could have to post initial and variation margin with the counterparties to our swaps, which could impact our liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect our cash flow.

The full impact of the Dodd-Frank Act's swap regulatory provisions and the related rules of the CFTC and SEC on our business will not be known until all of the rules to be adopted under the Dodd-Frank Act have been adopted and fully implemented and the market for derivatives contracts has adjusted. The Dodd-Frank Act, the existing rules and any new rules could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act's swap regulatory provisions and the related rules, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act's swap regulatory provisions were intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and implementing rules is to lower commodity prices. Any of these consequences could have a material and adverse effect on us and our financial condition.

In addition, the European Union and other non-U.S. jurisdictions have implemented or may implement regulations with respect to the derivatives market. If we enter into swaps with counterparties based in foreign jurisdictions, we may become subject to such regulations, which could have adverse effects on our operations similar to the possible effects on our operations of the Dodd-Frank Act's swap regulatory provisions and the rules of the CFTC, SEC and U.S. banking regulators.

The standardized measure of our estimated reserves is not an accurate estimate of the current fair value of our estimated reserves.

Standardized measure is a reporting convention that provides a common basis for comparing oil and natural gas companies subject to the rules and regulations of the SEC. Standardized measure requires the use of specific pricing as required by the SEC as well as operating and development costs prevailing as of the date of computation. Consequently, it may not reflect the prices ordinarily received or that will be received for oil and natural gas production because of varying market conditions, nor may it reflect the actual costs that will be required to produce or develop the oil and natural gas properties. In addition, our predecessor generally passed through its taxable income to its owners for income tax purposes and was not subject to U.S. federal, state or local income taxes other than franchise tax in the State of Texas. Accordingly, our standardized measure does not provide for U.S. federal, state or local income taxes other than franchise tax in the State of Texas. However, following our corporate reorganization, we will be subject to U.S. federal, state and local income taxes. Accordingly, estimates included herein of future net cash flow may be materially different from the future net cash flows that are ultimately received. Therefore, the standardized measure of our estimated reserves included in this prospectus should not be construed as accurate estimates of the current fair value of our proved reserves.

Our business is difficult to evaluate because we have a limited operating history, and we are susceptible to the potential difficulties associated with rapid growth and expansion.

Jagged Peak Energy LLC was formed in 2013. As a result, there is only limited historical financial and operating information available upon which to base your evaluation of our performance.

In addition, we have grown rapidly over the last several years. Our management believes that our future success depends on our ability to manage the rapid growth that we have experienced and the demands from increased responsibility on management personnel. The following factors could present difficulties:

- increased responsibilities for our executive level personnel;
- increased administrative burden;
- increased capital requirements; and
- increased organizational challenges common to large, expansive operations.

Our operating results could be adversely affected if we do not successfully manage these potential difficulties. The historical financial information incorporated herein is not necessarily indicative of the results that may be realized in the future. In addition, our operating history is limited and the results from our current producing wells are not necessarily indicative of success from our future drilling operations.

We may not be able to keep pace with technological developments in our industry.

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 may be forced by competitive pressures 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 that may in the future allow them to implement new technologies before we can. We may not be able to respond to these competitive pressures or 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, our business, financial condition or results of operations could be materially and adversely affected.

Risks Related to this Offering and Our Common Stock

The requirements of being a public company, including compliance with the reporting requirements of the Exchange Act, and the requirements of the Sarbanes-Oxley Act, may strain our resources, increase our costs and distract management, and we may be unable to comply with these requirements in a timely or cost-effective manner.

As a public company, we will need to comply with new laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act of 2002, related regulations of the SEC and the requirements of the NYSE, with which we are not required to comply as a private company. Complying with these statutes, regulations and requirements will occupy a significant amount of time of our board of directors and management and will significantly increase our costs and expenses. We will need to:

- institute a more comprehensive compliance function;
- comply with rules promulgated by the NYSE;
- continue to prepare and distribute periodic public reports in compliance with our obligations under the federal securities laws;
- establish new internal policies, such as those relating to insider trading; and
- involve and retain to a greater degree outside counsel and accountants in the above activities.

Furthermore, while we generally must comply with Section 404 of the Sarbanes Oxley Act of 2002 for our fiscal year ending December 31, 2017, we are not required to have our independent registered public accounting firm attest to the effectiveness of our internal controls until our first annual report subsequent to our ceasing to be an "emerging growth company" within the meaning of Section 2(a)(19) of the Securities Act. Accordingly, we may not be required to have our independent registered public accounting firm attest to the effectiveness of our internal controls until as late as our annual report for the fiscal year ending December 31, 2022. Once it is required to do so, our independent registered public accounting firm may issue a report that is adverse in the event it is not satisfied with the level at which our controls are documented, designed, operated or reviewed. Compliance with these requirements may strain our resources, increase our costs and distract management, and we may be unable to comply with these requirements in a timely or cost-effective manner.

In addition, we expect that being a public company subject to these rules and regulations may make it more difficult and more expensive for us to obtain director and officer liability insurance and we may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for us to attract and retain qualified individuals to serve on our board of directors or as executive officers. We are currently evaluating these rules, and we cannot predict or estimate the amount of additional costs we may incur or the timing of such costs.

If we fail to develop or maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud. As a result, current and potential stockholders could lose confidence in our financial reporting, which would harm our business and the trading price of our common stock.

Effective internal controls are necessary for us to provide reliable financial reports, prevent fraud and operate successfully as a public company. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results would be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future or that we will be able to comply with our obligations under Section 404 of the Sarbanes Oxley Act of 2002. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results or cause us to fail to meet our reporting obligations. Ineffective internal controls could also cause investors to lose confidence in our reported financial information, which would likely have a negative effect on the trading price of our common stock.

The initial public offering price of our common stock may not be indicative of the market price of our common stock after this offering. In addition, an active, liquid and orderly trading market for our common stock may not develop or be maintained, and our stock price may be volatile.

Prior to this offering, our common stock was not traded on any market. An active, liquid and orderly trading market for our common stock may not develop or be maintained after this offering. Active, liquid and orderly trading markets usually result in less price volatility and more efficiency in carrying out investors' purchase and sale orders. The market price of our common stock could vary significantly as a result of a number of factors, some of which are beyond our control. In the event of a drop in the market price of our common stock, you could lose a substantial part or all of your investment in our common stock. The initial public offering price will be negotiated between us, the selling stockholders and the representatives of the underwriters, based on numerous factors which we discuss in "Underwriting (Conflicts of Interest)", and may not be indicative of the market price of our common stock after this offering. Consequently, you may not be able to sell shares of our common stock at prices equal to or greater than the price paid by you in this offering.

The following factors could affect our stock price:

- our operating and financial performance and drilling locations, including reserve estimates;
- quarterly variations in the rate of growth of our financial indicators, such as net income per share, net income and revenues;
- the public reaction to our press releases, our other public announcements and our filings with the SEC;
- strategic actions by our competitors;
- changes in revenue or earnings estimates, or changes in recommendations or withdrawal of research coverage, by equity research analysts;
- speculation in the press or investment community;
- the failure of research analysts to cover our common stock;
- sales of our common stock by us or the selling stockholders or the perception that such sales may occur;
- changes in accounting principles, policies, guidance, interpretations or standards;
- additions or departures of key management personnel;
- actions by our stockholders;
- general market conditions, including fluctuations in commodity prices;
- domestic and international economic, legal and regulatory factors unrelated to our performance; and
- the realization of any risks described under this "Risk Factors" section.

The stock markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock. Securities class action litigation has often been instituted against companies following periods of volatility in the overall market and in the market price of a company's securities. Such litigation, if instituted against us, could result in very substantial costs, divert our management's attention and resources and harm our business, operating results and financial condition.

Quantum will have the ability to direct the voting of a majority of our common stock, and its interests may conflict with those of our other stockholders.

Upon completion of this offering, Quantum will beneficially own approximately 64.8% of our outstanding common stock (or approximately 62.1% if the underwriters' over-allotment option is exercised in full). As a result, Quantum will be able to control matters requiring stockholder approval, including the election of directors, changes to our organizational documents and significant corporate transactions. This concentration of ownership makes it unlikely that any other holder or group of holders of our common stock will be able to affect the way we are managed or the direction of our business. The interests of Quantum with respect to matters potentially or actually involving or affecting us, such as future acquisitions, financings and other corporate opportunities and attempts to acquire us, may conflict with the interests of our other stockholders. Given this concentrated ownership, Quantum would have to approve any potential acquisition of us. In addition, certain of our directors are currently employees of Quantum. These directors' duties as employees of Quantum may conflict with their duties as our directors, and the resolution of these conflicts may not always be in our or your best interest. Furthermore, in connection with this offering, we will enter into a stockholders' agreement with Quantum, Management Holdco and certain of the Management Members. Among other things, the stockholders' agreement is expected to provide that Management Holdco and the Management Members party thereto will vote all of their shares of common stock in accordance with the direction of Quantum. Further, the stockholders' agreement is expected to provide Quantum with the right to designate a certain number of nominees to our board of directors so long as it and its affiliates collectively beneficially own at least 5% of the outstanding shares of our common stock. See "Certain Relationships and Related Party Transactions—Stockholders' Agreement". The existence of a significant stockholder and the stockholders' agreement may have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management or limiting the ability of our other stockholders to approve transactions that they may deem to be in our best interests. Moreover, Quantum's concentration of stock ownership may also adversely affect the trading price of our common stock to the extent investors perceive a disadvantage in owning stock of a company with a significant stockholder.

Certain of our directors and director nominees have significant duties with, and spend significant time serving, entities that may compete with us in seeking acquisitions and business opportunities and, accordingly, may have conflicts of interest in allocating time or pursuing business opportunities.

Certain of our directors and director nominees, who are and will be responsible for managing the direction of our operations and acquisition activities, hold positions of responsibility with other entities (including affiliates of Quantum) that are in the business of identifying and acquiring oil and natural gas properties. For example, three of our directors, Messrs. Davidson, VanLoh, Jr. and Webster, and two of our director nominees, Messrs. Linn and Verma, serve as Venture Partner, Founder and Chief Executive Officer, Managing Director, Senior Advisor and President, respectively, of Quantum Energy Partners, which is in the business of investing in oil and natural gas companies with independent management teams that also seek to acquire oil and natural gas properties. The existing positions held by these directors and director nominees may give rise to fiduciary or other duties that are in conflict with the duties they owe to us. These directors and director nominees may become aware of business opportunities that may be appropriate for presentation to us as well as to the other entities with which they are or may become affiliated. Due to these existing and potential future affiliations, they may present potential business opportunities to other entities prior to presenting them to us, which could cause additional conflicts of interest. They may also decide that certain opportunities are more appropriate for other entities with which they are affiliated, and as a result, they may elect not to present those opportunities to us. These conflicts may not be resolved in our favor. For additional discussion of our management's business affiliations and the potential conflicts of interest of which our stockholders should be aware, see "Certain Relationships and Related Party Transactions".

Quantum and its affiliates are not limited in their ability to compete with us, and the corporate opportunity provisions in our amended and restated certificate of incorporation could enable Quantum to benefit from corporate opportunities that might otherwise be available to us.

Our governing documents will provide that Quantum and its affiliates (including portfolio investments of Quantum and its affiliates) are not restricted from owning assets or engaging in businesses that compete directly or indirectly with us. In particular, subject to the limitations of applicable law, our amended and restated certificate of incorporation will, among other things:

- permit Quantum and its affiliates and our non-employee directors to conduct business that competes with us and to make investments in any kind of property in which we may make investments; and
- provide that if Quantum or any of its affiliates who is also one of our non-employee directors becomes aware of a potential business opportunity, transaction or other matter, they will have no duty to communicate or offer that opportunity to us.

Quantum or its affiliates may become aware, from time to time, of certain business opportunities (such as acquisition opportunities) and may direct such opportunities to other businesses in which they have invested, in which case we may not become aware of or otherwise have the ability to pursue such opportunity. Further, such businesses may choose to compete with us for these opportunities, possibly causing these opportunities to not be available to us or causing them to be more expensive for us to pursue. In addition, Quantum and its affiliates may dispose of oil and natural gas properties or other assets in the future, without any obligation to offer us the opportunity to purchase any of those assets. As a result, our renouncing our interest and expectancy in any business opportunity that may be from time to time presented to Quantum and its affiliates could adversely impact our business or prospects if attractive business opportunities are procured by such parties for their own benefit rather than for ours.

Quantum and its affiliates are established participants in the oil and natural gas industry and have resources greater than ours, which may make it more difficult for us to compete with such persons with respect to commercial activities as well as for potential acquisitions. We cannot assure you that any conflicts that may arise between us and our stockholders, on the one hand, and Quantum, on the other hand, will be resolved in our favor. As a result, competition from Quantum and its affiliates could adversely impact our results of operations.

Our amended and restated certificate of incorporation and amended and restated bylaws, as well as Delaware law, will contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Our amended and restated certificate of incorporation will authorize our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our amended and restated certificate of incorporation and amended and restated bylaws could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- limitations on the removal of directors;
- our classified board of directors, under which a director only comes up for election once every three years;
- limitations on the ability of our stockholders to call special meetings;
- establishing advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders;
- providing that the board of directors is expressly authorized to adopt, or to alter or repeal our amended and restated bylaws; and
- establishing advance notice and certain information requirements for nominations for election to our board of directors or for proposing matters that can be acted upon by stockholders at stockholder meetings.

Our amended and restated certificate of incorporation will designate the Court of Chancery of the State of Delaware as the sole and exclusive forum for certain types of actions and proceedings that may be initiated by our stockholders, which could limit our stockholders' ability to obtain a favorable judicial forum for disputes with us or our directors, officers, employees or agents.

Our amended and restated certificate of incorporation will provide that, unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware will, to the fullest extent permitted by applicable law, be the sole and exclusive forum for (i) any derivative action or proceeding brought on our behalf, (ii) any action asserting a claim of breach of a fiduciary duty owed by any of our directors, officers, employees or agents to us or our stockholders, (iii) any action asserting a claim arising pursuant to any provision of the Delaware General Corporation Law (the "DGCL"), our amended and restated certificate of incorporation or our amended and restated bylaws or (iv) any action asserting a claim against us that is governed by the internal affairs doctrine. Any person or entity purchasing or otherwise acquiring any interest in shares of our capital stock will be deemed to have notice of, and consented to, the provisions of our amended and restated certificate of incorporation described in the preceding sentence. This choice of forum provision may limit a stockholder's ability to bring a claim in a judicial forum that it finds favorable for disputes with us or our directors, officers, employees or agents, which may discourage such lawsuits against us and such persons. Alternatively, if a court were to find these provisions of our amended and restated certificate of incorporation inapplicable to, or unenforceable in respect of, one or more of the specified types of actions or proceedings, we may incur additional costs associated with resolving such matters in other jurisdictions, which could adversely affect our business, financial condition or results of operations.

Investors in this offering will experience immediate and substantial dilution of $15.62 per share.

Based on an assumed initial public offering price of $17.00 per share (the midpoint of the range set forth on the cover of this prospectus), purchasers of our common stock in this offering will experience an immediate and substantial dilution of $15.62 per share in the as-adjusted net tangible book value per share of common stock from the initial public offering price, and our as-adjusted net tangible book value as of September 30, 2016, after giving effect to this offering would be $1.38 per share. This dilution is due in large part to earlier investors having paid substantially less than the initial public offering price when they purchased their shares. See "Dilution".

We do not intend to pay cash dividends on our common stock, and our credit agreement places certain restrictions on our ability to do so. Consequently, your only opportunity to achieve a return on your investment is if the price of our common stock appreciates.

We do not plan to declare cash dividends on shares of our common stock in the foreseeable future. Additionally, our credit agreement places certain restrictions on our ability to pay cash dividends. Consequently, your only opportunity to achieve a return on your investment in us will be if you sell your common stock at a price greater than you paid for it. There is no guarantee that the price of our common stock that will prevail in the market will ever exceed the price that you pay in this offering.

Future sales of our common stock in the public market, or the perception that such sales may occur, could reduce our stock price, and any additional capital raised by us through the sale of equity or convertible securities may dilute your ownership in us.

We may sell additional shares of common stock in subsequent public offerings. We may also issue additional shares of common stock or securities convertible into shares of our common stock. After the completion of this offering, we will have 211,075,000 outstanding shares of common stock. This number includes 38,225,000 shares that we and the selling stockholders are selling in this offering and 5,733,750 shares that Quantum may sell in this offering if the underwriters' over-allotment option is fully exercised, which may be resold immediately in the public market. Following the completion of this offering, and assuming full exercise of the underwriters' over-allotment option, Quantum will own 131,103,219 shares of our common stock, or approximately 62.1% of our total outstanding shares, all of which are restricted from immediate resale under the federal securities laws and are subject to the lock-up agreements between them and the underwriters described in "Underwriting (Conflicts of Interest)", but may be sold into the market in the future. Quantum will be party to a registration rights agreement, which will require us to effect the registration of its shares in certain circumstances no earlier than the expiration of the lock-up period contained in the underwriting agreement entered into in connection with this offering.

In connection with this offering, we intend to file a registration statement with the SEC on Form S-8 providing for the registration of 21,200,000 shares of our common stock issued or reserved for issuance under our 2017 Long-Term Incentive Plan and 10,419,904 shares of our common stock held by Management Holdco with respect to unvested or unallocated awards. Subject to the satisfaction of vesting conditions, the expiration of lock-up agreements and the requirements of Rule 144, shares registered under the registration statement on Form S-8 may be made available for resale immediately in the public market without restriction.

We cannot predict the size of future issuances of our common stock or securities convertible into common stock or the effect, if any, that future issuances and sales of shares of our common stock will have on the market price of our common stock. Sales of substantial amounts of our common stock (including shares issued in connection with an acquisition), or the perception that such sales could occur, may adversely affect prevailing market prices of our common stock.

The underwriters of this offering may waive or release parties to the lock-up agreements entered into in connection with this offering, which could adversely affect the price of our common stock.

We, all of our directors, director nominees and executive officers and the selling stockholders will enter into lock-up agreements pursuant to which we and they will be subject to certain restrictions with respect to the sale or other disposition of our common stock for a period of 180 days following the date of this prospectus. Citigroup Global Markets Inc., Credit Suisse Securities (USA) LLC and J.P. Morgan Securities LLC, at any time and, except in the case of directors, director nominees and executive officers, without notice, may release all or any portion of the common stock subject to the foregoing lock-up agreements. See "Underwriting (Conflicts of Interest)" for more information on these agreements. If the restrictions under the lock-up agreements are waived, then the common stock, subject to compliance with the Securities Act or exceptions therefrom, will be available for sale into the public markets, which could cause the market price of our common stock to decline and impair our ability to raise capital.

We may issue preferred stock the terms of which could adversely affect the voting power or value of our common stock.

Our amended and restated certificate of incorporation will authorize us to issue, without the approval of our stockholders, one or more classes or series of preferred stock having such designations, preferences, limitations and relative rights, including preferences over our common stock respecting dividends and distributions, as our board of directors may determine. The terms of one or more classes or series of preferred stock could adversely impact the voting power or value of our common stock. For example, we might grant holders of preferred stock the right to elect some number of our directors in all events or on the happening of specified events or the right to veto specified transactions. Similarly, the repurchase or redemption rights or liquidation preferences we might assign to holders of preferred stock could affect the residual value of the common stock.

We expect to be a "controlled company" within the meaning of the NYSE rules and, as a result, will qualify for and intend to rely on exemptions from certain corporate governance requirements.

Upon completion of this offering, Quantum will beneficially control a majority of the combined voting power of all classes of our outstanding voting stock. As a result, we expect to be a controlled company within the meaning of the NYSE corporate governance standards. Under the NYSE rules, a company of which more than 50% of the voting power is held by another person or group of persons acting together is a controlled company and may elect not to comply with certain NYSE corporate governance requirements, including the requirements that:

- a majority of the board of directors consist of independent directors;
- the nominating and governance committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities;
- the compensation committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities; and
- there be an annual performance evaluation of the nominating and governance and compensation committees.

These requirements will not apply to us as long as we remain a controlled company. Following this offering, we intend to utilize some or all of these exemptions. Accordingly, you may not have the same protections afforded to stockholders of companies that are subject to all of the corporate governance requirements of the NYSE. See "Management".

For as long as we are an emerging growth company, we will not be required to comply with certain reporting requirements, including those relating to accounting standards and disclosure about our executive compensation, that apply to other public companies.

In April 2012, President Obama signed into law the JOBS Act. We are classified as an "emerging growth company" under the JOBS Act. For as long as we are an emerging growth company, which may be up to five full fiscal years, unlike other public companies, we will not be required to, among other things: (i) 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(b) of the Sarbanes-Oxley Act; (ii) comply with any new requirements adopted by the PCAOB requiring mandatory audit firm rotation or a supplement to the auditor's report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer; (iii) provide certain disclosure regarding executive compensation required of larger public companies; or (iv) hold nonbinding advisory votes on executive compensation. 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 $700.0 million in market value of our 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. If some investors find our common stock to be less attractive as a result, there may be a less active trading market for our common stock and our stock price may be more volatile.

If securities or industry analysts do not publish research or reports about our business, if they adversely change their recommendations regarding our common stock or if our operating results do not meet their expectations, our stock price could decline.

The trading market for our common stock will be influenced by the research and reports that industry or securities analysts publish about us or our business. If one or more of these analysts cease coverage of our company or fail to publish reports on us regularly, we could lose visibility in the financial markets, which in turn could cause our stock price or trading volume to decline. Moreover, if one or more of the analysts who cover our company downgrades our common stock or if our operating results do not meet their expectations, our stock price could decline.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

The information in this prospectus includes “forward-looking statements”. All statements, other than statements of historical fact included in this prospectus, 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 prospectus, the words “could”, “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 management’s 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” and the other information included in this prospectus.

Forward-looking statements may include statements about:

- our business strategy;
- our reserves;
- our drilling prospects, inventories, projects and programs;
- our ability to replace the reserves we produce through drilling and property acquisitions;
- our financial strategy, liquidity and capital required for our drilling program;
- our realized oil, natural gas and NGL prices;
- the timing and amount of our future production of oil, natural gas and NGLs;
- our future drilling plans;
- our competition and government regulations;
- our ability to obtain permits and governmental approvals;
- our pending legal or environmental matters;
- our marketing of oil, natural gas and NGLs;
- our leasehold or business acquisitions;
- our costs of developing our properties;
- our hedging strategy and results;
- general economic conditions;
- credit markets;
- uncertainty regarding our future operating results; and
- our plans, objectives, expectations and intentions contained in this prospectus 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 development, production, gathering and sale of oil, natural gas and NGLs. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating 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" and elsewhere in this prospectus.

Reserve engineering is a process of estimating underground accumulations of hydrocarbons 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 reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions could impact our strategy and 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 prospectus 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 prospectus 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 prospectus.

USE OF PROCEEDS

We expect to receive approximately $420.8 million of net proceeds (assuming the midpoint of the price range set forth on the cover of this prospectus) from the sale of the common stock offered by us after deducting underwriting discounts and commissions and estimated offering expenses payable by us. We will not receive any proceeds from the sale of shares by the selling stockholders.

We intend to use a portion of the net proceeds we receive from this offering to fully repay the outstanding indebtedness under our credit facility, which was $132.0 million as of December 31, 2016. We intend to fund our $580.0 million 2017 capital program with cash flow from operations, the remaining approximately $288.8 million of net proceeds from this offering and borrowings under our credit facility.

Our credit facility matures on June 19, 2020, and bears interest at a variable rate. At December 31, 2016, the weighted average interest rate on borrowings under our credit facility was 3.99%. We also pay a commitment fee on unused amounts of our credit facility of 0.500%. The outstanding borrowings under our credit facility were incurred to fund a portion of our 2015 and 2016 capital expenditures, as well as general and administrative expenses. We may at any time reborrow amounts repaid under our credit facility, and we expect to do so in the future to fund our capital program. In connection with this offering, we will amend and restate our credit facility to, among other things, extend the maturity date to on or around the fifth anniversary of the consummation of this offering.

An affiliate of one of the underwriters is a lender under our existing credit facility and will receive 5% or more of the net proceeds of this offering due to the repayment of borrowings thereunder. Accordingly, this offering is being made in compliance with FINRA Rule 5121. Please read "Underwriting (Conflicts of Interest)".

A $1.00 increase or decrease in the assumed initial public offering price of $17.00 per share (the midpoint of the price range set forth on the cover page of this prospectus) would cause the net proceeds from this offering, after deducting the underwriting discounts and commissions and estimated offering expenses, received by us to increase or decrease, respectively, by approximately $25.0 million, assuming the number of shares offered by us, as set forth on the cover page of this prospectus, remains the same. If the proceeds increase due to a higher initial public offering price, we would use the additional net proceeds to fund additional future capital expenditures or for general corporate purposes. If the proceeds decrease due to a lower initial public offering price, then we would first reduce by a corresponding amount the net proceeds directed to fund our 2017 capital program and then, if necessary, the net proceeds directed to repay outstanding borrowings under our credit facility.

CAPITALIZATION

The following table sets forth our cash and cash equivalents and capitalization as of September 30, 2016:

- on an actual basis for our predecessor; and
- on an as-adjusted basis to give effect to our corporate reorganization as described under "Corporate Reorganization" and the sale of shares of our common stock in this offering at an assumed initial offering price of $17.00 per share (which is the midpoint of the range set forth on the cover of this prospectus) and the application of the net proceeds we receive from this offering as set forth under "Use of Proceeds".

The information set forth in the "As Adjusted" column of the table below is illustrative only and will be adjusted based on the actual initial public offering price and other final terms of this offering. This table should be read in conjunction with "Use of Proceeds" and the historical financial statements and accompanying notes included elsewhere in this prospectus.

	As of September 30, 2016	
	Predecessor Actual	As Adjusted(1)
	(in thousands, except number of shares and par value)	
Cash and cash equivalents	$ 5,420	$ 336,170
Long-term debt, including current maturities:		
Credit facility(2)	90,000	—
Total long-term debt	$ 90,000	$ —
Equity:		
Members' equity	326,098	—
Preferred stock—$0.01 par value; no shares authorized, issued or outstanding, actual; 50,000,000 shares authorized, no shares issued and outstanding, as adjusted	—	—
Common stock—$0.01 par value; no shares authorized, issued or outstanding, actual; 1,000,000,000 shares authorized, 211,075,000 shares issued and outstanding, as adjusted	—	2,111
Additional paid-in capital	—	744,737
Accumulated deficit(3)	(18,068)	(456,582)
Total equity	$308,030	$ 290,266
Total capitalization	$398,030	$ 290,266

(1) A $1.00 increase (decrease) in the assumed initial public offering price of $17.00 per share, which is the midpoint of the price range set forth on the cover page of this prospectus, would increase (decrease) each of additional paid-in capital, total equity and total capitalization by approximately $25.0 million, assuming that the number of shares offered by us, as set forth on the cover page of this prospectus, remains the same, after deducting the estimated underwriting discounts and commissions payable by us. We may also increase or decrease the number of shares we are offering. An increase (decrease) of one million shares offered by us at an assumed offering price of $17.00 per share, which is the midpoint of the price range set forth on the cover page of this prospectus, would increase (decrease) each of additional paid-in capital, total equity and total capitalization by approximately $16.1 million, after deducting the estimated underwriting discounts and commissions and estimated offering expenses payable by us.

(2) As of December 31, 2016, the borrowing base under our credit facility was $160.0 million; however, it was increased to $180.0 million in January 2017. We anticipate that the amended and restated credit facility we will enter into in connection with this offering will have an initial borrowing base of $180.0 million. As of December 31, 2016, we had $132.0 million of outstanding borrowings under our credit facility with $28.0 million of additional borrowing capacity available. After giving effect to the sale of shares of our common stock in this offering, the application of the anticipated net proceeds therefrom and the amendment and restatement of our credit facility in connection therewith, we expect to have $180.0 million of available borrowing capacity under our credit facility.

(3) In connection with our corporate reorganization, we expect to recognize stock compensation expense of approximately $438.5 million at the time of the offering, based on an assumed initial offering price of $17.00 per share (which is the midpoint of the range set forth on the cover of this prospectus), all of which will be non-cash except for $14.7 million related to the management incentive advance payment made in April 2016. In addition, based on an assumed initial offering price of $17.00 per share (which is the midpoint of the range set forth on the cover of this prospectus), approximately $177.1 million of stock compensation expense will be recognized over the next three years as the vesting conditions of the Management Holdco Units are satisfied.

DILUTION

Purchasers of our common stock in this offering will experience immediate and substantial dilution in the net tangible book value (tangible assets less total liabilities) per share of our common stock for accounting purposes. Our net tangible book value as of September 30, 2016, after giving effect to the transactions described under "Corporate Reorganization", was approximately $308.0 million, or $1.67 per share.

Pro forma net tangible book value per share is determined by dividing our net tangible book value, or total tangible assets less total liabilities, by our shares of common stock that will be outstanding immediately prior to the closing of this offering, including giving effect to our corporate reorganization. Assuming an initial public offering price of $17.00 per share (which is the midpoint of the price range set forth on the cover page of this prospectus), after giving effect to the sale of the shares in this offering and further assuming the receipt of the estimated net proceeds (after deducting estimated underwriting discounts and commissions and estimated offering expenses payable by us), our adjusted pro forma net tangible book value as of September 30, 2016, would have been approximately $290.3 million, or $1.38 per share. This represents an immediate decrease in the net tangible book value of $0.29 per share to our existing stockholders and an immediate dilution to new investors purchasing shares in this offering of $15.62 per share, resulting from the difference between the offering price and the pro forma as-adjusted net tangible book value after this offering. The following table illustrates the per share dilution to new investors purchasing shares in this offering:

Assumed initial public offering price per share		$17.00
Pro forma net tangible book value per share as of September 30, 2016 (after giving effect to our corporate reorganization)	$ 1.67	
Decrease per share attributable to new investors in this offering	(0.29)	
As-adjusted pro forma net tangible book value per share (after giving effect to our corporate reorganization and this offering)		1.38
Dilution in pro forma net tangible book value per share to new investors in this offering		$15.62

A $1.00 increase (decrease) in the assumed initial public offering price of $17.00 per share, which is the midpoint of the price range set forth on the cover page of this prospectus, would increase (decrease) our as-adjusted pro forma net tangible book value per share after the offering by $0.11 and increase (decrease) the dilution to new investors in this offering by $0.11 per share, assuming the number of shares offered by us, as set forth on the cover page of this prospectus, remains the same, after deducting the estimated underwriting discounts and commissions and estimated offering expenses payable by us.

The following table summarizes, on an adjusted pro forma basis as of September 30, 2016, the total number of shares of common stock owned by existing stockholders and to be owned by new investors at $17.00 per share, which is the midpoint of the price range set forth on the cover page of this prospectus, and the total consideration paid and the average price per share paid by our existing stockholders and to be paid by new investors in this offering at $17.00, the midpoint of the price range set forth on the cover page of this prospectus, calculated before deduction of estimated underwriting discounts and commissions.

	Shares Acquired		Total Consideration		Average Price Per Share
	Number	Percent	Amount (in thousands)	Percent	
Existing stockholders(1)	184,604,412	87.5%	$326,098	42.0%	$ 1.77
New investors in this offering(2)	26,470,588	12.5	450,000	58.0	17.00
Total	211,075,000	100.0%	$776,098	100.0%	$ 3.68

(1) The number of shares disclosed for the existing stockholders includes 11,754,412 shares being sold by the selling stockholders in this offering and 10,419,904 shares held by Management Holdco.

(2) The number of shares disclosed for the new investors does not include 11,754,412 shares being purchased by the new investors from the selling stockholders in this offering.

The data in the table excludes 21,200,000 shares of common stock reserved for issuance under our 2017 Long-Term Incentive Plan. If the underwriters' over-allotment option is exercised in full, the number of shares held by new investors will be increased to 43,958,750, or approximately 20.8% of the total number of shares of common stock.

SELECTED HISTORICAL CONSOLIDATED FINANCIAL DATA

The following table shows the summary historical consolidated financial data, for the periods and as of the dates indicated, of Jagged Peak Energy LLC, our accounting predecessor. The summary historical interim consolidated financial data of our predecessor as of September 30, 2016, and for the nine months ended September 30, 2016 and 2015, were derived from the unaudited interim consolidated financial statements of our predecessor included elsewhere in this prospectus. The summary historical consolidated financial data of our predecessor as of and for the years ended December 31, 2015 and 2014, were derived from the audited historical consolidated financial statements of our predecessor included elsewhere in this prospectus.

Our historical results are not necessarily indicative of future results. You should read the following table in conjunction with "Use of Proceeds", "Capitalization", "Management's Discussion and Analysis of Financial Condition and Results of Operations", the historical consolidated financial statements of our predecessor and accompanying notes included elsewhere in this prospectus.

	Nine Months Ended September 30,		Year Ended December 31,	
	2016	2015	2015	2014
	(unaudited) (in thousands, except per share data)			
Statement of Operations Data:				
Revenues:				
Oil sales	$ 47,215	$ 21,445	$31,534	$14,605
Natural gas sales	1,450	690	948	646
NGL sales	2,023	848	1,329	1,029
Other operating revenues	693	10	—	—
Total revenues	51,381	22,993	33,811	16,280
Operating expenses:				
Lease operating expenses	5,221	2,357	3,165	2,041
Gathering and transportation expenses	662	98	171	121
Production and ad valorem taxes	3,173	1,588	2,244	920
Depletion, depreciation, amortization and accretion	29,430	14,488	22,685	8,444
Impairment of oil and natural gas properties and dry hole costs	1,509	7	6,489	1,414
Other operating expenses	1,671	257	261	64
General and administrative	7,878	5,906	7,446	7,330
Total operating expenses	49,544	24,701	42,461	20,334
Income (loss) from operations	1,837	(1,708)	(8,650)	(4,054)
Other income (expense):				
(Loss) gain on commodity derivatives	(8,208)	1,086	1,323	5,375
Interest expense and other	(1,471)	(77)	(197)	—
Other income	—	—	40	—
Total other (expense) income	(9,679)	1,009	1,166	5,375
Net (loss) income	$ (7,842)	$ (699)	$ (7,484)	$ 1,321

	Nine Months Ended September 30,		Year Ended December 31,	
	2016	2015	2015	2014
Pro Forma Per-Share Data (unaudited)(1):				
Net loss per common share:				
Basic and diluted	$ (0.02)		$ (0.02)	
Weighted average common shares outstanding:				
Basic and diluted	211,075		211,075	
Balance Sheet Data (at period end):				
Cash and cash equivalents	$ 5,420	$ 12,662	$ 14,165	$ 33,628
Total assets	436,636	309,095	327,732	257,084
Total liabilities	128,606	30,981	43,402	16,270
Total members' equity	308,030	278,114	284,330	240,814
Cash Flow Data:				
Net cash provided by operating activities	$ 16,632	$ 11,905	$ 20,372	$ 7,615
Net cash used in investing activities	(125,984)	(80,318)	(110,232)	(187,067)
Net cash provided by financing activities	100,607	47,448	70,397	199,800
Other Financial Data:				
Adjusted EBITDAX(2)	$ 32,899	16,921	$ 26,510	$ 6,631

(1) The net loss per common share and weighted average common shares outstanding reflect the estimated number of shares of common stock we expect to have outstanding upon the completion of our corporate reorganization described under "Corporate Reorganization". The pro forma per-share data also reflects additional pro forma income tax benefit of $2.8 million and $2.7 million for the nine months ended September 30, 2016 and the year ended December 31, 2015, respectively, associated with the income tax effects of the corporate reorganization described under "Corporate Reorganization" and this offering. Jagged Peak Energy Inc. is a C-corp under the Code, and as a result, will be subject to U.S. federal, state and local income taxes. Although our predecessor was subject to franchise tax in the State of Texas, it generally passed through its taxable income to its owners for other income tax purposes and thus was not subject to U.S. federal income taxes or other state or local income taxes.

(2) Adjusted EBITDAX is a non-GAAP financial measure. For a definition of Adjusted EBITDAX and a reconciliation of Adjusted EBITDAX to net income, see "Summary—Summary Historical Financial Data—Non-GAAP Financial Measure".

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with the "Selected Historical Consolidated Financial Data" and the historical financial statements and related notes included elsewhere in this prospectus. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, market prices for oil and natural gas, production volumes, estimates of proved reserves, capital expenditures, economic and competitive conditions, regulatory changes and other uncertainties, as well as those factors discussed below and elsewhere in this prospectus, particularly in "Risk Factors" and "Cautionary Statement Regarding Forward-Looking Statements", all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. We do not undertake any obligation to update any forward-looking statements except as otherwise required by applicable law.

Overview

We are a growth-oriented, independent oil and natural gas company focused on the acquisition and development of unconventional oil and associated liquids-rich natural gas reserves in the Southern Delaware Basin, a sub-basin of the Permian Basin of West Texas and one of the most prolific unconventional resource plays in North America. Our acreage is located on large, contiguous blocks in the adjacent counties of Winkler, Ward, Reeves and Pecos, with significant original oil-in-place within multiple stacked hydrocarbon-bearing formations. We are focused on increasing stockholder value by (i) growing production and reserves through the development of our multi-year inventory of 1,265 gross horizontal drilling locations with an average lateral length of 7,426 feet, (ii) expanding and improving the resource potential of our existing acreage position and (iii) growing our acreage position through acquisitions and leasing efforts.

Market Conditions

The oil and natural gas industry is cyclical and commodity prices are highly volatile. In the second half of 2014, oil prices began a rapid and significant decline as the global oil supply began to outpace demand. In general, the imbalance between supply and demand reflects the significant supply growth achieved in the United States as a result of shale drilling and oil production increases by certain other countries, including Russia and Saudi Arabia, as part of an effort to retain market share, combined with only modest demand growth in the United States and less-than-expected demand in other parts of the world, particularly in Europe and China. In addition, the lifting of economic sanctions on Iran has resulted in increasing supplies of oil from Iran, adding further downward pressure to oil prices. Although there has been a dramatic decrease in drilling activity in the industry, oil storage levels in the United States remain at historically high levels. Until supply and demand balance and the overhang in storage levels begins to decline, prices are expected to remain under pressure. The U.S. dollar has also strengthened relative to other leading currencies, which has caused oil prices to weaken, as they are U.S. dollar-denominated. NGL prices generally correlate to the price of oil. Also adversely affecting the price for NGLs is the supply of NGLs in the United States, which has continued to grow due to an increase in industry participants targeting projects that produce NGLs in recent years. Prices for domestic natural gas began to decline during the third quarter of 2014 and have continued to be weak throughout 2015 and 2016. The declines in natural gas prices are primarily due to an imbalance between supply and demand across North America. The duration and magnitude of commodity price declines cannot be accurately predicted.

Our revenue, profitability and future growth are highly dependent on the prices we receive for our oil, natural gas and NGL production. Compared to 2014, our realized oil price for 2015 fell 43% to \$43.92 per barrel, and our realized oil price for the nine months ended September 30, 2016, has further decreased to \$39.02 per barrel. Similarly, our realized natural gas price for 2015 dropped 38% to \$2.35 per Mcf and our realized price for NGLs declined 49% to \$14.93 per barrel. For the nine months ended September 30, 2016, our realized prices for natural gas and NGLs further declined to \$2.17 per Mcf and \$14.35 per barrel, respectively. Lower oil, natural gas and NGL prices not only may decrease our revenues, but also may reduce the amount of oil, natural gas and NGLs that we can produce economically and therefore, potentially lower our oil, natural gas and NGL reserves. Lower commodity prices in the future could result in impairments of our properties and may materially and adversely affect our future business, financial condition, results of operations, operating cash flows, liquidity and ability to finance planned capital expenditures. See "Risk Factors—Risks Related to Our Business—If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value, we may be required to take write-downs of the carrying values of our properties". Lower oil, natural gas and NGL prices may also reduce the borrowing base under our credit agreement, which is determined at the discretion of the lenders and is based on the collateral value of our proved reserves that have been mortgaged to the lenders. See "Risk Factors—Risks Related to Our Business—Any significant reduction in our borrowing base under our credit facility as a result of the periodic borrowing base redeterminations or otherwise may negatively impact our ability to fund our operations".

Alternatively, higher oil and natural gas prices may result in significant non-cash fair value losses being incurred on our derivatives, which could cause us to experience net losses. Further, our capital and operating costs have historically risen during periods of increasing oil, natural gas and NGL prices. These cost increases result from a variety of factors beyond our control, such as increases in the cost of electricity, steel and other raw materials that we and our vendors rely upon; increased demand for labor, services and materials as drilling activity increases; and increased taxes. Such costs may rise faster than increases in our revenue if commodity prices rise, thereby negatively impacting our profitability, cash flow and ability to complete development activities as scheduled and on budget. This impact may be magnified to the extent that our ability to participate in the commodity price increases is limited by our derivative activities. See "Risk Factors—Risks Related to Our Business—We could experience periods of higher costs if commodity prices rise. These increases could reduce our profitability, cash flow and ability to complete development activities as planned".

How We Evaluate Our Operations

We use a variety of financial and operational metrics to assess the performance of our oil and natural gas operations, including:

- realized prices on the sale of oil, natural gas and NGLs, after the effects of our commodity derivative contracts on our oil production;
- production results;
- lease operating expenses; and
- Adjusted EBITDAX.

See "—Sources of Our Revenues", "—Production Results", "—Operating Costs and Expenses" and "—Adjusted EBITDAX" and "Summary—Summary Historical Financial Data—Non-GAAP Financial Measure—Adjusted EBITDAX" for a discussion of these metrics.

Sources of Our Revenues

Our revenues are derived from the sale of our oil and natural gas production, including the sale of NGLs that are extracted from our natural gas during processing. For the nine months ended September 30, 2016, our revenues were derived 93% from oil sales, 3% from natural gas sales and 4% from NGL sales. Our oil, natural gas and NGL revenues do not include the effects of derivatives.

Increases or decreases in our revenue, profitability and future production growth are highly dependent on the commodity prices we receive. Oil, natural gas and NGL prices are market driven and have been historically volatile, and we expect that future prices will continue to fluctuate due to supply and demand factors, seasonality and geopolitical and economic factors. See "—Market Conditions" for information regarding the current commodity price environment. A $1.00 per barrel change in our realized oil price would have resulted in a $1.2 million change in oil revenues for the first nine months of 2016. A $0.10 per Mcf change in our realized natural gas price would have resulted in a $0.07 million change in our natural gas revenues for the first nine months of 2016. A $1.00 per barrel change in NGL prices would have changed revenue by $0.1 million for the first nine months of 2016.

The following table presents our average realized commodity prices, as well as the effects of derivative settlements.

	Nine Months Ended September 30,		Year Ended December 31,	
	2016	2015	2015	2014
Crude Oil (per Bbl):				
Average NYMEX price	$41.53	$51.01	$48.76	$92.91
Realized price, before the effects of derivative settlements	$39.02	$46.72	$43.92	$77.28
Realized price, after the effects of derivative settlements	$38.06	$55.71	$52.19	$81.32
Natural Gas (per Mcf):				
Average NYMEX price	$ 2.35	$ 2.76	$ 2.63	$ 4.26
Realized price	$ 2.17	$ 2.57	$ 2.35	$ 3.76
NGLs (per Bbl):				
Average realized NGL price	$14.35	$14.88	$14.93	$29.40

While quoted NYMEX oil and natural gas prices are generally used as a basis for comparison within our industry, the prices we receive are affected by quality, energy content, location and transportation differentials for these products.

See "—Predecessor Results of Operations" below for an analysis of the impact changes in realized prices had on our revenues.

In addition to sales of oil, natural gas, and NGLs, we derive a minimal portion of our revenues from third party sales of fresh water and water disposal services. These revenues are reflected as other operating revenues in the Condensed Consolidated Statements of Operations.

Production Results

The following table presents historical production volumes for our properties for the nine months ended September 30, 2016 and 2015, and the years ended December 31, 2015 and 2014:

	Nine Months Ended September 30,		Year Ended December 31,	
	2016	2015	2015	2014
Oil (MBbls)	1,210	459	718	189
Natural gas (MMcf)	669	269	404	172
NGLs (MBbls)	141	57	89	35
Total (MBoe)(1)	1,463	561	874	253
Average net daily production (Boe/d)(1)	5,339	2,055	2,395	693

(1) May not sum or recalculate due to rounding.

As reservoir pressures decline, production from a given well or formation decreases. Growth in our future production and reserves will depend on our ability to continue to add proved reserves in excess of our production. Accordingly, we plan to maintain our focus on adding reserves through drilling as well as acquisitions. Our ability to add reserves through drilling projects and acquisitions is dependent on many factors, including our ability to borrow or raise capital, obtain regulatory approvals, procure materials, services and personnel and successfully identify and consummate acquisitions. Please read "Risk Factors—Risks Related to Our Business" for a discussion of these and other risks affecting our proved reserves and production.

Derivative Activity

Pricing for oil and natural gas production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. Due to this volatility, we expect to use commodity derivative instruments, such as collars, swaps and basis swaps to hedge price risk associated with our oil production. These hedging instruments will allow us to reduce, but not eliminate, the potential variability in cash flow from operations due to fluctuations in oil prices. This will provide increased certainty of cash flows for funding our drilling program and debt service requirements. These instruments provide only partial price protection against declines in oil prices and may partially limit our potential gains from future increases in prices. We may seek to hedge price risk associated with our natural gas and NGL production in the future. See "—Quantitative and Qualitative Disclosure About Market Risk—Commodity Price Risk" for information regarding our exposure to market risk, including the effects of changes in commodity prices, and our commodity derivative contracts.

We expect to continue to use commodity derivative instruments to hedge our price risk in the future. Subject to restrictions in our revolving credit agreement, our hedging strategy and future hedging transactions will be determined at our discretion and may be different than what we have done on a historical basis. Under our credit agreement, we are only permitted to hedge up to the greater of 85% of our proved reserves and 75% of our reasonably anticipated production for up to 24 months in the future, and up to the greater of 75% of our proved reserves and 50% of our reasonably anticipated production for 25 to 60 months in the future, provided that no hedges may have a term beyond five years. We are currently required to hedge a minimum of 75% of our projected oil volumes from PDP reserves for each calendar month on a two-year rolling basis; however, we do not anticipate that the amended and restated credit facility we will enter into in connection with this offering will contain similar minimum hedging requirements.

Operating Costs and Expenses

Costs associated with producing oil, natural gas and NGLs are substantial. Some of these costs vary with commodity prices, some trend with the type and volume of production and others are a function of the number of wells we own. As of September 30, 2016, and December 31, 2015, we owned interests in 46 and 39 gross producing wells, respectively.

Lease Operating Expenses. Lease operating expenses ("LOE") are the costs incurred in the operation of producing properties and workover costs. Expenses for utilities, direct labor, water transportation, injection and disposal, materials and supplies comprise the most significant portion of our LOE. Certain items, such as direct labor and materials and supplies, generally remain relatively fixed across broad production volume ranges, but can fluctuate depending on activities performed during a specific period. For instance, repairs to our pumping equipment or surface facilities result in increased LOE in periods during which they are performed. Certain operating cost components are variable and increase or decrease as the level of produced hydrocarbons and water increases or decreases. For example, certain power and water disposal costs vary directly with the amount of hydrocarbons and water we produce.

We monitor our operations to ensure that we are incurring LOE at an acceptable level. For example, we monitor our LOE per Boe to determine if any wells or properties should be shut in, repaired, recompleted or sold. This unit rate also allows us to monitor these costs in certain fields and geographic areas to identify trends and to benchmark against other producers. Although we strive to reduce our LOE, these expenses can increase or decrease on a per unit basis as a result of various factors as we operate our properties or make acquisitions and dispositions of properties. For example, we may increase field level expenditures to optimize our operations, incurring higher expenses in one quarter relative to another, or we may acquire or dispose of properties that have different LOE per Boe. These initiatives would influence our overall operating cost and could cause fluctuations when comparing LOE on a period-to-period basis.

Gathering and Transportation Expenses. Gathering and transportation expenses principally consist of expenditures to prepare and transport production from the wellhead to a specified sales point and natural gas processing costs. These costs will fluctuate with increases or decreases in production volumes, contractual fees and changes in fuel and compression costs.

Production and Ad Valorem Taxes. Production taxes are paid on produced oil and natural gas based on a percentage of revenues from production sold at fixed rates established by federal, state or local taxing authorities. In general, the production taxes we pay correlate to changes in our oil, natural gas and NGL revenues. We are also subject to ad valorem taxes in the counties where our production is located. Ad valorem taxes are generally based on the valuation of our oil and natural gas properties, which also trend with oil and natural gas prices and vary across the different counties in which we operate.

Depletion, Depreciation, Amortization and Accretion. Depletion, depreciation, amortization and accretion ("DD&A") is the systematic expensing of the capitalized costs incurred to acquire and develop oil and natural gas properties. We use the successful efforts method of accounting for oil and natural gas activities and, as such, we capitalize all costs incurred related to the acquisition of oil and natural gas properties and the costs of drilling development wells and successful exploratory wells. Please read "—Critical Accounting Policies and Estimates—Successful Efforts Method of Accounting for Oil and Natural Gas Activities" for further discussion.

Impairment of Oil and Natural Gas Properties and Dry Hole Costs. Impairment of oil and natural gas properties and dry hole costs represent (i) the cost to reduce impaired proved oil and gas properties to their fair value, (ii) the cost of unproved properties that will no longer be held by production or extensions of leases and (iii) the costs of unsuccessful exploratory wells. The financial statements included herein reflect certain impairments described in clauses (ii) and (iii) above. Please read "—Critical Accounting Policies and Estimates—Successful Efforts Method of Accounting for Oil and Natural Gas Activities" and "—Critical Accounting Policies and Estimates—Impairment of Oil and Natural Gas Properties" for further discussion.

Other Operating Expenses. Other operating expenses represent delay rentals for leases on certain unproved properties, payments to landowners for water sourcing and disposal related to third party sales, and other costs associated with our oil and natural gas properties.

General and Administrative. General and administrative ("G&A") consists of 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 Expense. We finance a portion of our working capital requirements and capital expenditures with borrowings under our credit facility. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We reflect interest paid to the lenders under our credit facility in interest expense. Interest expense is reflected net of capitalized interest.

Adjusted EBITDAX

We define Adjusted EBITDAX as net income before interest expense, net of capitalized interest, depletion, depreciation, amortization and accretion, impairment of oil and natural gas properties, exploration expenses, income taxes, and net gains or losses on derivatives less net cash from derivative settlements. Adjusted EBITDAX 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 operating performance. Certain items excluded from Adjusted 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 historic costs of depreciable assets and exploration expenses, none of which are components of Adjusted EBITDAX. Our computations of Adjusted EBITDAX may not be comparable to other similarly titled measures of other companies. For further discussion, please read "Summary—Summary Historical Financial Data—Non-GAAP Financial Measure".

Factors Affecting the Comparability of Our Results of Operations to the Historical Results of Our Predecessor

Our future results of operations may not be comparable to the historical results of operations of our predecessor for the periods presented, primarily for the reasons described below.

Public Company Expenses

Upon completion of this offering, we expect to incur direct, incremental G&A expenses as a result of being a publicly traded company, including, but not limited to, costs associated with hiring new personnel, implementation of compensation programs that are competitive with our public company peer group, annual and quarterly reports to stockholders, tax return preparation, independent auditor fees, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs and independent director compensation. These direct, incremental G&A expenses are not included in our historical results of operations.

Income Taxes

Jagged Peak Energy Inc. is a C-corp under the Code, and as a result, will be subject to U.S. federal, state and local income taxes. Although our predecessor was subject to franchise tax in the state of Texas (at a statutory rate of up to 1.00% of a portion of gross revenues apportioned to Texas), it generally passed through its taxable income to its owners for other income tax purposes and thus was not subject to U.S. federal income taxes or other state or local income taxes. Accordingly, the financial data attributable to our predecessor contains no provision for U.S. federal income taxes or income taxes in any state or locality other than franchise tax in the State of Texas. We estimate that Jagged Peak Energy Inc. will be subject to U.S. federal, state and local taxes at a blended statutory rate of 35.5% of pre-tax earnings. Further, if the corporate reorganization discussed under "Corporate Reorganization" had occurred on September 30, 2016, our predecessor would have recognized a deferred tax liability of approximately $63.7 million, primarily related to the tax basis of its long-lived assets being less than its book basis in those assets.

Corporate Reorganization

The corporate reorganization that will be completed simultaneously with the closing of this offering provides a mechanism by which the shares of our common stock to be allocated amongst the Existing Owners, including the holders of our management incentive units, will be determined. As a result, the satisfaction of all conditions relating to certain management incentive units in Jagged Peak Energy LLC held by the Management Members will be probable. Accordingly, we will recognize a charge for stock compensation expense of approximately $438.5 million related to the estimated fair value of the management incentive units at the closing of this offering, based on an assumed initial offering price of $17.00 per share (which is the midpoint of the range set forth on the cover of this prospectus), all of which will be non-cash except for $14.7 million related to the management incentive advance payment made in April 2016. In addition, based on an assumed initial offering price of $17.00 per share (which is the midpoint of the range set forth on the cover of this prospectus), over the next three years as the vesting conditions of the Management Holdco Units are satisfied we will recognize additional non-cash charges for stock compensation expense of approximately $177.1 million.

Predecessor Results of Operations

Nine Months Ended September 30, 2016, Compared to Nine Months Ended September 30, 2015

Oil and Natural Gas Revenues. The following table provides the components of our revenues for the periods indicated, as well as each period's respective average prices and production volumes:

	Nine Months Ended September 30,			
	2016	2015	Change	% Change
	(unaudited)			
Revenues (in thousands):				
Oil sales	$47,215	$21,445	$25,770	120%
Natural gas sales	1,450	690	760	110%
NGL sales	2,023	848	1,175	139%
Other operating revenues	693	10	683	NM
Total revenues	$51,381	$22,993	$28,388	123%
Average sales price(1):				
Oil (per Bbl)	$ 39.02	$ 46.72	$ (7.70)	(16)%
Natural gas (per Mcf)	$ 2.17	$ 2.57	$ (0.40)	(16)%
NGLs (per Bbl)	$ 14.35	$ 14.88	$ (0.53)	(4)%
Total (per Boe)	$ 34.65	$ 40.97	$ (6.32)	(15)%
Production volumes:				
Oil (MBbls)	1,210	459	751	164%
Natural gas (MMcf)	669	269	400	149%
NGLs (MBbls)	141	57	84	147%
Total (MBoe)(2)	1,463	561	902	161%
Average daily production volume:				
Oil (Bbls/d)	4,416	1,681	2,735	163%
Natural gas (Mcf/d)	2,442	985	1,457	148%
NGLs (Bbls/d)	515	209	306	146%
Total (Boe/d)(2)	5,339	2,055	3,284	160%

NM—Not meaningful

(1) Average prices shown in the table reflect prices before the effects of our realized commodity derivative transactions.

(2) Totals may not sum or recalculate due to rounding.

As reflected in the table above, our total revenue for the first nine months of 2016 was 123%, or $28.4 million, higher than our total revenue for the first nine months of 2015. The increase in total revenue is primarily due to an increase of 161% in our total production, offset in part by a 15% decrease in the average sales price compared to the prior period.

Oil sales for the first nine months of 2016 increased 120% to $47.2 million, from $21.4 million for the nine months ended September 30, 2015. The increase in oil sales between periods is attributable to an increase in oil production volumes of 751 MBbls, or 164%, partially offset by a $7.70 per Bbl, or 16%, decrease in our average realized price for oil.

Natural gas sales for the first nine months of 2016 increased 110% to $1.5 million from $0.7 million for the nine months ended September 30, 2015. The increase in natural gas sales relates to an increase in natural gas production volumes of 400 MMcf, or 149%, partially offset by a 16%, or $0.40 per Mcf, decline in natural gas prices.

NGL sales for the first nine months of 2016 increased 139% to $2.0 million, compared to $0.8 million for nine months ended September 30, 2015. The increase in NGL sales is primarily due to an increase in NGL production of 147%, or 84 MBbls, partially offset by a $0.53 per Bbl, or 4%, decrease in our average realized price for NGLs.

Other operating revenues for the first nine months of 2016 increased to $0.7 million, compared to $0.01 million for the nine months ended September 30, 2015. This increase is due to increased sales of our excess fresh water and water disposal capacity between periods.

Operating Expenses. We present per-Boe information because we use this information to evaluate our performance relative to our peers and to identify and measure trends we believe may require additional analysis.

The following table summarizes our expenses for the periods indicated:

	Nine Months Ended September 30,			
	2016	2015	Change	% Change
	(unaudited)			
Operating expenses (in thousands):				
Lease operating expenses	$ 5,221	$ 2,357	$ 2,864	122%
Gathering and transportation expenses	662	98	564	576%
Production and ad valorem taxes	3,173	1,588	1,585	100%
Depletion, depreciation, amortization and accretion	29,430	14,488	14,942	103%
Impairment of oil and natural gas properties and dry hole costs	1,509	7	1,502	NM
Other operating expenses	1,671	257	1,414	550%
General and administrative	7,878	5,906	1,972	33%
Total operating expenses	$49,544	$24,701	$24,843	101%
Expenses per Boe:				
Lease operating expenses	$ 3.57	$ 4.20	$ (0.63)	(15)%
Gathering and transportation expenses	0.45	0.17	0.28	165%
Production and ad valorem taxes	2.17	2.83	(0.66)	(23)%
Depletion, depreciation, amortization and accretion	20.12	25.83	(5.71)	(22)%
Impairment of oil and natural gas properties and dry hole costs	1.03	0.01	1.02	NM
Other operating expenses	1.14	0.46	0.68	148%
General and administrative	5.38	10.53	(5.15)	(49)%
Total operating expenses per Boe	$ 33.86	$ 44.03	$(10.17)	(23)%

NM—Not meaningful

Lease Operating Expenses. Our LOE varies in conjunction with our level of production, the timing of our workover expenses and variations in industry activity that cause fluctuations in service provider costs. LOE increased 122% to $5.2 million for the nine months ended September 30, 2016 from $2.4 million for the nine months ended September 30, 2015. The increase was primarily related to higher production between periods, which resulted in additional costs for contract labor, chemicals and electricity. In addition, in 2016 we generally increased our repair and maintenance program for our operating wells. While our LOE costs increased overall, our LOE per Boe decreased $0.63 per Boe, or

15%, for the nine months ended September 30, 2016 compared with the same period in 2015. The decrease in LOE per Boe is largely the result of scale benefits associated with higher volumes (a higher percentage of our production was from new wells with higher production and lower operating costs relative to our older wells). Additionally, we have improved our overall operating cost efficiencies, including reduced water disposal costs resulting from the increased use of our internal water disposal infrastructure over higher-priced third-party alternatives.

Gathering and Transportation Expenses. Gathering and transportation expenses largely consist of contractual costs to gather, transport and process our natural gas and NGLs, and generally fluctuate with our production. Gathering and transportation expenses increased $0.6 million for the nine months ended September 30, 2016 compared to the nine months ended September 30, 2015, due to increased production, as well as an increase in our per unit gathering and transportation expense. The period over period increase in our per unit gathering and transportation expense was due to a shift away from marketing our natural gas under percent-of-proceeds contracts toward marketing a larger portion of our natural gas under fixed fee contracts. Under percent-of-proceeds contracts, we receive a percentage of the total proceeds received by the marketer, which is net of transportation expense. Accordingly, we do not book a separate charge for gathering and transportation expense under those contracts. Whereas, under our fixed fee natural gas marketing contracts, we receive a topline revenue amount and are separately charged for the associated gathering and transportation expense.

Production and Ad Valorem Taxes. Production taxes are based on the market value of our production, and ad valorem taxes are primarily based on the valuation of our producing oil and natural gas properties. Production and ad valorem taxes increased 100% to $3.2 million for the nine months ended September 30, 2016 from $1.6 million for the nine months ended September 30, 2015. The increase is primarily due to an increase in revenues and the addition of several new high-volume wells between periods.

Depletion, Depreciation, Amortization and Accretion. Our DD&A expense increased 103% to $29.4 million for the nine months ended September 30, 2016 from $14.5 million for the nine months ended September 30, 2015. The increase in DD&A is largely due to an increase in production, partially offset by a decrease in our DD&A rate. Our DD&A rate can vary due to changes in proved reserve volumes, acquisition and disposition activity, development costs and impairments. The DD&A rate decreased 22% to $20.12 per Boe for the nine months ended September 30, 2016 from $25.83 per Boe for the nine months ended September 30, 2015. The decrease in our DD&A rate was largely due to an increase in reserve volumes due to successful drilling activities, partly offset by an increase in capitalized costs in proved property from these same activities.

Impairment of Oil and Natural Gas Properties and Dry Hole Costs. We incurred $1.5 million of impairment and dry hole costs for the nine months ended September 30, 2016 primarily due to $1.2 million of dry hole costs related to a vertical test well drilled to a shallow horizon we no longer consider prospective. Additionally, we incurred $0.3 million of impairment costs related to the expiration of certain leases on unproved properties. No impairments were recorded on proved properties for the nine month periods ended September 30, 2016 and September 30, 2015.

Other Operating Expenses. We incurred $1.7 million of other operating expenses for the nine months ended September 30, 2016 primarily due to $1.3 million in delay rentals on certain unproved properties, $0.2 million in landowner payments related to third party sales of fresh water and water disposal and $0.2 million due to the termination of a rig contract. We incurred $0.3 million of other operating expenses for the nine months ended September 30, 2015 in conjunction with the termination of a rig contract.

General and Administrative. G&A increased 33% to $7.9 million for the nine months ended September 30, 2016 from $5.9 million for the nine months ended September 30, 2015. The increase was due to a $1.0 million employee separation payment paid in the first quarter of 2016, $0.7 million of additional employee and contractor costs required to manage our expanding capital program and production levels and $0.2 million of additional legal, audit, tax and travel costs during the first nine months of 2016. While our G&A costs increased overall, our G&A per Boe decreased $5.15, or 49%, between periods due primarily to increased production.

Other Income and Expenses. The following table summarizes our other income and expenses for the periods indicated:

	Nine Months Ended September 30,		
	2016	2015	Change
Other (expense) income (in thousands):			
Gain (loss) on commodity derivates	$(8,208)	$1,086	$ (9,294)
Interest expense and other	(1,471)	(77)	(1,394)
Total other income (expense)	$(9,679)	$1,009	$(10,688)

Gain (loss) on Commodity Derivatives. During the nine months ended September 30, 2016, we incurred an $8.2 million net loss on commodity derivatives primarily because the oil forward price curve at September 30, 2016 was generally higher than when we entered into the derivative contracts that were open at September 30, 2016. We also paid $1.2 million in net cash payments to settle derivative contracts during the first nine months of 2016. During the nine months ended September 30, 2015, we recorded a $1.1 million net gain due largely to $4.1 million of net cash receipts from derivative contracts settled during the period, offset by a fair value loss because the forward price curve at September 30, 2015 was generally higher than when we entered into the derivative contracts open at September 30, 2015.

Interest Expense and Other. During the nine months ended September 30, 2016 and 2015, we recorded $1.5 million and $0.07 million, respectively, of interest expense related to the borrowings on our credit facility. We began borrowing on our credit facility in July 2015.

Year Ended December 31, 2015, Compared to the Year Ended December 31, 2014

Oil and Natural Gas Revenues. The following table provides the components of our revenues for the years indicated, as well as each year's respective average prices and production volumes:

	Year Ended December 31,			
	2015	2014	Change	% Change
Revenues (in thousands):				
Oil sales	$31,534	$14,605	$16,929	116%
Natural gas sales	948	646	302	47%
NGL sales	1,329	1,029	300	29%
Total revenues	$33,811	$16,280	$17,571	108%
Average sales price:(1)				
Oil (per Bbl)	$ 43.92	$ 77.28	$(33.36)	(43)%
Natural gas (per Mcf)	2.35	3.76	(1.41)	(38)%
NGLs (per Bbl)	14.93	29.40	(14.47)	(49)%
Total (per Boe)	$ 38.69	$ 64.35	$(25.66)	(40)%
Production:				
Oil (MBbls)	718	189	529	280%
Natural gas (MMcf)	404	172	232	135%
NGLs (MBbls)	89	35	54	154%
Total (MBoe)(2)	874	253	622	246%
Average daily production volumes:				
Oil (Bbls/d)	1,967	518	1,449	280%
Natural gas (Mcf/d)	1,107	471	636	135%
NGLs (Bbls/d)	244	96	148	154%
Total (Boe/d)(2)	2,395	693	1,702	246%

(1) Average prices shown in the table reflect prices before the effects of our realized commodity derivative transactions.

(2) Totals may not sum or recalculate due to rounding.

Our total oil and natural gas revenues for 2015 were 108%, or $17.5 million, higher than in 2014 despite a 40% decrease in commodity prices. The increase in oil and natural gas revenues is due to an increase in production volumes of 622 MBoe, or 246%, as a result of having several additional high-producing wells on production in 2015 as compared to 2014.

Oil sales increased 116%, or $16.9 million, due to a 280% increase in production volumes, partially offset by a 43% decrease in average sales price for 2015 as compared to the prior year. Natural gas sales increased 47%, or $0.3 million, primarily due to a 135% increase in sales volumes from new wells in 2015, partially offset by a 38% decrease in average sales price as compared to the prior year. NGL sales increased 29%, or $0.3 million, primarily due to a 154% increase in sales volumes from new wells in 2015, partially offset by a 49% decrease in average sales price as compared to 2014.

Operating Expenses. The following table summarizes our expenses for the periods indicated:

	Year Ended December 31, 2015	Year Ended December 31, 2014	Change	% Change
Operating expenses (in thousands):				
Lease operating expenses	$ 3,165	$ 2,041	$ 1,124	55%
Gathering and transportation expenses	171	121	50	41%
Production and ad valorem taxes	2,244	920	1,324	144%
Depletion, depreciation, amortization and accretion	22,685	8,444	14,241	169%
Impairment of oil and natural gas properties and dry hole costs	6,489	1,414	5,075	359%
Other operating expenses	261	64	197	308%
General and administrative	7,446	7,330	116	2%
Total operating expenses	$42,461	$20,334	$22,127	109%
Operating expenses per Boe:				
Lease operating expenses	$ 3.62	$ 8.07	$ (4.45)	(55)%
Gathering and transportation expenses	0.20	0.48	(0.28)	(58)%
Production and ad valorem taxes	2.57	3.64	(1.07)	(29)%
Depletion, depreciation, amortization and accretion	25.94	33.38	(7.44)	(22)%
Impairment of oil and natural gas properties and dry hole costs	7.42	5.58	1.84	33%
Other operating expenses	0.30	0.25	0.05	20%
General and administrative	8.52	28.97	(20.45)	(71)%
Total operating expenses per Boe	$ 48.57	$ 80.37	$ (31.80)	(40)%

Lease Operating Expenses. LOE increased 55%, or $1.1 million, in 2015 as compared to 2014, due primarily to higher production between periods, resulting in increased needs for utilities, produced water disposal, repairs and maintenance. While our LOE increased overall, LOE per Boe decreased by $4.45, or 55%, from $8.07 in 2014 to $3.62 in 2015, due primarily to a higher percentage of our production coming from new high-producing, low-operating costs wells. We also improved our overall operating efficiencies, including the continued construction of our water disposal infrastructure.

Gathering and Transportation Expenses. Gathering and transportation expenses increased 41%, or $0.1 million, in 2015 as compared to 2014, primarily due to an increase in production volumes, as well as an increase in the amount of natural gas being sold under sales contracts that provided for certain gathering and transportation costs to be passed through to the producer.

Production and Ad Valorem Taxes. Production and ad valorem taxes increased 144%, or $1.3 million in 2015 as compared to 2014, primarily due to higher production revenue. Production and ad valorem taxes as a percentage of our revenue was 6.6% for 2015 compared to 5.7% for 2014. In addition, ad valorem taxes increased largely because of the addition of several new high-value wells.

Depletion, Depreciation, Amortization and Accretion. Our DD&A expense increased 169%, or $14.2 million, in 2015 as compared to 2014, primarily due to increased production partially offset by a decrease in our DD&A rate. The DD&A rate decreased 22% to $25.94 in 2015 from $33.38 in 2014. The decrease in the DD&A rate was largely due to an increase in reserve volumes due to successful drilling activities, offset by an increase in capitalized costs in proved properties from these same activities.

Impairment of Oil and Natural Gas Properties and Dry Hole Costs. In 2015 and 2014, we recorded $6.5 million and $1.4 million, respectively, of impairment expense related to the expiration of certain leases on unproved properties. Please read "—Overview—Operating Costs and Expenses—Impairment of Oil and Natural Gas Properties and Dry Hole Costs" for further discussion. No impairments were recorded on proved properties during 2015 or 2014.

Other Operating Expenses. We incurred $0.3 million of other operating expenses in 2015 primarily related to the termination of a rig contract. We incurred $0.1 million of other operating expenses in 2014, primarily due to delay rentals on certain unproved properties.

General and Administrative. G&A in 2015 increased 2%, or $0.1 million, as compared to 2014, primarily due to increased employee and contractor costs to manage our growing production and capital program. While our G&A costs increased overall, our G&A per Boe decreased $20.45, or 71%, between periods due primarily to our increasing production.

Other Income and Expenses. The following table summarizes our other income and expenses for the periods indicated:

	Year Ended December 31,			
	2015	**2014**	**Change**	**% Change**
Other income (expense) (in thousands):				
Gain on commodity derivatives	$1,323	$5,375	$(4,052)	(75)%
Interest expense and other	(197)	—	(197)	NM
Other income	40	—	40	NM
Total other income (expense)	$1,166	$5,375	$(4,029)	(78)%

NM—Not meaningful.

Gain on Commodity Derivatives. During 2015, we incurred a $1.3 million net gain primarily related to $5.9 million of cash receipts from derivatives settled during 2015. This gain was partially offset because the forward price curve at the end of the period was generally lower than the forward price curves that were in effect when we entered into the majority of the related derivative contracts. During 2014, we incurred a $5.4 million net gain primarily because the forward price curve at the end of 2014 was generally lower than forward price curves that were in effect when we entered into the majority of the related derivative contracts. In addition, we received cash of approximately $0.8 million related to derivatives settled during 2014.

Interest Expense and Other. We incurred $0.2 million of interest expense in 2015 in conjunction with borrowings under our credit facility.

Capital Requirements and Sources of Liquidity

Our acquisition and development activities require us to make significant operating and capital expenditures. Historically, our primary sources of liquidity have been capital contributions from our equity owners, borrowings under our credit facility and cash flows from operations. To date, our primary use of capital has been for the acquisition and development of oil and natural gas properties.

The amount and allocation of future capital expenditures will depend upon a number of factors, including the number and size of acquisition opportunities, our cash flows from operating, investing and financing activities and our ability to assimilate acquisitions and execute our drilling program. We periodically review our capital expenditure budget to assess changes in current and projected cash flows, acquisition and divestiture activities, debt requirements and other factors. If we are unable to obtain funds when needed or on acceptable terms, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to maintain our production or proved reserves.

We plan to continue our practice of entering into hedging arrangements to reduce the impact of commodity price volatility on our cash flow from operations. Under this strategy, we expect to maintain an active hedging program that seeks to reduce our exposure to commodity price volatility and protect our cash flow, returns and the funding of our capital program while also providing stability to our borrowing base.

Our 2017 capital budget for drilling, completion and recompletion activities and facilities costs is approximately $580.0 million, excluding potential acquisitions. We expect to allocate approximately $527.0 million of our 2017 capital budget for the drilling and completion of operated wells. In the nine months ended September 30, 2016, we incurred capital costs of approximately $86.6 million, excluding leasehold and acquisition costs. In addition, we incurred capital costs of $39.3 million for acquiring undeveloped properties. Based on our 2017 capital budget, we anticipate that we will spud approximately 70 gross wells, including operated and non-operated wells, during 2017.

Because we operate a high percentage of our acreage, capital expenditure amounts and timing are largely discretionary and within our control. We determine our capital expenditures depending on a variety of factors, including, but not limited to, the success of our drilling activities, prevailing and anticipated prices for oil and natural gas, the availability of necessary equipment, infrastructure and capital, the receipt and timing of required regulatory permits and approvals, seasonal conditions, drilling and acquisition costs and the level of participation by other working interest owners. A deferral of planned capital expenditures, particularly with respect to drilling and completing new wells, could result in a reduction in anticipated production and cash flows. Additionally, if we curtail our drilling program, we may lose a portion of our acreage through lease expirations. See "Business—Oil and Natural Gas Production Prices and Costs—Developed and Undeveloped Acreage". In addition, we may be required to reclassify some portion of our reserves currently booked as proved undeveloped reserves to no longer be proved reserves if such a deferral of planned capital expenditures means we will be unable to develop such reserves within five years of their initial booking.

As of December 31, 2016, we had $132.0 million outstanding under our credit facility with $28.0 million of additional borrowing capacity available. We intend to use a portion of the net proceeds from this offering to fully repay the outstanding borrowings under our credit facility. Our borrowing base was $160.0 million as of December 31, 2016; however, it was increased to $180.0 million in January 2017. We anticipate that the amended and restated credit facility we will enter into in connection with this offering will have an initial borrowing base of $180.0 million. Upon entry into the amended and restated credit facility, we expect that our next scheduled borrowing base redetermination will be on or about April 1, 2017.

Based upon our current oil and natural gas price expectations for 2017, following the closing of this offering, we believe that our cash flow from operations, additional borrowings under our credit facility and a portion of the proceeds from this offering will provide us with sufficient liquidity to execute our current capital program through 2017. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and significant additional capital expenditures will be required to more fully develop our properties. If we require additional capital for capital expenditures, acquisitions or other reasons, we may seek such capital through traditional reserve base borrowings, joint venture partnerships, production payment financings, asset sales, offerings of debt and equity securities or other means. If we are unable to obtain funds when needed or on acceptable terms, we may be required to curtail our current drilling program, which could result in a loss of acreage through lease expirations. In addition, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to maintain our production or replace our reserves.

Working Capital

Our working capital, which we define as current assets minus current liabilities, totaled a deficit of $19.8 million at September 30, 2016. At December 31, 2015, we had a working capital surplus of approximately $0.05 million, and at December 31, 2014, we had a working capital surplus of approximately $25.3 million. We may incur additional working capital deficits in the future due to the amounts that accrue related to our drilling program. Our collection of receivables has historically been timely, and losses associated with uncollectible receivables have historically not been significant. Our cash and cash equivalents balance totaled approximately $5.4 million, $14.2 million and $33.6 million at September 30, 2016, December 31, 2015 and December 31, 2014, respectively. We expect that our cash flows from operating activities, availability under our credit facility after application of the estimated net proceeds from this offering as described under "Use of Proceeds" and the remaining portion of the proceeds from this offering will be sufficient to fund our working capital needs through 2017. We expect that our pace of development, production volumes, commodity prices and differentials to NYMEX prices for our oil and natural gas production will be the largest variables affecting our working capital.

Cash Flows

The following table summarizes our cash flows for the periods indicated:

	Nine Months Ended September 30,		Year Ended December 31,	
	2016	2015	2015	2014
	(unaudited)			
	(in thousands)			
Net cash provided by operating activities	$ 16,632	$ 11,905	$ 20,372	$ 7,615
Net cash used in investing activities	$(125,984)	$(80,318)	$(110,232)	$(187,067)
Net cash provided by financing activities	$ 100,607	$ 47,448	$ 70,397	$ 199,800

Analysis of Cash Flow Changes Between the Nine Months Ended September 30, 2016 and 2015

Operating Activities. Net cash provided by operating activities is primarily affected by the price of oil, natural gas and NGLs, production volumes and changes in working capital. The increase in net cash provided by operating activities for the first nine months of 2016 compared to the prior-year period is primarily due to an increase in revenue of $27.7 million and a favorable change in operating assets and liabilities of $6.0 million, partially offset by a $14.7 million non-recurring management incentive advance, a $5.3 million decrease in net cash received for settlements of derivatives, and higher operating costs due to an increase in production.

Investing Activities. Net cash used in investing activities is primarily comprised of acquisition and development of oil and natural gas properties, net of dispositions. The increased amount of cash used in investing activities was primarily due to a $31.0 million increase in leasehold and acquisition costs and a $12.5 million increase in costs to develop oil and natural gas properties for the first nine months of 2016 as compared to the prior-year period.

Financing Activities. Net cash provided by financing activities in the first nine months of 2016 primarily included $70.0 million of borrowings under our credit facility and $31.5 million of proceeds from the issuance of equity interests, partially offset by $1.0 million of debt issuance cost. Net cash provided by financing activities in the first nine months of 2015 primarily included $38.0 million of cash provided by equity issuances and $10.0 million of borrowings under our credit facility, partially offset by $0.6 million of debt issuance cost.

Analysis of Cash Flow Changes Between the Year Ended December 31, 2015 and 2014

Operating Activities. The increase in net cash provided by operating activities for the year ended December 31, 2015 as compared to the prior-year period is primarily due to a $17.5 million increase in total revenues and a $5.2 million increase in net cash received for settlements of derivatives, offset by an $7.0 million decrease in operational assets and liabilities and higher operating costs due to an increase in production.

Investing Activities. In 2015, net cash used for investing activities included $110.5 million for the acquisition and development of oil and natural gas properties, offset by proceeds from asset sales of $0.4 million. In 2014, net cash used for investing activities included $188.9 million for the acquisition and development of oil and natural gas properties and $1.1 million of other property, plant and equipment, offset by proceeds from asset sales of $2.9 million.

Financing Activities. Net cash provided by financing activities in 2015 included $51.0 million of cash provided by equity issuances and $20.0 million of borrowings under our credit facility, offset by debt issuance costs of $0.6 million. Net cash provided by financing activities in 2014 consisted of $199.8 million of cash provided by equity issuances.

Our Credit Facility

On June 19, 2015, we entered into a credit agreement (as amended to date and, unless otherwise indicated, as amended and restated in connection with this offering, our "credit agreement") with Wells Fargo Bank, National Association, as administrative agent and issuing lender, and the lenders named therein, that provides for a senior secured revolving credit facility (our "credit facility") with commitments of $500.0 million (subject to the borrowing base); however, we anticipate that the amended and restated credit facility we will enter into in connection with this offering will provide for commitments of $1.0 billion (subject to the borrowing base). As of December 31, 2016, the borrowing base under our credit facility was $160.0 million; however, it was increased to $180.0 million in January 2017. We anticipate that the amended and restated credit facility we will enter into in connection with this offering will have an initial borrowing base of $180.0 million. Upon entry into the amended and restated credit facility, we expect that our next scheduled borrowing base redetermination will be on or about April 1, 2017. As of December 31, 2016, we had $132.0 million outstanding under our credit facility with $28.0 million of additional borrowing capacity available. We intend to use a portion of the net proceeds of this offering to fully repay the outstanding borrowings under our credit facility. Our credit facility matures on June 19, 2020, which we expect to extend to on or around the fifth anniversary of the consummation of this offering pursuant to the amendment and restatement thereof in connection with this offering.

The amount available to be borrowed under our credit facility is subject to a borrowing base that is redetermined semiannually each April 1 and October 1 by the lenders at their sole discretion. Additionally, at our option, we may request up to two additional redeterminations per year to be effective on or about January 1 and July 1, respectively. The borrowing base depends on, among other things, the volumes of our proved reserves and estimated cash flows from these reserves and our commodity hedge positions as well as any other outstanding debt. Upon a redetermination of the borrowing base, if borrowings in excess of the revised borrowing capacity are outstanding, we could be required to immediately repay a portion of the debt outstanding under our credit agreement.

At December 31, 2016, the weighted average interest rate on borrowings under our credit facility was approximately 3.99%. We also pay a commitment fee on unused amounts of our credit facility of 0.500%. We may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs.

Our credit agreement contains restrictive covenants that limit our ability to, among other things:

- incur additional indebtedness;
- incur liens;
- make investments;
- make loans to others;
- merge or consolidate with another entity;
- sell assets;
- make certain payments;
- enter into transactions with affiliates;
- hedge interest rates; and
- engage in certain other transactions without the prior consent of the lenders.

Our credit agreement also requires us to maintain compliance with the following financial ratios:

- a current ratio, which is the ratio of our consolidated current assets (including unused commitments under our credit facility and excluding non-cash assets related to asset retirement obligations ("AROs") and derivatives) to our consolidated current liabilities (excluding the current portion of long-term debt under our credit agreement and non-cash liabilities related to AROs and derivatives), as of the last day of each fiscal quarter, of not less than 1.0 to 1.0; and
- a leverage ratio, which is the ratio of our consolidated Debt (as defined in our credit agreement) as of the last day of each fiscal quarter, subject to certain exclusions (as described in our credit agreement) to consolidated EBITDAX (as defined in our credit agreement) for the last 12 months ending on the last day of that fiscal quarter, of not greater than 4.0 to 1.0.

Further, under our credit agreement, we are only permitted to hedge up to the greater of 85% of our proved reserves and 75% of our reasonably anticipated production for up to 24 months in the future, and up to the greater of 75% of our proved reserves and 50% of our reasonably anticipated production for 25 to 60 months in the future, provided that no hedges may have a term beyond five years. We are currently required to hedge a minimum of 75% of our projected oil volumes from PDP reserves for each calendar month on a two-year rolling basis; however, we do not anticipate that the amended and restated credit facility we will enter into in connection with this offering will contain similar minimum hedging requirements.

Contractual Obligations

A summary of our contractual obligations as of December 31, 2015 is provided in the following table:

	Payments Due by Period for the Year Ending December 31,						
	2016	2017	2018	2019	2020	Thereafter	Total
				(in thousands)			
Credit facility(1)	$ —	$ —	$ —	$—	$20,000	$—	$20,000
Operating leases(2)	737	703	525	—	—	—	1,965
Service and purchase contracts(3)	1,057	—	—	—	—	—	1,057
Rig contracts	240	—	—	—	—	—	240
Total	$2,034	$703	$525	$—	$20,000	$—	$23,262

(1) This table does not include future commitment fees, amortization of deferred financing costs, interest expense or other fees on our credit facility because obligations thereunder are floating rate instruments and we cannot determine with accuracy the timing of future loan advances, repayments or future interest rates to be charged. As of December 31, 2016, we had $132.0 million outstanding under our credit facility and $28.0 million of additional borrowing capacity available. We intend to use a portion of the net proceeds from this offering to fully repay borrowings under our credit facility. Please see "Use of Proceeds". We also anticipate that we will amend and restate our credit facility in connection with this offering to, among other things, increase the borrowing base and aggregate commitments thereunder.

(2) Primarily relates to the lease of our corporate offices.

(3) Primarily relates to our obligation to purchase lease automatic custody transfer units in conjunction with oil gathering for current and future wells.

Quantitative and Qualitative Disclosure About Market Risk

We are exposed to market risk, including the effects of adverse changes in commodity prices and interest rates as described below. The primary objective of the following information is to provide quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil and natural gas prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. All of our market risk sensitive instruments were entered into for purposes other than speculative trading.

Commodity Price Risk

Our major market risk exposure is in the pricing that we receive for our oil, natural gas and NGLs production. Pricing for oil, natural gas and NGLs has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. During the period from January 1, 2014 through September 30, 2016, the WTI spot price for oil has declined from a high of $107.95 per Bbl on June 20, 2014, to $26.19 per Bbl on February 11, 2016. NGL prices generally correlate to the price of oil, and accordingly prices for these products have likewise declined and are likely to continue following that market. Prices for domestic natural gas began to decline during the third quarter of 2014 and have continued to be weak throughout 2015 and thus far in 2016. During the period from January 1, 2014 through September 30, 2016, the Henry Hub spot price for natural gas has declined from a high of $8.15 per MMBtu on February 10, 2014, to a low of $1.49 per MMBtu on March 4, 2016. The prices we receive for our oil, natural gas and NGLs production depend on numerous factors beyond our control, some of which are discussed in "Risk Factors—Risks Related to Our Business—Oil, natural gas and NGL prices are volatile. A further reduction or sustained decline in oil, natural gas and NGL prices could adversely affect our business, financial condition and results of operations and our ability to meet our capital expenditure obligations and financial commitments".

A $1.00 per barrel change in our realized oil price would have resulted in a $0.7 million change in oil revenues for 2015. A $0.10 per Mcf change in our realized natural gas price would have resulted in a $0.04 million change in our natural gas revenues for 2015. A $1.00 per barrel change in NGL prices would have changed NGL revenue by $0.09 million for 2015. Oil sales contributed 93% of our total revenues for 2015. Natural gas sales contributed 3% and NGL sales contributed 4% of our total revenues for 2015. Our oil, natural gas and NGL revenues do not include the effects of derivatives.

Due to this volatility, we expect to use commodity derivative instruments such as collars, swaps and basis swaps to hedge price risk associated with our oil production. These hedging instruments will allow us to reduce, but not eliminate, the potential variability in cash flow from operations due to fluctuations in oil prices. This will provide increased certainty of cash flows for funding our drilling program and debt service requirements. These instruments provide only partial price protection against declines in oil prices and may partially limit our potential gains from future increases in prices. We may seek to hedge price risk associated with our natural gas and NGL production in the future. Under our credit agreement, we are only permitted to hedge up to the greater of 85% of our proved reserves and 75% of our reasonably anticipated production for up to 24 months in the future, and up to the greater of 75% of our proved reserves and 50% of our reasonably anticipated production for 25 to 60 months in the future, provided that no hedges may have a term beyond five years. We are currently required to hedge a minimum of 75% of our projected oil volumes from PDP reserves for each calendar month on a two-year rolling basis; however, we do not anticipate that the amended and restated credit facility we will enter into in connection with this offering will contain similar minimum hedging requirements.

The table below presents our open hedge positions as of December 31, 2016:

Description & Production Period	Volume (Bbl)	Swap Price ($/Bbl)(1)
Crude Oil Swaps:		
January 2017 - December 2017	437,200	$41.80
January 2017 - December 2017	109,400	$46.00
January 2017 - December 2017	54,750	$50.75
January 2017 - December 2017	91,250	$51.25
January 2017 - December 2017	100,375	$52.25
January 2017 - December 2017	91,250	$53.55
January 2017 - December 2017	91,250	$53.70
January 2017 - December 2017	182,500	$55.00
January 2017 - June 2017	54,025	$50.00
July 2017 - September 2017	23,000	$50.00
January 2018 - March 2018	86,750	$47.00
January 2018 - June 2018	27,150	$51.50
January 2018 - June 2018	36,200	$52.75
January 2018 - June 2018	40,725	$53.75
January 2018 - March 2018	29,250	$51.30
January 2018 - December 2018	91,250	$53.60
January 2018 - December 2018	91,250	$53.65
January 2018 - December 2018	182,500	$56.00
April 2018 - June 2018	83,400	$47.50
April 2018 - June 2018	25,025	$51.55
July 2018 - September 2018	78,200	$52.00
July 2018 - September 2018	34,500	$53.25
July 2018 - September 2018	34,500	$54.25
July 2018 - September 2018	69,000	$55.25
October 2018 - December 2018	64,400	$56.00

(1) Reference price is NYMEX WTI price.

Counterparty and Customer Credit Risk

Our derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require counterparties to our derivative contracts to post collateral, we do evaluate the credit standing of such counterparties as we deem appropriate. The counterparties to our derivative contracts currently in place have investment grade ratings.

Our principal exposures to credit risk are through receivables resulting from joint interest receivables and receivables from the sale of our oil and natural gas production due to the concentration of our oil and natural gas receivables with several significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Joint operations 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 intend to drill. We have little ability to control whether these entities will participate in our wells.

Interest Rate Risk

At September 30, 2016, we had $90.0 million of debt outstanding, with an assumed weighted average interest rate of 3.54%. Interest is calculated under the terms of our credit agreement based on the greatest of certain specified base rates plus an applicable margin that varies based on utilization. Assuming no change in the amount outstanding, the impact on interest expense of a 1% increase or decrease in the assumed weighted average interest rate would be approximately $0.9 million per year. We do not currently have any derivative arrangements to protect against fluctuations in interest rates applicable to our outstanding indebtedness.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our predecessor's consolidated financial statements, which have been prepared in accordance with GAAP. The preparation of our predecessor's financial statements requires it to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. Changes in facts and circumstances or additional information may result in revised estimates, and actual results may differ from these estimates.

A complete list of our predecessor's significant accounting policies are described in the notes to our predecessor's audited financial statements for the year ended December 31, 2015, included elsewhere in this prospectus.

Successful Efforts Method of Accounting for Oil and Natural Gas Activities

Our oil and natural gas exploration and developments costs are accounted for using the successful efforts method. Under the successful efforts method, all costs incurred related to the acquisition of oil and natural gas properties and the costs of drilling development wells and successful exploratory wells are capitalized, while the costs of unsuccessful exploratory wells are expensed if and when the well is determined not to have found reserves in commercial quantities. Other items charged to expenses generally include geological and geophysical costs, delay rentals and lease and well operating costs.

Capitalized leasehold costs attributable to proved properties are depleted using the units-of-production method based on proved reserves on a field basis. Capitalized well costs, including asset retirement obligations, are depleted based on proved developed reserves on a field basis.

Proved Oil and Natural Gas Properties. Capitalized leasehold costs attributable to proved properties are depleted using the units-of-production method based on proved reserves on a field basis. Capitalized well costs, including asset retirement obligations, are depleted based on proved developed reserves on a field basis.

Unproved Properties. Unproved oil and natural gas properties consist of costs to acquire undeveloped leases and unproved reserves, and are capitalized when incurred. When a successful well is drilled on undeveloped leasehold or reserves are otherwise attributable to a property, unproved property costs are transferred to proved properties.

Exploration Costs. Exploration costs consist of costs incurred to identify and evaluate areas that are prospective for oil and natural gas reserves. Explorations costs include geological and geophysical costs, delay rentals and unsuccessful exploratory wells.

Exploratory Well Costs. Exploratory well costs are capitalized as incurred pending determination of whether the well has discovered proved commercial reserves. If the exploratory well is determined to be unsuccessful, the cost of the well is transferred to expense.

Impairment of Oil and Natural Gas Properties

Proved oil and natural gas properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying amount of such property. We estimate the expected future cash flows of oil and natural gas properties and compare these undiscounted cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will write down the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, cash flow from commodity hedges, estimated future capital expenditures and a commensurate discount rate.

Unproved properties are periodically assessed for impairment on a property-by-property basis. We evaluate significant unproved properties for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or future plans to develop acreage, and record impairment expense for any decline in value.

Oil and Natural Gas Reserve Quantities

We engage Ryder Scott, our independent petroleum engineer, to prepare our total estimated proved reserves. We expect proved reserve estimates will change as additional information becomes available and as commodity prices and operating and capital costs change. We evaluate and estimate our proved reserves each year-end. For purposes of depletion and impairment, reserve quantities are adjusted in accordance with GAAP for the impact of additions and dispositions. Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. It is possible that, because of changes in market conditions or the inherent imprecision of reserve estimates, the estimates of future cash inflows, future gross revenue, the amount of oil and natural gas reserves, the remaining estimated lives of oil and natural gas properties or any combination of the above may be increased or reduced. Increases in recoverable economic volumes generally reduce per unit depletion rates while decreases in recoverable economic volumes generally increase per unit depletion rates.

Derivative Instruments

We utilize commodity derivative instruments to manage our exposure to commodity price volatility. All of our commodity derivative instruments are utilized to manage price risk attributable to our expected production, and we do not enter into such instruments for speculative trading purposes. We do not designate any derivative instruments as cash flow hedges for financial reporting purposes. We record all derivative instruments on the balance sheet as either assets or liabilities measured at their estimated fair value. We record gains and losses from the change in fair value of derivative instruments in current earnings as they occur. We do not currently utilize any derivative instruments to manage exposure to variable interest rates, but may do so in the future.

Asset Retirement Obligations

Our asset retirement obligations relate to future costs associated with the plugging and abandonment of oil and natural gas wells, removal of equipment and facilities from leased acreage and restoration in accordance with local, state and federal laws. The discounted fair value of an asset retirement obligation liability is required to be recognized in the period in which it is incurred, with the associated asset retirement capitalized in proved oil and natural gas property costs as part of the carrying cost of the oil and natural gas asset. The recognition of the asset retirement obligation requires management to make numerous assumptions regarding such factors as the estimated probabilities, amounts and timing of settlements, credit-adjusted risk-free discount rates, inflation rates and future advance in technology. In periods subsequent to the initial measurement of the asset retirement obligation, we recognize period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the asset retirement obligation liability due to the passage of time impact net earnings and accretion expense. The related capital cost, including revisions thereto, is charged to expense through accumulated depletion, depreciation, amortization and accretion.

We recognize an estimated liability for future costs associated with the abandonment of our oil and natural gas properties. A liability for the fair value of an asset retirement obligation and corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is spud or acquired. The increase in carrying value is included in proved oil and natural gas properties in the balance sheet. We deplete the amount added to proved oil and natural gas property costs and recognize expenses in connection with the accretion of the discounted liability over the remaining economic lives of the respective wells.

Recently Issued Accounting Pronouncements

In March 2016, the FASB issued Accounting Standard Update ("ASU") 2016-09, "Compensation—Stock Compensation Topic 718: Improvements to Employee Share-Based Payment Accounting", which simplifies several aspects of the accounting for share-based payment award transactions. These simplifications include the income tax consequences, classification of awards as either equity or liabilities and classification on the statement of cash flows. ASU 2016-09 will be effective for reporting periods beginning on or after December 15, 2016, and early adoption is permitted. We are currently evaluating the impact of its pending adoption of this guidance on our consolidated financial statements.

In February 2016, the FASB issued ASU 2016-02, "Leases (Topic 842)", which requires all lease transactions with terms in excess of 12 months to be recognized on the balance sheet as lease assets and lease liabilities. ASU 2016-02 becomes effective on January 1, 2019, and requires the use of the modified retrospective transition method. Although early application is permitted, we do not intend to early adopt the new standard. We are currently evaluating the impact of its pending adoption of this guidance on our consolidated financial statements.

In April 2015, the FASB issued ASU 2015-03, *Interest—Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs*. This ASU changes the presentation of debt issuance costs in the financial statements, and requires that debt issuance costs be presented in the balance sheet as a direct reduction from the carrying amount of the corresponding debt liability, consistent with debt discounts. As the guidance in this ASU did not address presentation or subsequent measurement of debt issuance costs related to line-of-credit arrangements, the FASB issued ASU 2015-15, *Interest—Imputation of Interest: Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements* in August 2015 to clarify that these presentation requirements did not apply to line-of-credit arrangements. ASU 2015-03 is effective for the annual periods beginning after December 15, 2016 and for interim periods within that annual period, and is required to be adopted retrospectively. ASU 2015-15 is effective upon adoption of ASU 2015-03. We do not expect the adoption of these standards will have a material impact on our consolidated financial statements.

In May 2014, the FASB issued ASU 2014-09, "Revenue from Contracts with Customers (Topic 606)", which establishes a comprehensive new revenue recognition standard. ASU 2014-09 allows for the use of either the full or modified retrospective transition method, and the standard will be effective for annual reporting periods beginning after December 15, 2017 including interim periods within that period, with early adoption permitted only for annual reporting periods beginning after December 15, 2016. We are currently evaluating which transition approach to use and the impact of the adoption of this standard on our consolidated financial statements.

Other than as disclosed above, there are no other new accounting standards that would have a material impact on our condensed consolidated financial statements and disclosures.

Internal Controls and Procedures

We are not currently required to comply with the SEC's rules implementing Section 404 of the Sarbanes Oxley Act of 2002, and are therefore not required to make a formal assessment of the effectiveness of our internal control over financial reporting for that purpose. Upon becoming a public company, we will be required to comply with the SEC's rules implementing Section 302 of the Sarbanes-Oxley Act of 2002, which will require our management to certify financial and other information in our quarterly and annual reports and provide an annual management report on the effectiveness of our internal control over financial reporting. We will not be required to make our first assessment of our internal control over financial reporting under Section 404 until our first annual report subsequent to our ceasing to be an "emerging growth company" within the meaning of Section 2(a)(19) of the Securities Act.

Inflation

Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2015 or 2014. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy and we tend to experience inflationary pressure on the cost of oilfield services and equipment as increasing oil and natural gas prices increase drilling activity in our areas of operations.

Off-Balance Sheet Arrangements

Currently, neither we nor our predecessor have any material off-balance sheet arrangements.

BUSINESS

The following discussion should be read in conjunction with the "Selected Historical Consolidated Financial Data" and the accompanying financial statements and related notes included elsewhere in this prospectus.

The estimated proved reserve information for our properties as of November 30, 2016 and December 31, 2015 and 2014, contained in this prospectus is based on a reserve report relating to our properties prepared by Ryder Scott, our independent petroleum engineer.

Our Company

Business Overview

We are a growth-oriented, independent oil and natural gas company focused on the acquisition and development of unconventional oil and associated liquids-rich natural gas reserves in the Southern Delaware Basin, a sub-basin of the Permian Basin of West Texas and one of the most prolific unconventional resource plays in North America. Our acreage is located on large, contiguous blocks in the adjacent counties of Winkler, Ward, Reeves and Pecos, with significant original oil-in-place within multiple stacked hydrocarbon-bearing formations. We are focused on increasing stockholder value by (i) growing production and reserves through the development of our multi-year inventory of 1,265 gross horizontal drilling locations with an average lateral length of 7,426 feet, (ii) expanding and improving the resource potential of our existing acreage position and (iii) growing our acreage position through acquisitions and leasing efforts.

As of September 30, 2016, we held an average 89% working interest in approximately 68,121 gross (60,875 net) leased or acquired acres, and we operated approximately 98% of our acreage position. Both our production and our proved reserves consist of greater than 80% oil. Our acreage is exclusively located in the core oil window of the Southern Delaware Basin. We generally consider the core oil window of the Southern Delaware Basin to be the eastern and southern portion of the basin, which is characterized by high oil saturation and favorable over-pressured conditions.

Jagged Peak was formed in April 2013 by an affiliate of Quantum Energy Partners, a leading energy private equity firm that has managed more than $11 billion of equity commitments since 1998, and key members of our management team. Our management and technical teams, which have extensive engineering, geoscience, land, marketing and finance capabilities, are led by Joseph N. Jaggers, an industry veteran with over 35 years of experience growing oil and natural gas operations. Mr. Jaggers and his teams have a proven track record of achieving significant production and reserve growth in unconventional plays in the United States, including at Ute Energy, LLC, where Mr. Jaggers served as President and Chief Executive Officer, and at Bill Barrett Corporation, where he served as President and Chief Operating Officer.

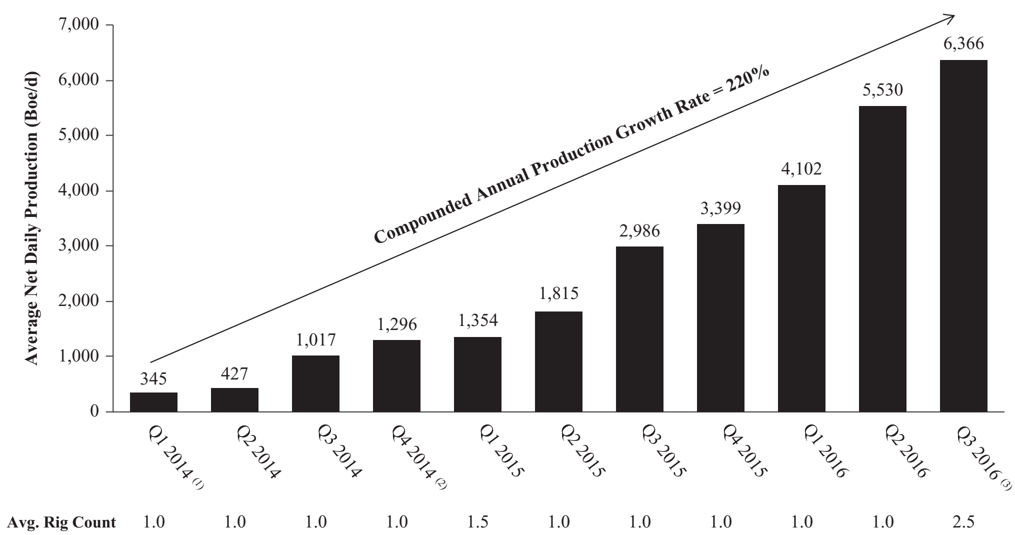
We were formed with the goal of building a premier acquisition and development company focused on horizontal drilling in the core oil window of the Southern Delaware Basin. We plan to achieve this goal by using advanced drilling and completion techniques and leveraging our management team's extensive experience and technical expertise. At our inception, we specifically targeted the Southern Delaware Basin due to the abundant amount of oil-in-place, stacked pay potential, low breakeven-prices, attractive well economics, favorable operating environment and in-place midstream infrastructure. We have assembled our current acreage position by executing privately sourced acquisitions of largely underdeveloped acreage and through grassroots leasing.

As of September 30, 2016, we have drilled and completed 16 horizontal wells. Based on the wells we have drilled to date and wells drilled by other operators, we believe the Lower Wolfcamp A, Upper Wolfcamp A, Wolfcamp B and 3rd Bone Spring Sand formations are significantly delineated across our acreage. The top of the Wolfcamp formation ranges from approximately 8,850 feet to 11,420 feet, and the top of the Bone Spring formation ranges from approximately 8,600 feet to 10,900 feet. We also believe that significant additional development opportunities exist on our acreage in the Brushy Canyon, Avalon Shale, 1st Bone Spring Lime, 1st Bone Spring Sand, 2nd Bone Spring Sand, 3rd Bone Spring Lime and Wolfcamp C formations.

Our contiguous acreage position enables the drilling of long laterals, resulting in significant drilling efficiencies that enhance the economic development of our acreage position. The ability to drill long-lateral wells improves our returns by (i) increasing our EUR per well, (ii) allowing us to contact more reservoir rock with fewer vertical wellbores (thus reducing drilling and completion costs on a per unit basis) and (iii) allowing us to hold more acreage per horizontal well drilled. Additionally, the contiguous nature of our acreage provides economies of scale by allowing us to better share our infrastructure.

Since commencing our drilling program in late 2013, we have consistently increased EURs and improved our well and field-level returns by refining our landing zones, drilling longer length laterals and enhancing our completion techniques. Over the same period, we have also improved our returns by reducing our drilling times and drilling and completion costs. We expect that continued optimization in the field, employment of pad drilling and expansion of our infrastructure will further increase stockholder value.

The prolific nature of our long-lateral horizontal drilling locations and continually modified and improved completion designs have allowed us to increase our average net daily production from 345 Boe/d in the first quarter of 2014 (normalized for five days of production) to 6,366 Boe/d in the third quarter of 2016 while operating an average of one horizontal drilling rig through June 30, 2016. We began operating our second and third rigs in July of 2016 and, in 2017, we expect our drilling program to grow to six horizontal rigs, allowing us to continue our rapid production growth. Assuming this 2017 level of drilling activity, we have over 26 years of drilling inventory. The chart below shows our historical production over time.



(1) Q1 2014 production normalized for five days of production.

(2) The increase in production from Q3 2014 to Q4 2014 was partially attributable to the acquisition of three producing wells in September 2014 with average daily production of 74 Boe/d during Q4 2014.

(3) We added our second and third rigs during July 2016. There were no completions or production attributable to these rigs as of September 30, 2016.

We have made a strategic decision to construct and operate water handling infrastructure within our project areas, which allows us to consistently realize significant operating and cost efficiencies. We intend to install additional water handling infrastructure to accommodate our projected future production growth. Our infrastructure strategy includes owning a sufficient amount of surface acreage in our project areas to control both fresh water supply for drilling and completions and disposal of flowback and produced water.

As of September 30, 2016, we had identified 1,265 gross horizontal drilling locations in the Lower Wolfcamp A, the Upper Wolfcamp A, the Wolfcamp B and the 3rd Bone Spring Sand formations, assuming 880-foot spacing in an offset pattern and a minimum vertical separation of 175 feet within target formations. 69% of our identified locations are classified as long or extra-long laterals, with an average length of 8,806 feet. We expect to significantly add to our drilling inventory over time as we continue to decrease the horizontal and vertical spacing of horizontal wells, acquire additional acreage and establish the productive capability of additional zones.

We classify our acreage position into three project areas: Whiskey River, Cochise and Big Tex. As of September 30, 2016, we had drilled and completed eight operated wells in the Whiskey River project area targeting the Lower Wolfcamp A, Upper Wolfcamp A and Wolfcamp B. We had drilled and completed six operated wells in the Cochise project area targeting the Lower Wolfcamp A. We had drilled and completed two operated wells in the Big Tex project area targeting the Lower Wolfcamp A. The following table provides a summary of our gross horizontal drilling locations by project area, targeted formation and lateral length as of September 30, 2016.

Gross Identified Horizontal Drilling Locations(1)(2)(3)

	Cochise	Whiskey River	Big Tex	Totals
By Target				
3^{rd} Bone Spring Sand	66	225	—	291
Upper Wolfcamp A	53	171	84	308
Lower Wolfcamp A	57	219	99	375
Wolfcamp B	66	225	—	291
Total Locations	242	840	183	1,265
By Lateral Length Category				
Extra Long (Two Sections)	175	355	76	606
Long (One and One-Half Sections)	46	151	72	269
Standard (One Section)	21	334	35	390
Total Locations	242	840	183	1,265
Avg. Completed Lateral Length (in feet)				
Extra Long	9,587	9,534	9,480	9,543
Long	6,900	7,273	7,041	7,147
Standard	4,290	4,358	4,071	4,328
Gross Acres	12,894	35,912	19,315	68,121
Net Acres	12,244	30,796	17,835	60,875
Avg. Working Interest	95.0%	85.8%	92.3%	89.4%

(1) Our total identified horizontal drilling locations include 26 locations associated with proved undeveloped reserves as of November 30, 2016. We have estimated our drilling locations based on well spacing assumptions and upon the evaluation of our horizontal drilling results and those of other operators in our area, combined with our interpretation of available geologic and engineering data. The drilling locations that we actually drill will depend on the availability of capital, regulatory approvals, commodity prices, costs, actual drilling results and other factors. Any drilling activities we are able to conduct on these identified locations may not be successful and may not result in additional proved reserves. Further, to the extent the drilling locations are associated with acreage that expires, we would lose our right to develop the related locations. See "Risk Factors—Risks Related to Our Business—Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill such locations".

(2) Our horizontal drilling location count implies 880-foot spacing in an offset pattern and minimum vertical separation of 175 feet.

(3) 1,186 of our 1,265 horizontal drilling locations are on acreage that we operate. We have an 89% average working interest in our acreage.

For the month ended September 30, 2016, our average net daily production was 6,601 Boe/d, of which approximately 83% was oil, 9% was NGLs and 8% was natural gas. Of this production, approximately 44%, 45% and 11% were attributable to our Cochise, Whiskey River and Big Tex project areas, respectively. The following table provides summary information regarding our proved reserves as of November 30, 2016, based on a reserve report prepared by Ryder Scott, a third-party engineering firm.

Estimated Total Proved Reserves						
Oil (MMBbls)	NGLs (MMBbls)	Natural Gas (Bcf)	Total (MMBoe)	% Oil	% Liquids(1)	% Developed
26.4	3.8	15.3	32.7	80.7	92.2	39.7

(1) Includes oil and NGLs.

The following table presents data on Jagged Peak's operated horizontal wells drilled and completed since commencement of our drilling program in late 2013 through November 30, 2016.

Year of First Production	Well Count	Average Completed Lateral Length (feet)	Average Oil Equivalent EUR (2) (MBbls)	Average Oil Equivalent EUR per 1,000' (2) (MBbls)	Average Drilling and Completion Costs per 1,000' (in thousands)
2014(1)	3	6,556	649	99	$2,517
2015	7	9,164	950	104	1,481
2016 through 11/30	9	9,134	1,036	113	1,100

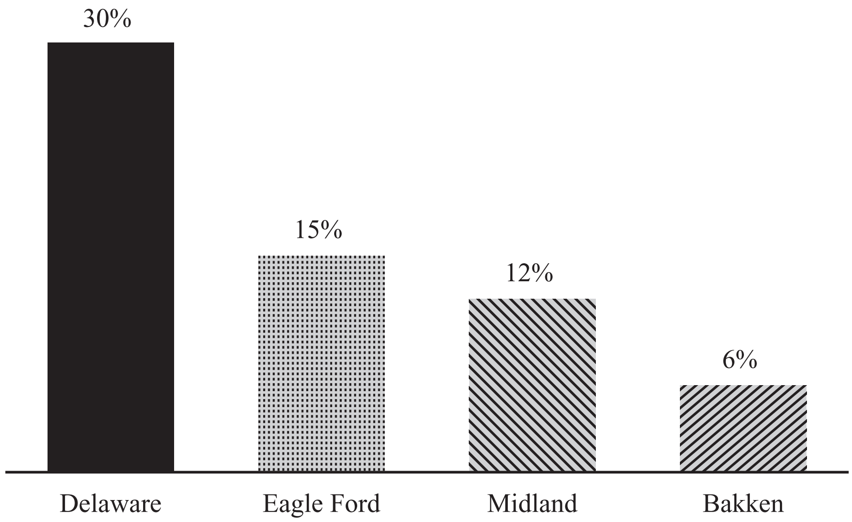
(1) Does not include the results of one well that was drilled in 2014, but was not completed in accordance with our completion design due to mechanical issues.

(2) EUR represents the sum of gross reserves remaining as of a given date and cumulative production as of that date. EUR is based on the estimated gross reserves attributable to each location in our reserve report as of November 30, 2016. Average EUR for the nine wells drilled and completed during the eleven months ended November 30, 2016, includes the results of our six most recent wells drilled and completed in our Whiskey River and Cochise project areas targeting the Wolfcamp A formation, each of which utilized the continued optimization and refinement of our advanced drilling and completion techniques. These six wells had an average EUR of 1,136 MBbls as of November 30, 2016.

The Permian Basin is an attractive operating area due to its multiple stacked hydrocarbon-bearing formations that are prospective for horizontal development. The basin is further characterized by a favorable operating environment, high oil and liquids-rich natural gas content, significant in-place midstream infrastructure, a well-developed network of oilfield service providers, long-lived reserves with consistent geologic attributes and reservoir quality and historically high development success rates. According to the Energy Information Administration of the U.S. Department of Energy, the Permian Basin is the most prolific oil producing area in the United States, accounting for 25% of total U.S. crude oil production during September 2016.

Over the past decade, the Delaware Basin has experienced significant growth in horizontal drilling activity. According to Baker Hughes, as of September 30, 2016, the Permian Basin remains the most active basin in the United States based on 167 active horizontal rigs, with the Delaware Basin representing approximately 50% of that activity. From January 2013 through September 30, 2016, production in the Delaware Basin has grown at a 30% compounded annual production growth rate, outpacing other regions in the United States, as illustrated in the following chart.

Compounded Annual Production Growth Rate for Major Oil Basins and Plays
(January 2013 to September 2016)



Source: Wood Mackenzie as of September 2016.

Business Strategies

Our primary business objective is to increase stockholder value through the execution of the following strategies:

- ***Economically grow production, cash flow and reserves by developing our extensive drilling inventory in the core oil window of the Southern Delaware Basin***. Our technical acumen and horizontal drilling expertise have enabled us to drill highly productive horizontal wells in multiple formations. While operating an average of one horizontal drilling rig through June 30, 2016, we grew our average net daily production from 345 Boe/d in the first quarter of 2014 (normalized for five days of production) to 6,366 Boe/d in the third quarter of 2016, representing a compounded annual production growth rate of 220%. We began operating our second and third rigs in July of 2016 and, in 2017, we expect our drilling program to grow to six horizontal rigs, allowing us to continue our rapid production growth. We intend to continue to economically grow production, cash flow and reserves by utilizing our technical expertise to develop our multi-year drilling inventory while efficiently allocating capital to maximize the value of our resource base.

- ***Expand drilling inventory over time.*** In addition to the 1,265 gross horizontal locations identified in the Lower Wolfcamp A, the Upper Wolfcamp A, the Wolfcamp B and the 3^{rd} Bone Spring Sand formations, we intend to add to our drilling inventory over time as we (i) decrease the horizontal and vertical spacing of our horizontal wells, (ii) acquire additional acreage by leveraging our technical acumen and horizontal drilling expertise to identify strategic acquisition opportunities and (iii) establish the productive capability of additional zones.

- ***Maximize returns by optimizing drilling and completion techniques through the experience and expertise of our management and technical teams.*** Our experienced management and technical teams have a proven track record of optimizing drilling and completion techniques to drive well and field-level returns. We have experienced a significant decrease in our drilling and completion costs since 2014. This trend has been driven by efficiency improvements in the field, including reduced drilling days, the modification of well designs and a continued focus on procurement throughout our operations. In addition, we believe our contiguous acreage position and our ability to drill long-lateral wells will enhance our returns by increasing our EUR per well, reducing drilling and completion costs and providing economies of scale by allowing us to better share our infrastructure.

- ***Strategically manage infrastructure and midstream services contracts to lower our costs.*** We vigorously pursue cost reductions throughout our operations. We have made a strategic decision to construct and operate water handling infrastructure within our project areas to enable us to achieve high operating efficiency. We intend to install additional water handling infrastructure capacity to accommodate our projected future production growth. Our oil and natural gas gathering and transportation contracts are structured as acreage dedications, which allows us to avoid incurring fees or penalties associated with minimum volume commitments.

- ***Leverage extensive industry experience to evaluate and execute strategic acquisitions.*** Our management and technical teams have an extensive track record of forming and building businesses in North American resource plays. We also have significant experience in successfully sourcing, evaluating and executing acquisition opportunities, including multiple privately sourced acquisitions that make up the majority of our current acreage position. We regularly initiate and review acquisition opportunities and intend to pursue future acquisitions that meet our strategic and financial objectives. We believe our understanding of the geology, geophysics and reservoir properties of potential acquisition targets will allow us to identify and acquire highly prospective acreage in order to grow our resource base and maximize stockholder value.

- ***Maintain a high degree of operational control.*** We seek to maintain operational control of our properties in order to better execute on our strategy of enhancing returns through operating improvements and cost efficiencies. As the operator of approximately 98% of our acreage, we are able to effectively manage (i) the timing and level of our capital spending, (ii) our development drilling strategies and (iii) our operating costs. We believe this flexibility to manage our development program allows us to optimize our field-level returns and profitability.

- ***Preserve financial flexibility to pursue organic and external growth opportunities.*** We seek to maintain a conservative financial position. We expect to fund our growth with cash flow from operations, availability under our credit facility, which we expect to amend and restate in connection with this offering to, among other things, increase the aggregate commitments thereunder, and capital markets offerings when appropriate. We intend to continue allocating capital in a disciplined manner and proactively manage our cost structure to achieve our business objectives. Consistent with our disciplined approach to financial management, we expect to maintain an active hedging program that seeks to reduce our exposure to commodity price volatility and protect our cash flow, returns and the funding of our capital program.

Our Competitive Strengths

We believe that the following strengths will allow us to successfully execute our business strategies:

- ***Attractive portfolio of contiguous acreage in the core oil window of the Southern Delaware Basin***. Our current leasehold acreage is located in the oil-rich southern portion of the Delaware Basin in Winkler, Ward, Reeves and Pecos Counties. This acreage is characterized by a multi-year, oil-weighted inventory of horizontal drilling locations that provide attractive growth and return opportunities. As of November 30, 2016, our estimated proved reserves consisted of 80.7% oil, 11.5% NGLs and 7.8% natural gas. The extensive original oil-in-place, favorable over-pressured conditions and other attractive geologic characteristics of the Southern Delaware Basin give us a high degree of confidence in our current drilling inventory.

- ***Large horizontal drilling inventory and significant number of long-lateral wells across multiple pay formations***. We have identified a multi-year inventory of 1,265 gross horizontal drilling locations with an average lateral length of 7,426 feet. 69% of our identified locations are classified as long or extra-long laterals, with an average length of 8,806 feet. We believe our extensive inventory of long and extra-long lateral locations will generate superior economic returns relative to shorter laterals. Assuming six rigs in operation, which is our 2017 level of budgeted drilling activity, we have over 26 years of drilling inventory. We intend to significantly add to our drilling inventory over time as we continue to reduce and refine well spacing, acquire additional acreage and establish the productive capability of additional zones.

- ***Proven horizontal drilling expertise and technical acumen in the Delaware Basin.*** We believe our horizontal drilling and multi-stage fracturing stimulation experience in the Delaware Basin provides us with a competitive strength. Since commencement of our drilling program in late 2013, we have substantially reduced drilling days for our horizontal wells. The average time from spud to rig release for our seven horizontal wells drilled during the nine months ended September 30, 2016 was approximately 42 days, compared to an average of 67 days for the thirteen horizontal wells we drilled in 2015 and 2014. In addition, we continually modify our completion design to optimize the performance of our wells and expect to realize further drilling efficiencies going forward.

- ***High degree of operational control.*** We are the operator of approximately 98% of our acreage. This operating control allows us to better execute our strategies of enhancing returns through operational and cost efficiencies and increasing ultimate hydrocarbon recovery. As the operator of substantially all of our acreage, we retain the flexibility to adjust our capital expenditures based on the prevailing commodity price environment and other factors. We also believe that our significant level of operational control will enable us to implement pad drilling and other drilling and completion optimization strategies, which will result in the continued reduction of spud-to-rig release days, engineered completion designs and efficient use of infrastructure.

- ***Highly effective and cost efficient water sourcing, transportation, storage and disposal.*** Our infrastructure strategy includes owning sufficient tracts of surface acreage to (i) allow us to control fresh water supply for drilling and completions, (ii) provide ease of pipeline installation, (iii) allow construction of storage for both fresh and produced water and (iv) simplify construction of facilities for disposal of flowback and produced water. In addition, we have supplemental agreements that provide for fresh water sourcing and produced water storage and disposal services from adjacent landowners. As of September 30, 2016, our installed and contracted capacities were (i) 4.7 million barrels of water storage capacity, (ii) 10.5 miles of fresh water pipelines and 63.6 miles of produced water transportation pipelines, which allows us to largely eliminate water trucking in all phases of our operation, (iii) 162 thousand barrels per day of water sourcing capacity and (iv) 86 thousand barrels per day of water disposal capacity. Accordingly, we have disposal capacity more than three times our current produced water volumes and sufficient sources of fresh water to support our current drilling program, and we believe it is scalable to support additional rigs. This infrastructure position provides important cost advantages compared to utilizing third-party services.

- ***Experienced and incentivized management team.*** With an average of 32 years of industry experience, our senior management team has a proven track record of building and running successful businesses focused on the acquisition and development of oil and natural gas properties and enhancing returns through operational efficiencies. Prior to forming Jagged Peak, a subset of our management team, including Joseph N. Jaggers, our Chief Executive Officer and President, and Gregory S. Hinds, our Executive Vice President, Development Planning & Acquisitions, led the growth of Ute Energy LLC's upstream oil and natural gas assets to over 7,800 Boe/d of production and over 156,800 net acres of undeveloped properties and built a natural gas gathering and processing network servicing Ute Energy and other third parties in the Uinta Basin. In November 2012, Ute Energy's upstream and midstream subsidiaries were sold for consideration in excess of $1.0 billion. We believe our team's experience building and operating multiple successful upstream oil and natural gas companies provides us with a distinct competitive advantage. Additionally, after giving effect to this offering, our management team and other employees will hold approximately 10.8% of our common stock, which provides a meaningful incentive to increase the value of our business for the benefit of all stockholders.

- ***Conservatively capitalized balance sheet and strong liquidity profile.*** After giving effect to this offering and the use of proceeds therefrom, we expect to have no outstanding debt, $180.0 million of borrowing capacity under our credit facility and approximately $294.2 million of cash on the balance sheet (based on our cash balance as of September 30, 2016). We believe our borrowing capacity, cash on hand and cash flow from operations will provide us with sufficient liquidity to execute our 2017 capital program.

Our Properties

Our properties include working interests in approximately 68,121 gross (60,875 net) acres, all of which are located in Winkler, Ward, Reeves and Pecos Counties in the oil-rich core of the Southern Delaware Basin. The Southern Delaware Basin is a sub-basin of the Permian Basin of West Texas characterized by high oil saturation and favorable over-pressured conditions. We view our acreage position in three distinct project areas: Whiskey River, Cochise and Big Tex. The following table summarizes our acreage by project area as of September 30, 2016.

	Gross	Net
Project Area:		
Whiskey River	35,912	30,796
Cochise	12,894	12,244
Big Tex	19,315	17,835
Total	68,121	60,875

Permian Basin. The Permian Basin consists of mature, legacy, onshore oil and liquids-rich natural gas reservoirs that span approximately 86,000 square miles in West Texas and New Mexico. The Basin is composed of five sub regions: The Delaware Basin, the Central Basin Platform, the Midland Basin, the Northwest Shelf and the Eastern Shelf. The Permian Basin is an attractive operating area due to its multiple stacked hydrocarbon-bearing formations that are prospective for horizontal development. The basin is further characterized by a favorable operating environment, high quality oil and liquids-rich natural gas reservoirs, well-developed network of oilfield service providers, long-lived reserves from well-understood geologic features of predictable reservoir quality with historically high development success rates.

Delaware Basin. The present-day structural configuration of the Delaware Basin, a well-defined sub-basin of the larger Permian, began to take shape in the early Pennsylvanian period when movement on deep faults caused uplift of the adjacent Central Basin Platform. This period was characterized by deposition of marine shales interbedded with limestones and marls with periodic influxes of siliciclastic sediments during relative lowstands of sea-level. In early Permian time, the stratigraphic record reflects a rapid deepening of the Delaware Basin. Deep-basin anoxic conditions resulted in preservation of high levels of organic matter in marine shales. Carbonate debris flows and turbiditic sandstones sourced from the adjacent uplifts are also common deposits in the Delaware Basin from this period. Subsequent burial and thermal maturation of this thick succession of Permian-aged strata containing high concentrations of preserved organic material resulted in what is widely recognized as one of the most prolific oil fields in the world.

The Delaware Basin encompasses an estimated 12,637 square miles and contained over 24,000 active producing wells as of the third quarter of 2016, with production from certain wells dating back to 1924. Beginning in 2010, horizontal drilling in the Delaware Basin has led a renaissance of development in this once over-looked basin. According to Baker Hughes, as of September 30, 2016, the Delaware Basin contains three of the top five most-active Permian Basin counties by horizontal rig count.

The vast majority of our acreage is located in the core of the Southern Delaware Basin, primarily in the adjacent Texas counties of Winkler, Ward, Reeves and Pecos. We divide our current areas of operation into three distinct projects: Cochise, Whiskey River and Big Tex. Cochise, where we have drilled and completed six operated wells, lies in the northern part of our acreage position and straddles Ward and Winkler Counties. Whiskey River, where we have drilled and completed eight operated wells, is in the central part of our overall leasehold position and is just west of the junction between Ward, Reeves and Pecos Counties. The Whiskey River project area also includes a leasehold block informally named County Line, which is in northern Pecos County, just south of the majority of the Whiskey River leasehold. The Big Tex project area, where we have drilled and completed two operated wells, is our southernmost leasehold position and lies in northern Pecos County.

We believe that our properties are prospective for oil and associated liquids-rich natural gas from multiple producing stratigraphic horizons. For the nine months ended September 30, 2016, our net daily production averaged 83% oil, 7% natural gas and 10% NGLs and had a greater liquids-content than other areas of the Delaware Basin.

Our horizontal drilling has been widespread with locations across the majority of our leasehold and includes 16 drilled and completed horizontal wells as of September 30, 2016. We have established commercial production in three distinct zones: Lower Wolfcamp A, Upper Wolfcamp A and Wolfcamp B. As a result, we have broadly appraised our acreage across all three project areas and several stratigraphic zones. Our successful drilling and completion of long-lateral wells has been a catalyst for activity from offset operators. We will closely monitor this offset activity, especially with respect to downspacing pilots, and adjust our future development plans accordingly to allow for the optimal development of our acreage position.

We operate approximately 98% of our net acreage and have an 89% average working interest in our acreage. This operational control gives us flexibility in development strategy and pace. We are currently operating three horizontal drilling rigs. In 2017, we expect our drilling program to grow to six horizontal rigs. During 2014 and 2015, we operated an average of one rig and placed five and seven horizontal wells on production, respectively. Our development drilling plan is comprised exclusively of horizontal drilling with an ongoing focus on reducing drilling times, optimizing completions and reducing costs. The average time from spud to rig release for our seven horizontal wells drilled during the nine months ended September 30, 2016 was approximately 42 days compared to an average of 67 days for the thirteen horizontal wells we drilled in 2015 and 2014. We expect that further optimization in the field (i.e. increased drilling of longer laterals, pad drilling, use of shared facilities and zipper fracs) will improve our well economics going forward.

The effective execution of completion design, target identification and refined geosteering are the predominant factors that dictate relative well performance in an area or zone. We have an evolving strategy that includes methodical adjustments of completion parameters, experimentation of different designs on wells with similar rock characteristics and constant monitoring and re-evaluation of results that ultimately tailor completions to the conditions specific to an area or zone. Our current completion method is a slickwater design utilizing predominantly 180 feet stage lengths, 30 foot cluster spacing, 85 barrels of total fluid per foot of lateral length and 2,500 to 3,500 pounds of varying sizes and types of sand per foot of lateral length. We expect that continued optimization in the field and our evolving completion strategy will both serve to further increase stockholder value.

Our drilling program is focused primarily on the Upper Wolfcamp A, Lower Wolfcamp A, Wolfcamp B and 3rd Bone Spring Sand. However, based on our well results and those of other operators, combined with our analysis of geologic and engineering data, we believe that significant additional development opportunities exist on our acreage in the Brushy Canyon, Avalon Shale, 1st Bone Spring Lime, 1st Bone Spring Sand, 2nd Bone Spring Sand, 3rd Bone Spring Lime and Wolfcamp C formations.

Ryder Scott, our independent petroleum engineering firm, has estimated that as of November 30, 2016, proved reserves net to our interest in our properties were approximately 32,680 MBoe, of which 40% were classified as proved developed. The proved reserves are generally characterized as long-lived, with predictable production profiles.

Production Status. For the nine months ended September 30, 2016, our average net daily production was 5,339 Boe/d (approximately 83% oil, 7% natural gas and 10% NGLs). During the nine months ended September 30, 2015, our average net daily production was 2,055 Boe/d (approximately 82% oil, 8% natural gas and 10% NGLs). As of September 30, 2016, we produced from 33 operated horizontal wells (16 of which we drilled and completed) and 14 operated vertical wells.

Recent and Future Activity. During the nine months ended September 30, 2016, 6.0 gross (5.9 net) wells were placed on production on our acreage. All of these wells were horizontal wells. We are currently operating three rigs in the Southern Delaware Basin and currently plan to add three additional rigs in 2017. During the fourth quarter of 2016, an additional five gross operated horizontal wells were placed on production.

As of September 30, 2016, we had identified 1,265 gross horizontal drilling locations on our acreage based on approximately 880-foot spacing in an offset pattern with five or six wells placed across a 5,280-foot wide drilling unit. If future downspacing pilots are successful, we estimate that we will add approximately 420 additional locations to our multi-year inventory through decreasing the horizontal lateral spacing, and may add further additional locations through decreasing the staggered vertical offset. Lateral length is dependent on the size of the drilling unit, with our current inventory consisting of laterals with an average length of 7,426 feet. In this prospectus, we define identified gross drilling locations as locations specifically identified and scheduled by management as an estimation of our multi-year drilling activities on existing acreage, based on an evaluation of applicable geologic and engineering data. We have estimated our horizontal drilling locations based on well spacing assumptions and upon the evaluation of our horizontal drilling results as well as those of other operators in our area, along with our interpretation of available geologic and engineering data. In particular, we have analyzed and interpreted open-hole logs, whole and sidewall core data, production data and drill cuttings that were acquired through drilling in connection with our horizontal drilling program. The horizontal locations for which we actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, operating costs, actual drilling results and other factors.

Oil and Natural Gas Data

Proved Reserves

Evaluation and Audit of Proved Reserves. Our proved reserve estimates as of November 30, 2016 and December 31, 2015 and 2014, were prepared by Ryder Scott, our independent petroleum engineers. The technical persons responsible for preparing our proved reserve estimates meet the requirements with regard to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Ryder Scott does not own an interest in any of our properties, nor is it employed by us on a contingent basis. A copy of Ryder Scott's proved reserve reports as of

November 30, 2016 and December 31, 2015 and 2014, are included as exhibits to the registration statement of which this prospectus forms a part.

We maintain an internal staff of petroleum engineers and geoscience professionals who worked closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves. Our internal technical team members meet with our independent reserve engineers periodically during the period covered by the proved reserve report to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to Ryder Scott for our properties, such as ownership interest, oil and natural gas production, well test data, commodity prices and operating and development costs. James T. Jaggers, our Senior Reservoir Engineer, is primarily responsible for overseeing the preparation of all of our reserve estimates. James T. Jaggers is a reservoir engineer with over 11 years of reservoir and operations experience, and has been licensed by the Texas Board of Professional Engineers since 2009. Our geoscience staff has an average of approximately 11 years of energy industry experience.

The preparation of our proved reserve estimates were completed in accordance with our internal control procedures. These procedures, which are intended to ensure reliability of reserve estimations, include the following:

- review and verification of historical production data, which data is based on actual production as reported by us;
- review of reserve estimates by James T. Jaggers or under his direct supervision;
- review by our Executive Vice President, Development Planning & Acquisitions of all of our reported proved reserves, including the review of all significant reserve changes and all new PUDs additions;
- direct reporting responsibilities by our Executive Vice President, Development Planning & Acquisitions to our Chief Executive Officer and President; and
- verification of property ownership by our land department.

Estimation of Proved Reserves. Under SEC rules, proved reserves are those quantities of oil and natural gas which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a "high degree of confidence that the quantities will be recovered". All of our proved reserves as of November 30, 2016, December 31, 2015 and December 31, 2014 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and natural gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions set forth by the SEC's regulations. The process of estimating the quantities of recoverable oil and natural gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into three broad categories or methods: (i) performance-based methods; (ii) volumetric-based methods; and (iii) analogy. These methods may be used individually or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Proved reserves for our properties were estimated by performance methods for the majority of properties. Certain new producing properties with inadequate historical production data were forecast using analogy or a combination of methods. Non-producing reserve estimates, for developed and undeveloped properties, were forecast using analogy methods.

To estimate economically recoverable proved oil and natural gas reserves and related future net cash flows, Ryder Scott considered many factors and assumptions including, but not limited to, the use of reservoir parameters derived from geological, geophysical and engineering data that cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates.

Under SEC rules, 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 have been field tested and have 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, the technologies and economic data used in the estimation of our proved reserves have been demonstrated to yield results with consistency and repeatability, and include production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, available seismic data and historical well cost and operating expense data.

Summary of Reserves. The following table presents our estimated net proved reserves as of November 30, 2016 and December 31, 2015 and 2014, based on the proved reserve report as of such dates by Ryder Scott, our independent petroleum engineering firm, prepared in accordance with the rules and regulations of the SEC. Copies of the proved reserve reports as of November 30, 2016 and December 31, 2015 and 2014, prepared by Ryder Scott with respect to our properties are included as exhibits to the registration statement of which this prospectus forms a part. All of our proved reserves are located in the United States.

	As of November 30, 2016(1)	As of December 31, 2015(2)	As of December 31, 2014(3)
Proved Developed Reserves:			
Oil (MBbls)	10,644	4,848	1,529
Natural gas (MMcf)	5,953	2,547	1,319
NGLs (MBbls)	1,338	621	288
Total (MBoe)(4)	12,974	5,894	2,037
Proved Undeveloped Reserves:			
Oil (MBbls)	15,727	5,645	389
Natural gas (MMcf)	9,337	3,610	310
NGLs (MBbls)	2,423	870	77
Total (MBoe)(4)	19,706	7,117	518
Total Proved Reserves:			
Oil (MBbls)	26,371	10,493	1,918
Natural gas (MMcf)	15,290	6,157	1,629
NGLs (MBbls)	3,761	1,491	365
Total (MBoe)(3)	32,680	13,011	2,555
Oil and Natural Gas Prices:			
Oil—WTI posted price per Bbl	$ 41.98	$ 50.28	$94.99
Natural gas—Henry Hub spot price per MMBtu	$ 2.39	$ 2.58	$ 4.35

(1) Our estimated net proved reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. For oil and NGL volumes, the average West Texas Intermediate posted price of $41.98 per barrel as of November 30, 2016, was adjusted for gravity, quality, local conditions, gathering, transportation fees and distance from market. For natural gas volumes, the average Henry Hub spot price of $2.39 per MMBtu as of November 30, 2016, was similarly adjusted for gravity, quality, local conditions, gathering, transportation fees and distance from market. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $38.62 per barrel of oil, $14.70 per barrel of NGL and $2.18 per Mcf of natural gas as of November 30, 2016.

(2) Our estimated net proved reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. For oil and NGL volumes, the average West Texas Intermediate posted price of $50.28 per barrel as of December 31, 2015, was adjusted for gravity, quality, local conditions, gathering, transportation fees and distance from market. For natural gas volumes, the average Henry Hub spot price of $2.58 per MMBtu as of December 31, 2015, was similarly adjusted for gravity, quality, local conditions, gathering, transportation fees and distance from market. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $46.26 per barrel of oil, $16.49 per barrel of NGL and $2.36 per Mcf of natural gas as of December 31, 2015.

(3) Our estimated net proved reserves were determined using average first-day-of-the-month prices for the prior 12 months in accordance with SEC guidance. For oil and NGL volumes, the average West Texas Intermediate posted price of $94.99 per barrel as of December 31, 2014, was adjusted for gravity, quality, local conditions, gathering, transportation fees and distance from market. For natural gas volumes, the average Henry Hub spot price of $4.35 per MMBtu as of December 31, 2014, was similarly adjusted for was adjusted for gravity, quality, local conditions, gathering, transportation fees and distance from market. All prices are held constant throughout the lives of the properties. The average adjusted product prices weighted by production over the remaining lives of the properties are $84.54 per barrel of oil, $31.17 per barrel of NGL and $4.21 per Mcf of natural gas as of December 31, 2014.

(4) Totals may not sum or recalculate due to rounding.

Estimated proved reserves at November 30, 2016 were 32.7 MMBoe, compared to 13.0 MMBoe and 2.6 MMBoe at December 31, 2015 and 2014, respectively. The increases in proved reserves during the eleven months ended November 30, 2016 and the year ended December 31, 2015 were primarily related to drilling activities. During the eleven months ended November 30, 2016, we drilled and completed nine wells and added 20 PUD locations. We also drilled and were in the process of completing two additional wells. This activity resulted in a combined increase of 19.9 MMBoe through extensions and discoveries. We acquired two wells and an additional 25% working interest in another section, which added a combined 0.6 MMBoe. Over this time period we've also had approximately 1.0 MMBoe of upward revisions to prior forecasts due to increased performance from our wells, despite negative impacts from the decline in average oil and natural gas pricing between periods. During the year ended December 31, 2015, we drilled and completed seven wells and added nine PUD locations, leading to a combined increase of 10.8 MMBoe through extensions and discoveries. We also had 0.6 MMBoe of upward revisions of prior reserve estimates due to increased performance from our wells, partially offset by negative impacts from the decline in average oil and natural gas pricing between periods.

Reserve engineering is and must be recognized as a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered. Estimates of economically recoverable oil and natural gas and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs. Please read "Risk Factors" appearing elsewhere in this prospectus.

Additional information regarding our proved reserves can be found in the notes to our financial statements included elsewhere in this prospectus and the proved reserve reports as of November 30, 2016 and December 31, 2015 and 2014, which are included as exhibits to the registration statement of which this prospectus forms a part.

PUDs

As of December 31, 2014, we had one PUD location totaling 389 MBbls of oil, 310 MMcf of natural gas and 77 MBbls of NGLs, for a total of 518 MBoe. As of December 31, 2015, our PUDs totaled 5,645 MBbls of oil, 3,610 MMcf of natural gas and 870 MBbls of NGLs, for a total of 7,117 MBoe. As of November 30, 2016, our PUDs totaled 15,727 MBbls of oil, 9,337 MMcf of natural gas and 2,423 MBbls of NGLs, for a total of 19,706 MBoe. PUDs will be converted from undeveloped to developed as the applicable wells are drilled and completed and begin production.

Of the 6,599 MBoe of PUDs we added during 2015, 1,656 MBoe resulted from improved production from two wells we completed in the last four months of 2014. This additional production history led to an increase in the reserves of our PUD location booked in 2014 as well as two additional PUD locations offsetting a well that came on production in December 2014. Our increase in PUD reserves in 2015 also included seven new PUD locations, totaling 4,943 MBoe, added as a result of offset drilling during 2015.

We saw a net increase of 12,589 MBoe in PUD reserves during the eleven months ended November 30, 2016. The increase in PUD reserves during these eleven months included 20 new PUD locations, totaling 15,108 MBoe, that were added as a result of offset drilling during this time period. Of the ten PUD locations that we had booked at December 31, 2015, four have been developed and the remaining six are still carried as PUDs. Reserves booked to these six PUDs have increased by 517 MBoe. An additional 25% working interest in one of the sections resulted in 198 MBoe of that increase, while the remaining 319 MBoe increase was as a result of upward revisions due to increased performance in surrounding wells.

We do not plan to begin drilling efforts on our December 31, 2014 PUD location until 2017. Therefore, during the twelve months ended December 31, 2015, we incurred no expenses converting PUDs to proved developed reserves. During the eleven months ended November 30, 2016, however, we incurred $44.1 million of expenses converting four of our December 31, 2015 PUD locations to proved developed producing.

All of our PUD drilling locations are scheduled to be drilled within five years of their initial booking. As of November 30, 2016, 1,565 MBoe of our total proved reserves were classified as PDNP.

Oil and Natural Gas Production Prices and Costs

Production and Price History

The following table sets forth information regarding net production of oil, natural gas and NGLs and certain price and cost information for each of the periods indicated:

	Nine Months Ended September 30,		Year Ended December 31,	
	2016	2015	2015	2014
Production:				
Oil (MBbls)	1,210	459	718	189
Natural gas (MMcf)	669	269	404	172
NGLs (MMBbls)	141	57	89	35
Total (MBoe)(1)	1,463	561	874	253
Average sales price:				
Oil (per Bbl)	$39.02	$46.72	$43.92	$77.28
Natural gas (per Mcf)	2.17	2.57	2.35	3.76
NGLs (per Bbl)	14.35	14.88	14.93	29.40
Total (per Boe)	$34.65	$40.97	$38.69	$64.35
Average sales price after impact of cash-settled derivatives:				
Oil (per Bbl)	$38.06	$55.71	$52.19	$81.32
Natural gas (per Mcf)	2.17	2.57	2.35	3.76
NGLs (per Bbl)	14.35	14.88	14.93	29.40
Total (per Boe)	$33.85	$48.33	$45.48	$67.37
Operating expenses per Boe:				
Lease operating expenses	$ 3.57	$ 4.20	$ 3.62	$ 8.07
Gathering and transportation expenses	0.45	0.17	0.20	0.48
Production and ad valorem taxes	2.17	2.83	2.57	3.64
Depletion, depreciation, amortization and accretion	20.12	25.83	25.94	33.38
Impairment of oil and natural gas properties and dry hole costs	1.03	0.01	7.42	5.58
Other operating expenses	1.14	0.46	0.30	0.25
General and administrative(2)	5.38	10.53	8.52	28.97
Total operating expenses per Boe	$33.86	$44.03	$48.57	$80.37

(1) Total may not sum or recalculate due to rounding.

(2) General and administrative does not include additional expenses we would have to incur as a result of being a public company.

Productive Wells

As of September 30, 2016, we owned a 98% average working interest in 46 gross (44.9 net) productive wells. Our wells are oil wells that produce associated liquids-rich natural gas. Productive wells consist of producing wells, wells capable of production and wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest, operated and non-operated, and net wells are the sum of our fractional working interests owned in gross wells.

Developed and Undeveloped Acreage

The following table sets forth information as of September 30, 2016, relating to our leasehold acreage. Developed acreage consists of acres spaced or assigned to productive wells and does not include undrilled acreage held by production under the terms of the lease. Undeveloped acreage is defined as acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

Developed Acreage		Undeveloped Acreage		Total Acreage	
Gross(1)	Net(2)	Gross(1)	Net(2)	Gross(1)	Net(2)
3,905	3,783	64,216	57,092	68,121	60,875

(1) A gross acre is an acre in which a working interest is owned. The number of gross acres is the total number of acres in which a working interest is owned.

(2) A net acre is deemed to exist when the sum of the fractional ownership working interests in gross acres equals one. The number of net acres is the sum of the fractional working interests owned in gross acres expressed as whole numbers and fractions thereof.

Many of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production. Substantially all of the leases governing our acreage have continuous development clauses that permit us to continue to hold the acreage under such leases after the expiration of the primary term if we initiate additional development within 120 to 180 days after the completion of the last well drilled on such lease, without the requirement of a lease extension payment. Thereafter, the lease is held with additional development every 120 to 180 days until the entire lease is held by production. None of our horizontal drilling locations associated with proved undeveloped reserves are scheduled for drilling outside of a lease term that is not accounted for with a continuous development schedule or primary term. The following table sets forth the net undeveloped acreage that, as of September 30, 2016, was subject to expiration over the succeeding five years unless production was established within the spacing units covering the acreage or the lease was renewed or extended under continuous drilling provisions prior to the primary term expiration dates.

Q4 2016	2017	2018	2019	2020
249	12,346	9,131	8,354	8,216

Based on our current development plans, we expect to maintain substantially all of the acreage that would otherwise expire during 2016 and 2017 either through drilling and establishing production or making lease extension payments. Given our currently planned drilling activities, we do not expect the amount of any such lease extension payments to be material. Further, based on our current development plans, we expect that substantially all of our acreage will be held by production by the fourth quarter of 2018 or the first quarter of 2019.

Drilling Results

The following table sets forth the results of our drilling activity, as defined by wells having been placed on production, for the periods indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation among the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce, or are capable of producing, commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return. Dry wells are those that prove to be incapable of producing hydrocarbons in sufficient quantities to justify completion.

	For the Nine Months Ended September 30,				For the Year Ended December 31,			
	2016		2015		2015		2014	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:								
Productive(1)	—	—	—	—	—	—	—	—
Dry(2)	—	—	—	—	1.0	1.0	—	—
Total Exploratory	—	—	—	—	1.0	1.0	—	—
Development Wells:								
Productive(1)	6.0	5.9	5.0	4.9	7.0	6.4	5.0	4.8
Dry(3)	—	—	—	—	—	—	—	—
Total Development	6.0	5.9	5.0	4.9	7.0	6.4	5.0	4.8
Total Wells:								
Productive(1)	6.0	5.9	5.0	4.9	7.0	6.4	5.0	4.8
Dry	—	—	—	—	1.0	1.0	—	—
Total	6.0	5.9	5.0	4.9	8.0	7.4	5.0	4.8

(1) Although a well may be classified as productive upon completion, future changes in oil and natural gas prices, operating costs and production may result in the well becoming uneconomical, particularly exploratory wells where there is no production history.

(2) Relates to a vertical test well drilled to an unproductive shallow horizon.

(3) Does not include a wellbore temporarily abandoned due to mechanical failure.

Operations

General

We are the operator of approximately 98% of our net acreage. As operator, we design and manage the development of our wells and supervise operation and maintenance activities on a day-to-day basis. Independent contractors engaged by us provide all the equipment and personnel associated with these activities. We employ petroleum engineers, geologists and land professionals who work to improve production rates, increase reserves, acquire properties, obtain permitting and lower the cost of operating our oil and natural gas properties.

Transportation and Marketing

We are party to a long-term gathering agreement entered into in 2015 pursuant to which we have dedicated all of our oil production from our Whiskey River and Cochise acreage. We sell substantially all of our oil production from our Whiskey River and Cochise acreage pursuant to a short-term marketing agreement. We sell substantially all of our natural gas from our Cochise acreage under a long-term gathering and processing agreement entered into in September 2015, and substantially all of our natural gas from our Whiskey River and Big Tex acreage pursuant to a gathering and processing agreement expiring in the fall of 2017, with substantially all of such natural gas transported from the wellhead by third-party gathering lines to natural gas processing facilities. None of our sales and transportation agreements contain minimum volume commitments or other similar provisions.

In October 2016, we entered into a long-term natural gas gathering and processing agreement for our Whiskey River acreage. We expect to begin selling natural gas under this agreement in early 2017.

Customers

We sell our oil, natural gas and NGL production to purchasers at market prices. We sell our production to a relatively small number of customers, as is customary in our business. For the nine months ended September 30, 2016, two purchasers accounted for more than 10% of our revenue: Trafigura Trading, LLC (47%) and Sunoco Partners Marketing (40%). For the year ended December 31, 2015, two purchasers accounted for more than 10% of our revenue: Sunoco Partners Marketing (68%) and Shell Trading (21%). For the year ended December 31, 2014, two purchasers accounted for more than 10% of our revenue: Shell Trading (72%) and Plains Marketing, LP (15%). During such periods, no other purchaser accounted for 10% or more of our revenue. The loss of any of these purchasers could materially and adversely affect our revenues in the short-term. However, based on the current demand for oil and natural gas and the availability of other purchasers, we believe that the loss of any of our purchasers would not have a long-term material adverse effect on our financial condition and results of operations because crude oil and natural gas are fungible products with well-established markets.

Infrastructure

Our infrastructure strategy includes owning sufficient tracts of surface acreage to (i) allow us to control fresh water supply for drilling and completions, (ii) provide ease of pipeline installation, (iii) allow construction of storage for both fresh and produced water and (iv) simplify construction of facilities for disposal of flowback and produced water. In addition, we have supplemental agreements that provide for fresh water sourcing and produced water storage and disposal services from adjacent landowners. As of September 30, 2016, our installed and contracted capacities were (i) 4.7 million barrels of water storage capacity, (ii) 10.5 miles of fresh water pipelines and 63.6 miles of produced water transportation pipelines, which allows us to largely eliminate water trucking in all phases of our operation, (iii) 162 thousand barrels per day of water sourcing capacity and (iv) 86 thousand barrels per day of water disposal capacity. Accordingly, we have disposal capacity more than three times our current produced water volumes and sufficient sources of fresh water to support our current drilling program and we believe it is scalable to support additional rigs. This infrastructure position provides important cost advantages compared to utilizing third-party services.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies that have greater resources. Many of these companies not only explore for and produce oil and natural gas, but also carry on midstream and refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or to define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Our larger or more integrated competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties.

There is also competition between oil and natural gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the governments of the United States and the jurisdictions in which we operate. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of developing oil and natural gas and may prevent or delay the commencement or continuation of a given operation. Our larger competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position.

Seasonality of Business

Weather conditions affect the demand for, and prices of, oil and natural gas. Demand for oil and natural gas is typically higher in the fourth and first quarters resulting in higher prices. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis.

Title to Properties

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties in connection with acquisition of leasehold acreage. At such time as we determine to conduct drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects prior to commencement of drilling operations. 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 have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry.

Prior to completing an acquisition of producing oil and natural gas leases, we perform title reviews on the most significant leases and, depending on the materiality of properties, we may obtain a title opinion, obtain an updated title review or opinion or review previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens for current taxes and other burdens which we believe do not materially interfere with the use of or affect our carrying value of the properties.

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 prospectus.

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 22.5% to 25.0%, resulting in a net revenue interest to us generally ranging from 75.0% to 77.5%.

Regulation of the Oil and Natural Gas Industry

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 development 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 crude oil or natural gas 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.

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, the states, the FERC and the courts. We cannot predict when or whether any such proposals may become effective. We do not believe that we would be affected by any such action materially differently than similarly situated competitors.

We believe we are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered.

Regulation of Production of Oil and Natural Gas

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. We own interests in properties located in Texas, which regulates drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The laws of Texas also govern a number of conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing or density and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing or density. Moreover, Texas imposes a production or severance tax with respect to the production and sale of oil, natural gas and NGLs within its jurisdiction. We do not believe that we are impacted any differently by these regulations than similarly situated competitors.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Regulation of Sales and Transportation of Oil

Sales of oil, condensate and NGLs are not currently regulated and are made at negotiated prices. Although prices of these energy commodities are currently unregulated, the United States Congress historically has been active in their regulation. We cannot predict whether new legislation to regulate oil and NGLs, or the prices charged for these commodities might be proposed, what proposals, if any, might actually be enacted by the United States Congress or the various state legislatures and what effect, if any, the proposals might have on the our operations. Additionally, such sales may be subject to certain state, and potentially federal, reporting requirement.

Our sales of oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate and access regulation. The FERC regulates interstate transportation of oil, including natural gas liquids, under the Interstate Commerce Act ("ICA"). Prices received from the sale of oil liquids may be affected by the cost of transporting those products to market. The ICA requires that pipelines maintain a tariff on file with FERC. The tariff sets forth the established rates as well as the rules and regulations governing the service. The ICA requires, among other things, that rates and terms and conditions of service on interstate common carrier pipelines be "just and reasonable". In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market based rates may be permitted in certain circumstances. Such pipelines must also provide jurisdictional service in a manner that is not unduly discriminatory or unduly preferential. Shippers have the power to challenge new and existing rates and terms and conditions of service before FERC.

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates and regulations regarding access are equally applicable to all comparable shippers, we believe that the regulation of oil transportation will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Regulation of Transportation and Sales of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily FERC. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the NGPA, and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed controls affecting wellhead sales of natural gas effective January 1, 1993. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the NGA, and by regulations and orders promulgated under the NGA by FERC. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations.

The EP Act of 2005 is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, the EP Act of 2005 amends the NGA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. The EP Act of 2005 provides FERC with the power to assess civil penalties of up to $1,000,000 per day for violations of the NGA and increases FERC's civil penalty authority under the NGPA from $5,000 per violation per day to $1,000,000 per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-market manipulation provision of the EP Act of 2005, and subsequently denied rehearing. The rules make it unlawful to: (i) in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; (ii) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (iii) to engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of natural gas pipelines and storage companies that provide interstate services, as well as otherwise non-jurisdictional entities to the extent the activities are conducted "in connection with" natural gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order 704, described below. The anti-market manipulation rule and enhanced civil penalty authority reflect an expansion of FERC's NGA enforcement authority.

On December 26, 2007, FERC issued Order 704, a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing. Under Order 704, any market participant that engages in wholesale sales or purchases of natural gas that equal or exceed 2.2 million MMBtus of physical natural gas in the previous calendar year, including natural gas producers, gatherers and marketers, are required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices to FERC on Form No. 552. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with FERC's policy statement on price reporting.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. Although FERC has set forth a general test for determining whether facilities perform a non-jurisdictional gathering function or a jurisdictional transmission function, FERC's determinations as to the classification of facilities are done on a case by case basis. To the extent that FERC issues an order that reclassifies certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, and depending on the scope of that decision, our costs of getting natural gas to point of sale locations may increase. We believe that the natural gas pipelines in the gathering systems we use meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of ongoing litigation, so the classification and regulation of the gathering facilities we use are subject to change based on future determinations by FERC, the courts or Congress. State regulation of natural gas gathering facilities generally includes various occupational safety, environmental and, in some circumstances, nondiscriminatory-take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

The price at which we sell natural gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical sales of these energy commodities, we are required to observe anti-market manipulation laws and related regulations enforced by FERC under the EP Act of 2005 and under the Commodity Exchange Act ("CEA"), and regulations promulgated thereunder by the CFTC. The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third-party damage claims by, among others, sellers, royalty owners and taxing authorities.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Changes in law and to FERC or state policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate and intrastate pipelines, and we cannot predict what future action FERC or state regulatory bodies will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers and marketers with which we compete.

Regulation of Environmental and Occupational Safety and Health Matters

Our oil and natural gas development operations are subject to numerous stringent federal, regional, state and local statutes and regulations governing occupational safety and health, the discharge of materials into the environment or otherwise relating to environmental protection, some of which carry substantial administrative, civil and criminal penalties for failure to comply. These laws and regulations may require the acquisition of a permit before drilling or other regulated activity commences; restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines; govern the sourcing and disposal of water used in the drilling and completion process; limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier and other protected areas; require some form of remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits; establish specific safety and health criteria addressing worker protection; and impose substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of production.

The following is a summary of the more significant existing environmental and occupational health and safety laws and regulations, as amended from time to time, to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous Substances and Waste Handling

The Comprehensive Environmental Response, Compensation, and Liability Act of 1980 (“CERCLA”), also known as the “Superfund” law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a “hazardous substance” into the environment. These persons include the current and past owner or operator of the disposal site or the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances at the site where the release occurred. 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 and for damages to natural resources, and 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. We are able to control directly the operation of only those wells with respect to which we act as operator. Notwithstanding our lack of direct control over wells operated by others, the failure of an operator other than us to comply with applicable environmental regulations may, in certain circumstances, be attributed to us and result in CERCLA liability.

The Resource Conservation and Recovery Act ("RCRA") and analogous state laws, impose detailed requirements for the generation, handling, storage, treatment and disposal of nonhazardous and hazardous solid wastes. RCRA specifically excludes drilling fluids, produced waters and other wastes associated with the development or production of crude oil, natural gas or geothermal energy from regulation as hazardous wastes. However, these wastes may be regulated by the EPA or state agencies under RCRA's less stringent nonhazardous solid waste provisions, state laws or other federal laws. Moreover, it is possible that these particular oil and natural gas development and production wastes now classified as nonhazardous solid wastes could be classified as hazardous wastes in the future. For example, in December 2016, the EPA and environmental groups entered into a consent decree to address EPA's alleged failure to timely assess RCRA Subtitle D criteria regulations exempting certain exploration and production related oil and gas wastes from regulation as hazardous wastes under RCRA. The consent decree requires EPA to propose a rulemaking no later than March 15, 2019 for revision of the Subtitle D criteria regulations pertaining to oil and gas wastes or to sign a determination that revision of the regulations is not necessary. A loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in an increase in our costs to manage and dispose of generated wastes, which could have a material adverse effect on our results of operations and financial position. In addition, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils that may be regulated as hazardous wastes if such wastes have hazardous characteristics.

We currently own, lease or operate numerous properties that have been used for oil and natural gas development and production activities for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or petroleum hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off-site locations, where such substances have been taken for recycling or disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or petroleum hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to undertake response or corrective measures, which could include removal of previously disposed substances and wastes, cleanup of contaminated property or performance of remedial plugging or pit closure operations to prevent future contamination.

Water Discharges

The Clean Water Act and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and natural gas wastes, into or near navigable waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers (the "Corps"). In September 2015, the EPA and the Corps issued new rules defining the scope of the EPA's and the Corps' jurisdiction under the Clean Water Act with respect to certain types of waterbodies and classifying these waterbodies as regulated wetlands. To the extent the rule expands the scope of the Clean Water Act's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. The rule has been challenged in court on the grounds that it unlawfully expands the reach of the Clean Water Act, and implementation of the rule has been stayed pending resolution of the court challenge. Obtaining permits has the potential to delay the development of oil and natural gas projects. These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages.

Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as "SPCC plans", in connection with on-site storage of significant quantities of oil. We are currently undertaking a review of our properties to determine the need for new or updated SPCC plans and, where necessary, we will be developing or upgrading such plans implementing the physical and operation controls imposed by these plans, the costs of which are not expected to be substantial.

The primary federal law related specifically to oil spill liability is the Oil Pollution Act of 1990 ("OPA"), which amends and augments the 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 waters of the United States or adjoining shorelines. For example, operators of certain oil and natural gas facilities must develop, implement and maintain facility response plans, conduct annual spill training for certain employees and provide varying degrees of financial assurance. Owners or operators of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge is one type of "responsible party" who is liable. The OPA applies 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, they are limited. As such, a violation of the OPA has the potential to adversely affect our operations.

Air Emissions

The federal Clean Air Act and comparable state laws restrict the emission of air pollutants from many sources, such as compressor stations, through air emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. These laws and regulations may require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in October 2015, the EPA lowered the National Ambient Air Quality Standard ("NAAQS") for ozone from 75 to 70 parts per billion. State implementation of the revised NAAQS could result in stricter permitting requirements, delay or prohibit our ability to obtain such permits and result in increased expenditures for pollution control equipment, the costs of which could be significant. In addition, the EPA has adopted new rules under the Clean Air Act that require the reduction of volatile organic compound emissions from certain fractured and refractured natural gas wells for which well completion operations are conducted and further require that most wells use reduced emission completions, also known as "green completions". These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors and from pneumatic controllers and storage vessels. More recently, in May 2016, the EPA finalized rules regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and natural gas industry. 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. See also "—Regulation of GHG Emissions". Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of oil and natural gas projects and increase our costs of development, which costs could be significant.

Regulation of GHG Emissions

In response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment, the EPA has adopted regulations pursuant to the federal Clean Air Act that, among other things, require preconstruction and operating permits for certain large stationary sources. Facilities required to obtain preconstruction permits for their GHG emissions are also required to meet "best available control technology" standards that are being established by the states or, in some cases, by the EPA on a case-by-case basis. These regulatory requirements could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and natural gas production sources in the United States on an annual basis, which include certain of our operations. Furthermore, in May 2016, the EPA finalized rules that establish new controls for emissions of methane from new, modified or reconstructed sources in the oil and natural gas source category, including production, processing, transmission and storage activities. The rules include first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions. In addition, the rules impose leak detection and repair requirements intended to address methane leaks known as "fugitive emissions" from equipment, such as valves, connectors, open-ended lines, pressure-relief devices, compressors, instruments and meters. The EPA has also announced that it intends to impose methane emission standards for existing sources as well but, to date, has not yet issued a proposal. Compliance with these rules will require enhanced record-keeping practices, the purchase of new equipment such as optical gas imaging instruments to detect leaks and increased frequency of maintenance and repair activities to address emissions leakage. The rules will also likely require hiring additional personnel to support these activities or the engagement of third party contractors to assist with and verify compliance. The BLM also finalized similar rules regarding the control of methane emissions in November 2016 that apply to oil and natural gas exploration and development activities on public and tribal lands. The rules seek to minimize venting and flaring of emissions from storage tanks and other equipment, and also impose leak detection and repair requirements. These new and proposed rules could result in increased compliance costs on our operations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant legislative activity at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs. These programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs.

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. Demand for our products may also be adversely affected by conservation plans and efforts undertaken in response to global climate change, including plans developed in connection with the recent Paris climate conference in December 2015, which the U.S. ratified in September 2016. Many governments also provide, or may in the future provide, tax advantages and other subsidies to support the use and development of alternative energy technologies. Substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce and lower the value of our reserves.

Finally, increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events; if any such effects were to occur, they could have a material adverse effect on our operations. At this time, we have not developed a comprehensive plan to address the legal, economic, social or physical impacts of climate change on our operations.

Hydraulic Fracturing Activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of oil and/or natural gas from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, proppants and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Hydraulic fracturing is typically regulated by state oil and natural gas commissions, but federal agencies have asserted jurisdiction over certain aspects of the process. The EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities using diesel fuels. The EPA has also taken the following actions: issued final regulations under the federal Clean Air Act establishing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; issued an advanced notice of proposed rulemaking under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing; and, in June 2016, published an effluent limitation guideline final rule prohibiting the discharge of wastewater from onshore unconventional oil and natural gas extraction facilities to publicly owned wastewater treatment plants. In addition, the Bureau of Land Management finalized rules in March 2015 that impose new or more stringent standards for performing hydraulic fracturing on federal and American Indian lands. The U.S. District Court of Wyoming struck down the final rule, finding that the BLM lacked congressional authority to promulgate the rule. The BLM has appealed this decision, and a final decision remains pending. In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. It is unclear how any additional federal regulation of hydraulic fracturing activities may affect our operations.

Certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. For example, in December 2016, the EPA released its final report on the potential impacts of hydraulic fracturing on drinking water resources. The final report concluded that "water cycle" activities associated with hydraulic fracturing may impact drinking water resources "under some circumstances", noting that the following hydraulic fracturing water cycle activities and local- or regional-scale factors are more likely than others to result in more frequent or more severe impacts: water withdrawals for fracturing in times or areas of low water availability; surface spills during the management of fracturing fluids, chemicals or produced water; injection of fracturing fluids into wells with inadequate mechanical integrity; injection of fracturing fluids directly into groundwater resources; discharge of inadequately treated fracturing wastewater to surface waters; and disposal or storage of fracturing wastewater in unlined pits. Since the report did not find a direct link between hydraulic fracturing itself and contamination of groundwater resources, this years-long study report does not appear to provide any basis for further regulation of hydraulic fracturing at the federal level. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing under the federal SDWA or other regulatory mechanisms.

At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing activities. For example, in May 2013, the Railroad Commission of Texas issued a "well integrity rule", which updates the requirements for drilling, putting pipe down and cementing wells. The rule also includes new testing and reporting requirements, such as (i) the requirement to submit cementing reports after well completion or after cessation of drilling, whichever is later, and (ii) the imposition of additional testing on wells less than 1,000 feet below usable groundwater. The well integrity rule took effect in January 2014. Local governments also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of development activities and perhaps even be precluded from drilling wells.

ESA and Migratory Birds

The Endangered Species Act ("ESA") and (in some cases) comparable state laws were established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We may conduct operations on oil and natural gas leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species, such as the sage grouse, that potentially could be listed as threatened or endangered under the ESA may exist. The U.S. Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for oil and natural gas development. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing of more than 250 species as endangered or threatened under the ESA by no later than completion of the agency's 2017 fiscal year. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The federal government recently issued indictments under the Migratory Bird Treaty Act to several oil and natural gas companies after dead migratory birds were found near reserve pits associated with drilling activities. The identification or designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our development activities that could have an adverse impact on our ability to develop and produce reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

OSHA

We are subject to the requirements of the Occupational Safety and Health Act ("OSHA") and comparable state statutes whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the Emergency Planning and Community Right-to-Know Act and comparable state statutes and any implementing regulations 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 governmental authorities and citizens.

Related Permits and Authorizations

Many environmental laws require us to obtain permits or other authorizations from state and/or federal agencies before initiating certain drilling, construction, production, operation or other oil and natural gas activities, and to maintain these permits and compliance with their requirements for on-going operations. These permits are generally subject to protest, appeal or litigation, which can in certain cases delay or halt projects and cease production or operation of wells, pipelines and other operations.

We have not experienced any material adverse effect from compliance with environmental requirements; however, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2016, nor do we anticipate that such expenditures will be material in 2017 or 2018.

Related Insurance

We maintain insurance against some risks associated with above or underground contamination that may occur as a result of our development activities. However, this insurance is limited to activities at the well site and there can be no assurance that this insurance will continue to be commercially available or that this insurance will be available at premium levels that justify its purchase by us. The occurrence of a significant event that is not fully insured or indemnified against could have a materially adverse effect on our financial condition and operations. Further, we have no coverage for gradual, long-term pollution events.

Employees

As of September 30, 2016, we had 30 full-time employees. We hire independent contractors on an as needed basis. We have no collective bargaining agreements with our employees. We believe that our employee relationships are satisfactory.

Legal Proceedings

We are party to lawsuits arising in the ordinary course of our business. We cannot predict the outcome of any such lawsuits with certainty, but management believes it is remote that pending or threatened legal matters will have a material adverse impact on our financial condition.

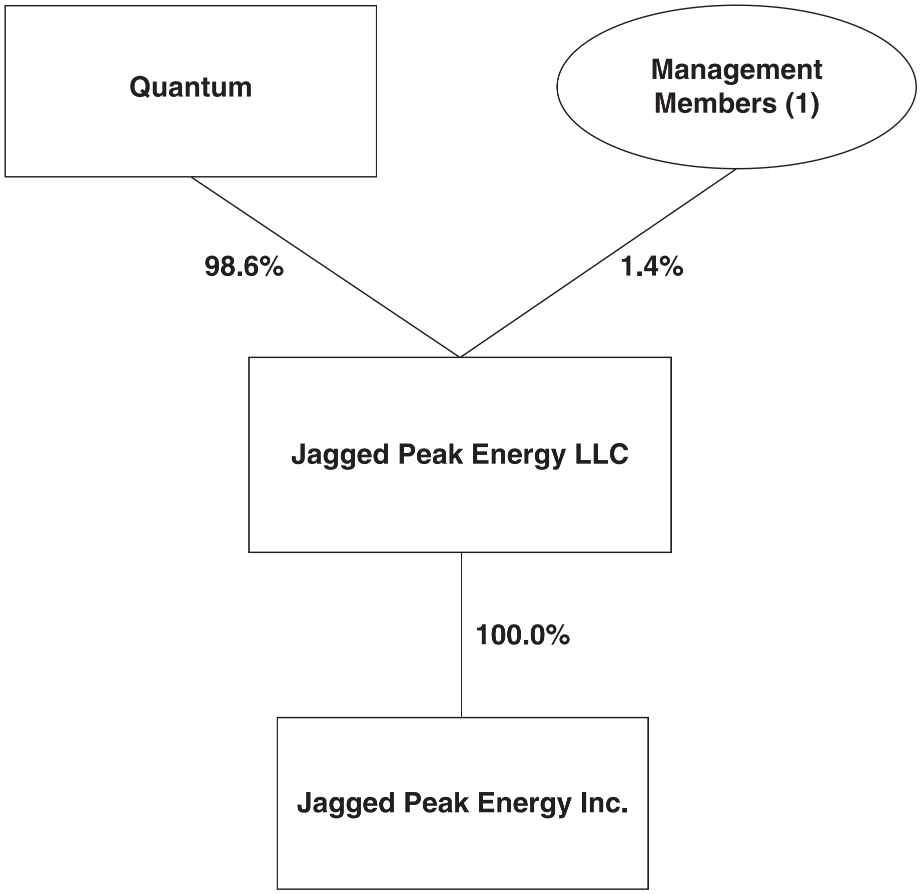
Due to the nature of our business, we are, from time to time, involved in other routine litigation or subject to disputes or claims related to our business activities, including workers' compensation claims and employment related disputes. In the opinion of our management, none of these other pending litigation, disputes or claims against us, if decided adversely, will have a material adverse effect on our financial condition, cash flows or results of operations.

CORPORATE REORGANIZATION

We have incorporated under the laws of the State of Delaware to become a holding company for Jagged Peak Energy LLC and its assets and operations. Jagged Peak Energy LLC, which is our accounting predecessor, was formed as a Delaware limited liability company in 2013 with equity commitments from Quantum and certain of our Management Members. The Management Members also hold management incentive units in Jagged Peak Energy LLC that entitle the holders thereof to a portion of any proceeds distributed by Jagged Peak Energy LLC following the achievement of certain return thresholds by the capital interest owners of Jagged Peak Energy LLC.

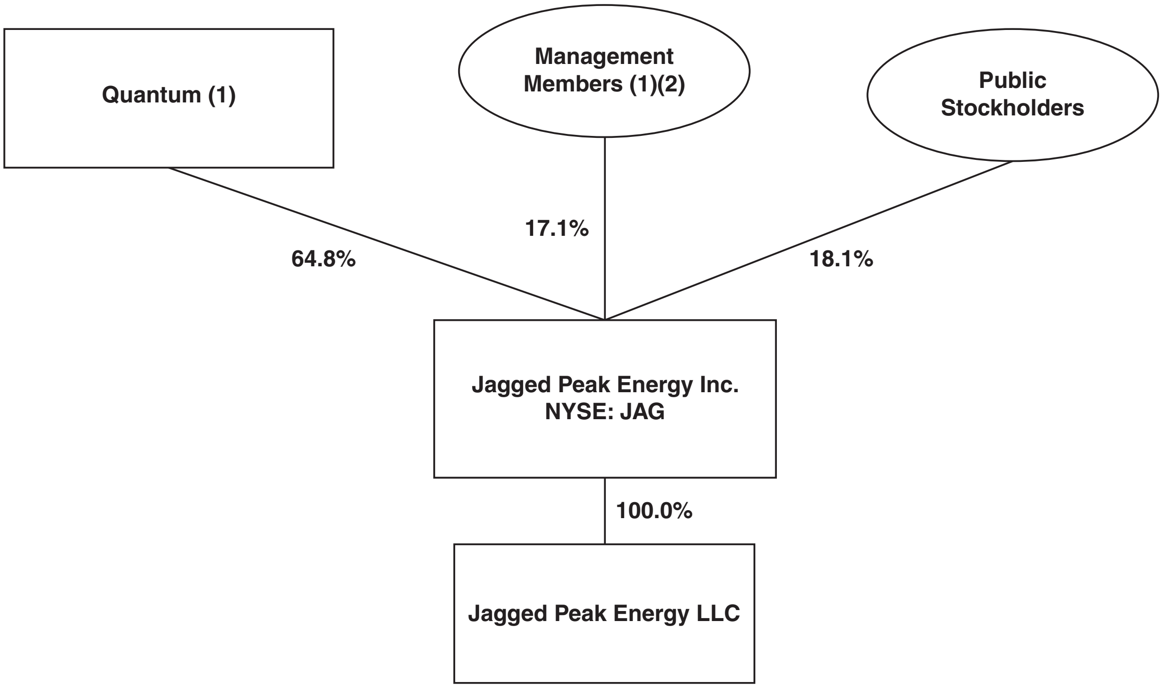
Pursuant to the terms of certain reorganization transactions that will be completed immediately prior to the closing of this offering, (i) the equity interests (both capital interests and management incentive units) in Jagged Peak Energy LLC will be recapitalized into a single class of units ("Units"), with the Units to be allocated among the Existing Owners in accordance with the terms of the limited liability company agreement of Jagged Peak Energy LLC and calculated using an implied valuation for Jagged Peak Energy LLC based on the initial public offering price of our common stock, (ii) our officers and other employees that hold management incentive units in Jagged Peak Energy LLC will contribute to Management Holdco certain of the Units issued to them in the recapitalization described above in exchange for membership interests in Management Holdco and (iii) Jagged Peak Energy LLC will merge into a subsidiary of Jagged Peak Energy Inc., and the Existing Owners and Management Holdco will receive as consideration in the merger shares of Jagged Peak Energy Inc. common stock, with such shares of common stock to be allocated among the Existing Owners and Management Holdco pro rata based on their relative ownership of Units. As a result of these transactions, Jagged Peak Energy LLC will become a wholly owned subsidiary of Jagged Peak Energy Inc. The membership interests in Management Holdco that will be issued to our officers and other employees that hold management incentive units in Jagged Peak Energy LLC in exchange for their Units will generally vest in equal installments on each of the first three anniversaries of this offering, subject to continued employment and other conditions, and will be settled in shares of our common stock upon vesting.

The following diagram indicates the current simplified ownership structure of Jagged Peak Energy LLC.



(1) Does not include management incentive units. See "—Existing Owners' Ownership".

The following diagram indicates our simplified ownership structure after giving effect to our corporate reorganization and this offering (assuming that the underwriters' option to purchase additional shares is not exercised).



(1) Assumes an initial offering price of $17.00 per share of common stock, the midpoint of the price range set forth on the cover page of this prospectus. Any increase or decrease (as applicable) of the assumed initial public offering price will result in an increase or decrease, respectively, in the number of shares of common stock to be received by the Management Members and Management Holdco, and an equivalent decrease or increase, respectively, in the number of shares of common stock to be received by Quantum. Accordingly, any such change in our initial public offering price will not affect the aggregate number of shares of common stock held by our Existing Owners. See "Corporate Reorganization—Existing Owners' Ownership".

(2) Includes shares of common stock held by the Management Members and shares of common stock held by Management Holdco. Includes aggregate ownership by the Management Members that currently serve as our officers and other employees of approximately 10.8% of our common stock.

Existing Owners' Ownership

The table below sets forth the percentage ownership of our Existing Owners prior to this offering and after the consummation of this offering (assuming that the underwriters' option to purchase additional shares is not exercised).

Existing Owners(1)	Percentage Ownership in Jagged Peak Energy LLC Prior to this Offering(2)	Equity Interests in Jagged Peak Energy Inc. Following this Offering	
		Common Stock	Voting Power (%)(7)
Q-Jagged Peak Energy Investment Partners, LLC(3)	98.6%	136,836,969	64.8%
Management Member Executive Officers(4)	1.3%	13,362,728	6.3%
Other Management Members(5)	0.1%	12,230,399	5.8%
JPE Management Holdings LLC(6)	—	10,419,904	4.9%
	100.0%	172,850,000	81.9%

(1) The number of shares of common stock to be issued to our Existing Owners is based on an implied equity value of Jagged Peak Energy LLC immediately prior to this offering, based on an initial public offering price of $17.00 per share of common stock, the midpoint of the price range set forth on the cover page of this prospectus. Any increase or decrease (as applicable) of the assumed initial public offering price will result in an increase or decrease, respectively, in the number of shares of common stock to be received by the Management Members, including those who serve as our executive officers, and Management Holdco, and an equivalent decrease or increase, respectively, in the number of shares of common stock to be received by Quantum. Accordingly, any such change in our initial public offering price will not affect the aggregate numbers of shares of common stock held by our Existing Owners.

23,782,632 shares of common stock held by certain of the Management Members and Management Holdco are subject to a stockholders' agreement that provides for certain restrictions on transfer and further provides that Management Holdco and the Management Members party thereto will vote their shares of common stock in accordance with the direction of Quantum. See "Certain Relationships and Related Party Transactions".

(2) Does not include management incentive units, the terms of which are set forth in greater detail under "Executive Compensation and Other Information—Narrative Disclosure to Summary Compensation Table—Long-term incentives".

(3) A $1.00 increase (decrease) in the initial public offering price of $17.00 per share, the midpoint of the price range set forth on the cover page of this prospectus, would (decrease) increase the number of shares held by Quantum following this offering by (421,881) 474,616 shares.

(4) Includes Messrs. Jaggers, Howard, Hinds and Petry. A $1.00 increase (decrease) in this assumed common stock price would increase (decrease) the aggregate number of shares held by the Management Members that serve as our executive officers following this offering by 167,438 (188,366) shares.

(5) A $1.00 increase (decrease) in the initial public offering price of $17.00 per share, the midpoint of the price range set forth on the cover page of this prospectus, would increase (decrease) the aggregate number of shares held by the non-executive Management Members following this offering by 178,216 (200,494) shares.

(6) The shares of common stock held by Management Holdco will be subject to the vesting, forfeiture and other provisions set forth in the Amended and Restated Limited Liability Company Agreement of Management Holdco. A $1.00 increase (decrease) in the initial public offering price

of $17.00 per share, the midpoint of the price range set forth on the cover page of this prospectus, would increase (decrease) the number of shares held by Management Holdco following this offering by 76,228 (85,756) shares.

(7) Totals may not sum or recalculate due to rounding.

MANAGEMENT

The following table sets forth the names, ages and titles of our directors, director nominees and executive officers:

Name	Age	Position
Joseph N. Jaggers	63	Chairman, Chief Executive Officer and President
Robert W. Howard	62	Executive Vice President, Chief Financial Officer
Gregory S. Hinds	52	Executive Vice President, Development Planning & Acquisitions
Christopher I. Humber	43	Executive Vice President, General Counsel & Secretary
Mark R. Petry	61	Executive Vice President, Land
Charles D. Davidson	66	Director
S. Wil VanLoh, Jr.	46	Director
Blake A. Webster	39	Director
Roger L. Jarvis	62	Director Nominee
James J. Kleckner	59	Director Nominee
Michael C. Linn	64	Director Nominee
John R. Sult	57	Director Nominee
Dheeraj Verma	39	Director Nominee

Joseph N. Jaggers was appointed as our Chief Executive Officer and President and as Chairman of our board of directors in September 2016, and has served as Chairman, Chief Executive Officer and President of Jagged Peak Energy LLC since April 2013. Prior to that, Mr. Jaggers served as the President and Chief Executive Officer of Ute Energy LLC from July 2010 until its acquisition in November 2012. From November 2012 until April 2013, Mr. Jaggers oversaw the winding down of Ute Energy LLC and evaluated potential opportunities in anticipation of the formation of Jagged Peak Energy LLC. Mr. Jaggers began his career in the oil and natural gas industry in 1981, when he joined Amoco Production Company ("Amoco") in Lake Charles, Louisiana. Mr. Jaggers worked for 19 years with Amoco and its successor, BP p.l.c., holding positions of increasing responsibility, including operations, engineering and executive assignments, in a number of domestic and international locations. In July 2000, Mr. Jaggers joined Barrett Resources Corporation as President and Chief Operating Officer and served in that capacity until Barrett Resources Corporation's merger with The Williams Companies, Inc. in 2001 where he served as Regional Vice President until 2006. Mr. Jaggers served as President, Chief Operating Officer and Director of Bill Barrett Corporation from 2006 until July 2010. In October 2009, Mr. Jaggers was elected into the Wildcatter Hall of Fame for his distinguished work and contributions to the oil and natural gas industry by the Independent Producers Association of the Mountain States. Mr. Jaggers graduated from the United States Military Academy at West Point in 1975 with a bachelor of sciences degree, after which he served his country for six years as a member of the United States Army. Mr. Jaggers is an independent director of National Fuel Gas Company (NYSE: NFG).

We believe that Mr. Jaggers' extensive knowledge of the energy industry and our company, as well as his substantial business, leadership and management experience, bring important and valuable skills to our Board of Directors.

Robert W. Howard was appointed as our Executive Vice President, Chief Financial Officer in November 2016, prior to which he served as our Chief Financial Officer since September 2016. Mr. Howard has also served as Chief Financial Officer of Jagged Peak Energy LLC since April 2016. Prior to that, Mr. Howard served as Chief Financial Officer and Treasurer of Bill Barrett Corporation since March 2007. He served as Chief Financial Officer for Quantum Resources Management, a private oil and natural gas company headquartered in Denver, from May 2006 until March 2007. Previously, Mr. Howard served from January 2002 through May 2006 in various executive positions for Bill Barrett

Corporation, including Executive Vice President—Finance and Investor Relations and Treasurer from February 2003 until May 2006 and as Chief Financial Officer from January 2002 until February 2003. From August 2001 until December 2001, Mr. Howard served as Vice President—Finance and Administration and a director of AEC Oil & Gas (USA) Inc. From 1984 through its sale in 2001, Mr. Howard served in various positions at Barrett Resources Corporation, including as Senior Vice President—Investor Relations and Corporate Development and Senior Vice President Accounting and Finance and Treasurer. He earned a B.B.A. in Comprehensive Public Accounting from University of Wisconsin-Eau Claire in 1976.

Gregory S. Hinds was appointed as our Executive Vice President, Development Planning & Acquisitions in November 2016, and has served as Chief Operating Officer of Jagged Peak Energy LLC since April 2013. Prior to that, Mr. Hinds served as Chief Operating Officer of Ute Energy LLC from February 2011 until its acquisition in November 2012. From November 2012 until April 2013, Mr. Hinds oversaw the winding down of Ute Energy LLC and evaluated potential opportunities in anticipation of the formation of Jagged Peak Energy LLC. Mr. Hinds served in various capacities for Bill Barrett Corporation from June 2002 until February 2011, beginning as a geologist and ultimately serving as Vice President for the Uinta Basin. While at Bill Barrett Corporation, Mr. Hinds managed the development of both producing and exploratory plays in the Uinta Basin and was credited with the Discovery of the Year for 2005 by Oil & Gas Investor magazine. Mr. Hinds' prior experience includes work for Marathon Oil Corporation as Manager of Geology, Powder River Basin CBM Business Unit from 2001 to 2002, Pennaco Energy, Inc. as Manager of Geology from 1999 to 2001 and Barrett Resources Corporation as an exploration and operations geologist from 1993 to 1999. Mr. Hinds graduated from Louisiana State University in 1986 where he earned a B.S. in geology. He earned an M.S. in geology from Texas A&M University in 1990.

Christopher I. Humber was appointed as our Executive Vice President, General Counsel & Secretary in November 2016. Prior to joining us, he was a consultant to us and other exploration and production companies since his March 2016 departure from Bonanza Creek Energy, Inc., where he served as its Executive Vice President, General Counsel and Secretary since August 2014 and its Senior Vice President, General Counsel and Secretary prior to that since that company's initial public offering in December 2011. Prior to that, Mr. Humber was a practicing attorney focusing on securities, mergers and acquisitions and corporate finance matters for public and private companies as a partner with the law firm Kendall, Koenig & Oelsner PC in Denver, Colorado and an associate with the law firms Hogan & Hartson LLP (now Hogan Lovells US LLP) in Denver, Colorado and Arnold & Porter LLP (now Arnold & Porter Kaye Scholer LLP) in Washington, D.C. and McLean, Virginia. Mr. Humber graduated with high honors from Emory University School of Law, where he was Editor-in-Chief of the Emory Law Journal, and holds a Bachelor of Arts in Biology from the University of Colorado at Boulder.

Mark R. Petry was appointed as our Executive Vice President, Land in November 2016, and has served as Jagged Peak Energy LLC's Vice President, Land since May 2013. Prior to that, he served as Vice President, Business Development and Land Administration for Laramie Energy II, LLC since September 2007. His prior experience includes Rocky Mountain Land Manager at Anadarko Petroleum Corporation, various positions, including Vice President, Land, at Western Gas Resources, Inc. and various land and accounting positions at Ladd Petroleum Corporation. Mr. Petry graduated with honors from the University of Wyoming with a Bachelor of Science Degree in Finance and is a Certified Professional Landman (CPL). Mark is a member of the American Association of Professional Landmen (AAPL) and the Denver Association of Petroleum Landmen (DAPL).

Charles D. Davidson was appointed as a member of our board of directors in September 2016, and has served as a member of the board of directors of Jagged Peak Energy LLC since February 2016. Mr. Davidson is a Venture Partner with Quantum Energy Partners and serves on the firm's Investment Committee. He served as Chief Executive Officer of Noble Energy, Inc. from 2000 to 2014 and its

Chairman from 2000 until his retirement in May 2015. Before joining Noble Energy, Inc. Mr. Davidson was Chairman, President and Chief Executive of Vastar Resources, Inc., a publicly owned subsidiary of Atlantic Richfield Company ("ARCO"), which merged with BP in 2000. Prior to the formation of Vastar, he held a number of engineering, operations and executive assignments at ARCO. Mr. Davidson is currently an independent director of Loews Corporation (NYSE: L) and is a member of the Society of Petroleum Engineers, the American Institute of Chemical Engineers and the All-American Wildcatters. During his career, he has served in various professional, industry and community organizations and has been presented with numerous industry awards and honors, including being named by the Harvard Business Review as one of the top 100 Best-Performing CEOs in the World. He holds a bachelor's degree in chemical engineering from Purdue University and a master's degree in management from the University of Texas at Dallas.

We believe that Mr. Davidson's extensive and highly successful experience as a Chief Executive Officer and board member of a large public independent exploration and production company as well as his strong industry, financial and governance knowledge bring important and valuable skills to our Board of Directors.

S. Wil VanLoh, Jr. was appointed as a member of our board of directors in September 2016, and has served as a member of the board of directors of Jagged Peak Energy LLC since April 2013. Mr. VanLoh is the Founder and Chief Executive Officer of Quantum Energy Partners, which he founded in 1998. Quantum Energy Partners manages a family of energy-focused private equity funds, which, together with its affiliates, has had more than $11 billion of capital under stewardship. Mr. VanLoh is responsible for the leadership and overall management of the firm. Additionally, he leads the firm's investment strategy and capital allocation process, working closely with the investment team to ensure its appropriate implementation and execution. Prior to co-founding Quantum Energy Partners, Mr. VanLoh co-founded Windrock Capital, Ltd., an energy investment banking firm specializing in providing merger, acquisition and divestiture advice to and raising private equity for energy companies. Prior to co-founding Windrock, Mr. VanLoh worked in the energy investment banking groups of Kidder, Peabody & Co. and NationsBank. Mr. VanLoh serves on the boards of a number of portfolio companies of Quantum Energy Partners, all of which are private energy companies. Mr. VanLoh holds a B.B.A. in Finance from Texas Christian University.

We believe that Mr. VanLoh's extensive experience, both from investing in the energy industry since 1998 and serving as director for numerous private and public energy companies, brings important and valuable skills to our Board of Directors.

Blake A. Webster was appointed as a member of our board of directors in September 2016, and has served as a member of the board of directors of Jagged Peak Energy LLC since April 2013. Mr. Webster is currently a Managing Director with Quantum Energy Partners and has been with the firm since 2006. Mr. Webster participates in Quantum's investment activities, including investment sourcing, transaction structuring and execution, and working closely with portfolio companies in developing and executing their business plans. Mr. Webster currently serves on the board of directors of several other Quantum portfolio companies, including Crump Energy Partners II, LLC, Intensity Midstream, LLC, Oryx Midstream Services, LLC and Xplorer Midstream, LLC. Prior to joining Quantum in 2006, Mr. Webster was an Associate with Morgan Stanley in its Global Energy and Utilities Equity Research group. Mr. Webster holds a B.A. from the University of Texas at Austin, an M.B.A. from Rice University and is a CFA charterholder.

We believe that Mr. Webster's extensive experience, both from his roles in the energy industry and as a director for several Quantum portfolio companies, brings important and valuable skills to our Board of Directors.

Roger L. Jarvis will become a member of our board of directors and member of our audit committee in connection with our listing on the NYSE. Between August 2012 and May 2016, he served as Chairman of Common Resources III LLC, a privately held company engaged in the business of exploration for and production of hydrocarbons in the United States, subsequent to which he evaluated potential opportunities prior to becoming our director nominee. Mr. Jarvis previously served as Chairman of Common Resources II from May 2010 until its acquisition in August 2012 and at Common Resources LLC from 2007 until its acquisition in May 2010. He served as Chairman, President, Chief Executive Officer and Director of Spinnaker Exploration Company, a natural gas and oil exploration and production company, from 1996 and as its Chairman of the Board from 1998, until its acquisition by Norsk Hydro ASA in December 2005. Mr. Jarvis holds a B.S in Petroleum Engineering from the University of Tulsa. He currently serves on the board of directors of National Oilwell Varco, Inc. (NYSE: NOV) where he is chairman of the nominating and corporate governance committee.

We believe that Mr. Jarvis, by serving as the chief executive officer and chairman of the board of a publicly traded company in the oil and gas industry for ten years, and as a result of his extensive experience in the oil and gas exploration and production industry, brings significant value to our board of directors. As a result of this extensive experience, Mr. Jarvis is very familiar with the strategic and project planning processes that impact our business. He has also gained valuable outside board experience from his tenure as a director of other public companies.

James J. Kleckner will become a member of our board of directors and member of our audit committee in connection with our listing on the NYSE. Mr. Kleckner retired from Anadarko Petroleum Corporation as its Executive Vice President, International and Deepwater Operations in August of 2016, a position he held since 2013, subsequent to which he evaluated potential opportunities prior to becoming our director nominee. From 2007 to 2013, he served as a Regional Vice President, Operations for Anadarko. From 1999 through 2007 he held various vice president positions with Kerr McGee Corporation. Prior to that, Mr. Kleckner spent almost 20 years in operational and officer roles with Oryx Energy until its merger with Kerr McGee. Mr. Kleckner began his career in the oil and natural gas industry with Sun Oil Company and has held positions of increasing responsibility throughout the world, including management roles in the North Sea, South America, China, the Gulf of Mexico and U.S. onshore. Mr. Kleckner holds a B.S. in Petroleum Engineering from the Colorado School of Mines. He is a member of the Society of Petroleum Engineers. He has served on the Industry and Advisory Board of the School of Energy Research at the University of Wyoming, the Petroleum Engineering Advisory Board at Colorado School of Mines, the Executive Board for the Colorado Oil and Gas Association and the Executive Board for the Independent Petroleum Association of Mountain States.

We believe Mr. Kleckner's significant operational experience as an executive of other oil and gas companies brings essential skills and perspectives to our board.

Michael C. Linn will become a member of our board of directors in connection with our listing on the NYSE. Mr. Linn is President and Chief Executive Officer of MCL Ventures LLC, a private oil, gas and real estate investment firm he founded in October 2011, and is a Senior Advisor with Quantum Energy Partners, a position he has held since August 2012. Mr. Linn founded Linn Energy, LLC ("LINN") (OTC: LINE), an independent oil and natural gas company, in 2003. He served as LINN's Executive Chairman from January 2010 to December 2011, Chairman and Chief Executive Officer from June 2006 to January 2010, and President and Chief Executive Officer from March 2003 to June 2006. Mr. Linn currently serves on the Board of Directors of LINN Energy, LLC, the Board of Directors of LinnCo, LLC (OTC: LNCOQ), the Board of Directors of Black Stone Minerals, L.P. (NYSE: BSM), the Board of Directors and Chairman of the Compensation Committee for Nabors Industries, Ltd. (NYSE: NBR), the Board of Directors and Chairman of the Conflicts Committee for Western Refining Logistics GP, LLC, the general partner of Western Refining Logistics, LP (NYSE: WNRL), and on the Board of Managers for Cavallo Mineral Partners, LLC. Mr. Linn previously served as a non-executive director and chairman of the SHESEC committee for Centrica plc. Mr. Linn currently serves as a member of the National Petroleum Council and Independent Petroleum Association of America ("IPAA") and previously served as chairman and director of the Natural Gas Council, chairman of the IPAA and director of the Natural Gas Supply Association. Mr. Linn holds a B.A. in Political Science from Villanova University and a J.D. from the University of Baltimore School of Law.

We believe that Mr. Linn's extensive experience as the Chief Executive Officer and director of a large public independent exploration and production company, his experience serving as a director for numerous public and private energy companies and his extensive industry knowledge, governance experience and relationships, provide valuable resources to our Board of Directors.

John R. "J.R." Sult will become a member of our board of directors and the chairman of our audit committee in connection with our listing on the NYSE. Mr. Sult served as Executive Vice President and Chief Financial Officer of Marathon Oil Corporation from September 2013 until August 2016, subsequent to which he evaluated potential opportunities prior to becoming our director nominee. He was Executive Vice President and Chief Financial Officer of El Paso Corporation ("El Paso") from March 2010 until May 2012 where he previously served as Senior Vice President and Chief Financial Officer from November 2009 until March 2010, and as Senior Vice President and Controller from November 2005 until November 2009. During the period from May 2012 to October 2012, Mr. Sult evaluated additional potential opportunities. He joined the board of directors of Dynegy, Inc. in October 2012. Mr. Sult also served as Executive Vice President, Chief Financial Officer and director of El Paso Pipeline GP Company, L.L.C., the general partner of El Paso Pipeline Partners, L.P., from July 2010 until May 2012, where he previously served as Senior Vice President and Chief Financial Officer from November 2009 until July 2010, and as Senior Vice President, Chief Financial Officer and Controller from August 2007 until November 2009. Mr. Sult also served as Chief Accounting Officer of El Paso and as Senior Vice President, Chief Financial Officer and Controller of El Paso's Pipeline Group from November 2005 to November 2009. Prior to joining El Paso, Mr. Sult served as Vice President and Controller of Halliburton Energy Services from August 2004 until October 2005. Prior to joining Halliburton, Mr. Sult managed an independent consulting practice that provided a broad range of finance and accounting advisory services and assistance to public companies in the energy industry. Prior to private practice, Mr. Sult was an audit partner with Arthur Andersen LLP. He graduated from Washington & Lee University with a B.S. with Special Attainments in Commerce. Mr. Sult currently serves on the board of directors and as audit committee chairman of Dynegy, Inc. (NYSE: DYN).

We believe that Mr. Sult, through his experience in executive financial positions with large public companies, brings significant knowledge of accounting, capital structures, finance, financial reporting, strategic planning and forecasting to our board of directors. In addition, we anticipate that Mr. Sult will satisfy the definition of an "audit committee financial expert".

Dheeraj "D" Verma will become a member of our board of directors in connection with our listing on the NYSE. Mr. Verma is the President of Quantum Energy Partners which he joined in 2008. Quantum manages a family of energy-focused private equity funds, which, together with its affiliates, has had more than $11 billion of capital under stewardship. Mr. Verma works with Mr. VanLoh in leading the firm's capital allocation process, charting the firm's investment strategy and overseeing all investment activities, working closely with the Executive Team and investment team to ensure its appropriate implementation and execution. Prior to joining Quantum, Mr. Verma was a senior member of J.P. Morgan's Mergers & Acquisitions group in New York, where he advised clients on over forty announced transactions with over $200 billion of enterprise value. He holds a B.A./B.S. in Mathematics and Finance from Ithaca College and a Masters in International Management from the Thunderbird School of Global Management. Mr. Verma serves on the boards of a number of portfolio companies of Quantum, all of which are private energy companies.

We believe that Mr. Verma's extensive experience, both from investing in the energy industry and serving as a director on numerous private energy company boards, brings important and valuable skills to our board of directors.

There are no family relationships among any of our directors, director nominees or executive officers.

Board of Directors

Our board of directors currently consists of four members, including our Chief Executive Officer and President, who serves as Chairman. Concurrently with the consummation of this offering, we will increase the size of our board to nine members, including our Chief Executive Officer and President, who will continue to serve as Chairman.

In connection with this offering, we will enter into a stockholders' agreement with Quantum, Management Holdco and certain of the Management Members. The stockholders' agreement is expected to provide Quantum with the right to designate a certain number of nominees to our board of directors so long as it and its affiliates collectively beneficially own at least 5% of the outstanding shares of our common stock. See "Certain Relationships and Related Party Transactions—Stockholders' Agreement" and "Risk Factors—Risks Related to this Offering and Our Common Stock—Quantum will have the ability to direct the voting of a majority of our common stock, and its interests may conflict with those of our other stockholders".

Initially, our board of directors will be divided into three classes of directors, with each class as equal in number as possible, serving staggered three year terms. For so long as Quantum beneficially owns or controls more than 50% of the voting power of our issued and outstanding common stock, such directors will generally be removable at any time, either for or without "cause", upon the affirmative vote of the holders of a majority of the outstanding shares of our issued and outstanding common stock entitled to vote generally for the election of directors. After Quantum no longer beneficially owns or controls more than 50% of the voting power of our issued and outstanding common stock, such directors will be removable only for "cause" upon the affirmative vote of the holders of at least 66⅔% of the outstanding shares of our issued and outstanding common stock entitled to vote generally for the election of directors.

In evaluating director candidates, we will assess whether a candidate possesses the integrity, judgment, knowledge, experience, skills and expertise that are likely to enhance the board of directors' ability to manage and direct our affairs and business, including, when applicable, to enhance the ability of the committees of the board of directors to fulfill their duties. Each of our directors holds office for the term for which he was elected, and until his successor shall have been elected and qualified or until the earlier of his death, resignation or removal.

Director Independence

We intend to appoint Messrs. Jarvis, Kleckner and Sult as independent directors to our board of directors contemporaneously with the completion of this offering. In making such appointments, our board of directors will review the independence of our directors using the independence standards of the NYSE.

Status as a Controlled Company

Because Quantum will beneficially own a majority of our outstanding common stock following the completion of this offering, we expect to be a controlled company under the NYSE corporate governance standards. A controlled company need not comply with NYSE corporate governance rules that require its board of directors to have a majority of independent directors and independent compensation and nominating and governance committees. Notwithstanding our status as a controlled company, we will remain subject to the NYSE corporate governance standard that requires us to have an audit committee composed entirely of independent directors. As a result, we must have at least one independent director on our audit committee by the effective date of the registration statement of which this prospectus forms a part, at least two independent directors within 90 days of such effective date and at least three independent directors within one year of such effective date.

If at any time we cease to be a controlled company, we will take all action necessary to comply with the rules, including appointing a majority of independent directors to our board of directors and ensuring we have a compensation committee and a nominating and corporate governance committee, each composed entirely of independent directors, subject to a permitted "phase-in" period. We will cease to qualify as a controlled company once Quantum ceases to control a majority of our voting stock.

Committees of the Board of Directors

Upon the conclusion of this offering, we intend to have an audit committee of our board of directors, and may have such other committees as the board of directors shall determine from time to time. We anticipate that each of the standing committees of the board of directors will have the composition and responsibilities described below.

Audit Committee

We will establish an audit committee prior to the completion of this offering. We anticipate that following completion of this offering, our audit committee will consist of Messrs. Jarvis, Kleckner and Sult, each of whom will be independent under the rules of the SEC. As required by the rules of the SEC and listing standards of the NYSE, the audit committee will consist solely of independent directors. SEC rules also require that a public company disclose whether or not its audit committee has an "audit committee financial expert" as a member. An "audit committee financial expert" is defined as a person who, based on his or her experience, possesses the attributes outlined in such rules. We anticipate that Mr. Sult, who we expect to serve as the chairman of our audit committee, will satisfy the definition of "audit committee financial expert".

This committee will oversee, review, act on and report on various auditing and accounting matters to our board of directors, including: the selection of our independent accountants, the scope of our annual audits, fees to be paid to the independent accountants, the performance of our independent accountants and our accounting practices. In addition, the audit committee will oversee our compliance programs relating to legal and regulatory requirements. We expect to adopt an audit committee charter defining the committee's primary duties in a manner consistent with the rules of the SEC and applicable stock exchange or market standards.

Compensation Committee

Because we will be a "controlled company" within the meaning of the NYSE corporate governance standards, we will not be required to, and do not currently expect to, have a compensation committee.

If and when we are no longer a "controlled company" within the meaning of the NYSE corporate governance standards, we will be required to establish a compensation committee. We anticipate that such a compensation committee would consist of three directors who will be "independent" under the rules of the SEC. This committee would establish salaries, incentives and other forms of compensation for officers and other employees. Any compensation committee would also administer our incentive compensation and benefit plans. Upon formation of a compensation committee, we would expect to adopt a compensation committee charter defining the committee's primary duties in a manner consistent with the rules of the SEC and applicable stock exchange or market standards.

Nominating and Corporate Governance Committee

Because we will be a "controlled company" within the meaning of the NYSE corporate governance standards, we will not be required to, and do not currently expect to, have a nominating and corporate governance committee.

If and when we are no longer a "controlled company" within the meaning of the NYSE corporate governance standards, we will be required to establish a nominating and corporate governance committee. We anticipate that such a nominating and corporate governance committee would consist of three directors who will be "independent" under the rules of the SEC. This committee would identify, evaluate and recommend qualified nominees to serve on our board of directors, develop and oversee our internal corporate governance processes and maintain a management succession plan. Upon formation of a nominating and corporate governance committee, we would expect to adopt a nominating and corporate governance committee charter defining the committee's primary duties in a manner consistent with the rules of the SEC and applicable stock exchange or market standards.

Compensation Committee Interlocks and Insider Participation

Because we will be a "controlled company" within the meaning of the NYSE corporate governance standards, we will not be required to, and do not currently expect to, have a compensation committee at the completion of this offering. 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

Prior to the completion of this offering, our board of directors will adopt a code of business conduct and ethics applicable to our employees, directors and officers, in accordance with applicable U.S. federal securities laws and the corporate governance rules of the NYSE. Any waiver of this code may be made only by our board of directors and will be promptly disclosed as required by applicable U.S. federal securities laws and the corporate governance rules of the NYSE.

Corporate Governance Guidelines

Prior to the completion of this offering, our board of directors will adopt corporate governance guidelines in accordance with the corporate governance rules of the NYSE.

DIVIDEND POLICY

We do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance our operations and 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 credit agreement places restrictions on our ability to pay cash dividends.

EXECUTIVE COMPENSATION AND OTHER INFORMATION

Executive Compensation

We are an "emerging growth company," as defined in the JOBS Act. As such, our named executive officers, or NEOs, consist of our predecessor's principal executive officer and the next two most highly compensated executive officers. For the fiscal year ending December 31, 2016, the NEOs were:

- Joseph N. Jaggers, Chairman, Chief Executive Officer and President;
- Gregory S. Hinds, Executive Vice President, Development Planning & Acquisitions; and
- Mark R. Petry, Executive Vice President, Land.

Summary compensation table

The table below sets forth the annual compensation earned during the fiscal year ended December 31, 2016 by our NEOs.

Name and Principal Position	Year	Salary ($)	Bonus ($)(1)	All Other Compensation ($)(2)	Total ($)
Joseph N. Jaggers	2016	324,450	(3)	4,015,900	4,340,350
(*Chairman, Chief Executive Officer and President*)	2015	322,996	173,982	24,000	520,978
Gregory S. Hinds	2016	297,413	(3)	3,015,900	3,313,313
(*Executive Vice President, Development Planning & Acquisitions*)	2015	296,080	148,706	17,078	314,080
Mark R. Petry	2016	248,745	(3)	1,315,900	1,564,645
(*Executive Vice President, Land*)					

(1) Amounts shown represent the payment of annual bonuses for the applicable year. For a description of annual bonuses for 2016 see the "—Narrative to Disclosure to Summary Compensation Table—Cash bonus" section below.

(2) "All Other Compensation" represents the matching contributions paid under our 401(k) plan and advances made in respect of management incentive units held by our NEOs in 2016. For a description of the management incentive unit advance, see the "—Narrative Disclosure to Summary Compensation Table—Long-term incentives" section below. We also provide partial parking and cell phone reimbursement benefits to all of our employees, including our NEOs, that are not disclosed as perquisites because the total amount of perquisites does not exceed the applicable disclosure threshold for any NEO.

(3) The annual bonus amount that will be paid to our NEOs in respect of 2016 was not determined through the latest practicable date. We expect such amounts to be determined within the first quarter of 2017.

Narrative Disclosure to Summary Compensation Table

Employment agreements

Each of our NEOs, other than Mr. Petry, has entered into an employment agreement (together, the "NEO Employment Agreements") with Jagged Peak Energy Management LLC, our predecessor's management company.

The NEO Employment Agreements provide for an initial base salary, which may be adjusted from time to time, as well as annual bonuses and long-term incentives in the form of management incentive units, each of which is described in greater detail below.

Under the terms of the NEO Employment Agreements, our NEOs are entitled to a lump sum severance payment equal to 200% of the sum of the executive's then-current annual base salary and target annual bonus upon their respective terminations of employment by us without "cause" or by the executive for "good reason" (as those terms are defined in the applicable NEO Employment Agreement), subject to the executive's execution of a release of claims.

We do not currently provide any additional or enhanced payments or benefits to our NEOs in connection with any change in control transactions.

Base salary

Each NEO's base salary is a fixed component of compensation for each year, which may be increased from time to time based on the individual's performance. Our NEOs' base salaries were originally set pursuant to negotiations with our Chief Executive Officer and President (or, in the case of our Chief Executive Officer and President, negotiations with certain members of the board of directors of our predecessor). As of December 31, 2016, each of our NEO's annualized base salaries was as follows: $324,450 for Mr. Jaggers, $297,412 for Mr. Hinds and $248,745 for Mr. Petry.

Cash bonus

The NEO Employment Agreements set a bonus potential for each NEO expressed as a percentage of the NEO's base salary. The board of directors of our predecessor has sole discretion to determine the bonus amount for each NEO, if any, based on numerous factors, including performance of Jagged Peak Energy LLC and individual performance. During 2017, Messrs. Jaggers and Hinds will each receive an annual bonus for 2016, which amounts have not yet been determined. The bonus potential set forth in each of the NEO Employment Agreements (expressed as a percentage of base salary) is as follows: 60% for Mr. Jaggers and 50% for Mr. Hinds. Mr. Petry is eligible to receive a discretionary bonus as determined by our Chief Executive Officer and President.

Long-term incentives

We have historically offered long-term incentives to our executive officers through grants of management incentive units in Jagged Peak Energy LLC. The management incentive units represent an interest in the future profits of Jagged Peak Energy LLC and are intended to be treated as "profits interests" for federal income tax purposes. The management incentive units are subject to time-vesting requirements and vesting upon certain corporate events (as described in further detail below). In addition to tax distributions on the management incentive units, which are paid if those holders are allocated taxable income in any quarter and are calculated based on a predetermined formula, after the other equity holders of Jagged Peak Energy LLC have received distributions equal to the capital contributed by such holders plus an annual internal rate of return equal to 8%, the management incentive units participate in distributions to all equity holders. We did not make any grants of management incentive units to our NEOs in 2016.

The number of management incentive units granted to our NEOs vest with respect to 18.75% on each of the first four anniversaries of May 3, 2013, with the remaining 25% vesting only upon a qualifying sale or public offering of Jagged Peak Energy LLC (a "Vesting Event"). Management incentive units vest over time, with a portion vesting only to the extent a Vesting Event occurs. However, both vested and unvested management incentive units will be forfeited upon a holder's termination of employment other than in limited circumstances. Notwithstanding the foregoing, all unvested management incentive units will automatically fully vest immediately prior to a Vesting Event.

In 2016, advances were made to our NEOs in respect of their outstanding management incentive units (the "MIU Advance") as follows: $4,000,000 to Mr. Jaggers, $3,000,000 to Mr. Hinds and $1,300,000 to Mr. Petry. Future distributions on the management incentive units held by our NEOs, including distributions in connection with our corporate reorganization and this offering as discussed below, will be reduced by the amount of the MIU Advance and the MIU Advance must be repaid, net of taxes, if a termination of employment occurs prior to the effective date of this offering. In accordance with Financial Accounting Standards Board Accounting Standards Codification Topic 710 ("ASC Topic 710"), the only compensation cost that has been recorded with respect to the management incentive units is in respect of the MIU Advance.

In addition, in connection with the grant of management incentive units to our NEOs, each executive has agreed not to solicit our employees or compete with us for a period of 12 months following the date such executive ceases to hold management incentive units for any reason other than due to a termination of such executive's employment without "cause" (as defined in the management Incentive Pool Plan or the applicable award letter).

In connection with this offering, we intend to convert the value of the management incentive units into shares of our common stock, a portion of which will be allocated to our NEOs and other executive officers in connection with this offering and a portion of which will be reserved for future issuances. A portion of the equity granted to our executive officers in connection with this offering will be vested and the remainder will be held by Management Holdco and generally will vest in equal installments on each of the first three anniversaries of this offering, so long as the holder remains continuously employed by us through each vesting date. The unvested equity will be held indirectly by management through Management Holdco as "Units". Each Unit will correspond to a share of our common stock. As each Unit vests, the employee will receive a share of our common stock, subject to certain negotiated transfer restrictions. Units that are forfeited will be reallocated to other members of management. Upon completion of this offering, the terms of vesting, forfeiture and the reallocation of forfeited Units will be governed by and set forth in, and may be amended only in certain limited circumstances in accordance with, the Amended and Restated Limited Liability Company Agreement of Management Holdco. The number of shares of our common stock allocated to Management Holdco with respect to unvested awards will be 9,831,669 and with respect to unallocated awards will be 588,235.

In addition to interests in Management Holdco, prior to the completion of this offering we expect to adopt the 2017 Long Term Incentive Plan, which is described in the "—Additional Narrative Disclosure—Long Term Incentive Plan" section below.

Other compensation elements

We offer participation in broad-based retirement, health and welfare plans to all of our employees. We currently maintain a plan intended to provide benefits under section 401(k) of the Code, where employees, including our NEOs, are allowed to contribute portions of their base compensation into a tax-qualified retirement account. We provide a matching contribution in amounts up to 6% of the employees' eligible compensation contributed by the employee to the plan.

We provide partial parking, cell phone reimbursement and non-discriminatory group-term life insurance benefits to our employees, including our NEOs, but otherwise do not provide for perquisites.

Outstanding equity awards at fiscal year-end

Although our NEOs hold management incentive units as described above in "—Narrative Disclosure to Summary Compensation Table—Long-term incentives," as of December 31, 2016, those awards were accounted for in accordance with ASC Topic 710 rather than ASC Topic 718. Therefore, as of December 31, 2016, the management incentive units did not represent equity awards within the meaning of applicable SEC guidance, and no equity awards were outstanding as of such date.

Additional Narrative Disclosure

Retirement Benefits

We have not maintained, and do not currently maintain a defined benefit pension plan or nonqualified deferred compensation plan. We currently maintain a plan intended to provide benefits under section 401(k) of the Code, where employees, including our NEOs, are allowed to contribute portions of their base compensation into a tax-qualified retirement account. We provide a matching contribution in amounts up to 6% of the employees' eligible compensation contributed by the employee to the plan.

Potential Payments upon Termination or a Change in Control

For a description of the material terms of the severance provisions of NEO Employment Agreements and the treatment of management incentive units in connection with this offering, please read "—Narrative Disclosure to Summary Compensation Table—Employment agreements" and "—Long-term incentives."

Long Term Incentive Plan

In order to incentivize individuals providing services to us or our affiliates, our board of directors intends to adopt the 2017 Long Term Incentive Plan (the "2017 LTIP") prior to the completion of this offering. We anticipate that the 2017 LTIP will provide for the grant, from time to time, at the discretion of our board of directors or a committee thereof, of stock options, stock appreciation rights ("SARS"), restricted stock, restricted stock units, stock awards, dividend equivalents, other stock-based awards, cash awards, substitute awards and performance awards. The description of the 2017 LTIP set forth below is a summary of the material anticipated features of the 2017 LTIP. This summary, however, does not purport to be a complete description of all of the anticipated provisions of the 2017 LTIP and is qualified in its entirety by reference to the 2017 LTIP, the form of which is filed as an exhibit to this registration statement.

2017 LTIP Share Limits. Subject to adjustment in the event of certain transactions or changes of capitalization in accordance with the 2017 LTIP, a total of 21,200,000 shares of our common stock will initially be reserved for issuance pursuant to awards under the 2017 LTIP. The total number of shares reserved for issuance under the 2017 LTIP may be issued pursuant to incentive stock options (which generally are stock options that meet the requirements of Section 422 of the Code). Common stock subject to an award that expires or is canceled, forfeited, exchanged, settled in cash or otherwise terminated without delivery of shares and shares withheld or surrendered to pay the exercise price of, or to satisfy the withholding obligations with respect to, an award will again be available for delivery pursuant to other awards under the 2017 LTIP.

Individual Share Limits. Beginning with the calendar year in which the transition period for the 2017 LTIP under Section 162(m) of the Code expires and for each calendar year thereafter, a "covered employee" (within the meaning of Section 162(m) of the Code) may not be granted awards under the 2017 LTIP intended to qualify as "performance-based compensation" (within the meaning of Section 162(m) of the Code) (i) to the extent such award is based on a number of shares of our common stock relating to more than, in the aggregate, 250,000 shares of common stock and (ii) to the extent such award is designated to be paid only in cash and is not based on a number of shares of our common stock, having an aggregate value determined on the respective dates of grant in excess of $5,000,000. Further, a non-employee member of our board of directors may not be granted awards under the 2017 LTIP relating, in the aggregate, to more than 30,000 shares or, if greater, having an aggregate value on the respective dates of grant in excess of $600,000. The foregoing non-employee director limit will be doubled during the first year of service as a non-employee member of our board of directors and will be determined without regard to grants of awards, if any, made to a non-employee member of our board of directors during any period in which such individual was an employee or consultant of the Company or any of its affiliates.

Administration. The 2017 LTIP will be administered by the compensation committee of our board of directors, which is referred to herein as the "committee," except to the extent our board of directors elects to administer the 2017 LTIP. Unless otherwise determined by our board of directors, the committee will be made up of two or more individuals who are (i) following the expiration of the transition period for the 2017 LTIP under Section 162(m) of the Code, "outside directors" as defined in Section 162(m) of the Code; (ii) a "nonemployee directors" as defined in Rule 16b-3 under the Exchange Act; and (iii) "independent" under the listing standards or rules of the securities exchange upon which our common stock is traded, but only to the extent such independence is required in order to take action at issue pursuant to such standards or rules. The committee has broad discretion to administer the 2017 LTIP, including the power to determine the eligible individuals to whom awards will be granted, the number and type of awards to be granted and the terms and conditions of awards. The committee may also accelerate the vesting or exercise of any award and make all other determinations. The committee has the power to interpret and administer the 2017 LTIP and any award agreements and to take all other actions necessary or advisable for the administration of the 2017 LTIP.

Eligibility. Any individual who is our officer or employee or an officer or employee of any of our affiliates, and any other person who provides services to us or our affiliates, including members of our board of directors, are eligible to receive awards under the 2017 LTIP at the committee's discretion; provided, that, any such person must be our "employee" within the meaning of General Instruction A.1(a) to Form S-8 if such individual is granted an award that may be settled in shares of our common stock.

Stock Options. The committee may grant incentive stock options and options that do not qualify as incentive stock options, except that incentive stock options may only be granted to persons who are our employees or employees of one of our subsidiaries, in accordance with Section 422 of the Code. The exercise price of a stock option generally cannot be less than 100% of the fair market value of a share of our common stock on the date on which the option is granted and the option must not be exercisable for longer than ten years following the date of grant. In the case of an incentive stock option granted to an individual who owns (or is deemed to own) at least 10% of the total combined voting power of all classes of our capital stock, the exercise price of the stock option must be at least 110% of the fair market value of a share of our common stock on the date of grant and the option must not be exercisable more than five years from the date of grant.

Stock Appreciation Rights. A SAR is the right to receive an amount equal to the excess of the fair market value of one share of our common stock on the date of exercise over the grant price of the SAR. The grant price of a SAR generally cannot be less than 100% of the fair market value of a share of our common stock on the date on which the SAR is granted. The term of a SAR may not exceed ten years. SARs may be granted in connection with, or independent of, a stock option. SARs may be paid in cash, common stock or a combination of cash and common stock, as determined by the committee.

Restricted Stock. Restricted stock is a grant of shares of common stock subject to the restrictions on transferability and risk of forfeiture imposed by the committee. In the committee's discretion, dividends distributed prior to vesting may be subject to the same restrictions and risk of forfeiture as the restricted stock with respect to which the distribution was made.

Restricted Stock Units. A restricted stock unit is a right to receive cash, common stock or a combination of cash and common stock at the end of a specified period equal to the fair market value of one share of our common stock on the date of vesting. Restricted stock units may be subject to restrictions, including a risk of forfeiture, imposed by the committee.

Stock Awards. A stock award is a transfer of unrestricted shares of our common stock on terms and conditions determined by the committee.

Dividend Equivalents. Dividend equivalents entitle an individual to receive cash, shares of common stock, other awards, or other property equal in value to dividends or other distributions paid with respect to a specified number of shares of our common stock. Dividend equivalents may be awarded on a free-standing basis or in connection with another award (other than an award of restricted stock or a stock award). The committee may provide that dividend equivalents will be paid or distributed when accrued or at a later specified date, including at the same time and subject to the same restrictions and risk of forfeiture as the award with respect to which the dividends accrue if they are granted in tandem with another award.

Other Stock-Based Awards. Subject to limitations under applicable law and the terms of the 2017 LTIP, the committee may grant other awards related to our common stock. Such awards may include, without limitation, awards that are convertible or exchangeable debt securities, other rights convertible or exchangeable into our common stock, purchase rights for common stock, awards with value and payment contingent upon our performance or any other factors designated by the committee, and awards valued by reference to the book value of our common stock or the value of securities of, or the performance of, our affiliates.

Cash Awards. The 2017 LTIP will permit the grant of awards denominated in and settled in cash as an element of or supplement to, or independent of, any award under the 2017 LTIP.

Substitute Awards. Awards may be granted in substitution or exchange for any other award granted under the 2017 LTIP or any other right of an eligible person to receive payment from us. Awards may also be granted under the 2017 LTIP in substitution for similar awards held by individuals who become eligible persons as a result of a merger, consolidation or acquisition of another entity or the assets of another entity by or with us or one of our affiliates.

Performance Awards. Performance awards represent awards with respect to which a participant's right to receive cash, shares of our common stock, or a combination of both, is contingent upon the attainment of one or more specified performance measures during a specified period. The committee will determine the applicable performance period, the performance goals and such other conditions that apply to each performance award. The committee may use any business criteria and other measures of performance it deems appropriate in establishing the performance goals applicable to a performance award.

If the committee grants a performance award to a covered employee that is designated as performance-based compensation within the meaning of Section 162(m) of the Code, the grant, exercise, vesting and/or settlement of such award will be contingent upon achievement of one or more of the following business criteria for us, on a consolidated basis, and/or for specified subsidiaries, business or geographical units or our operating areas (except with respect to the total stockholder return and earnings per share criteria): (1) revenues, sales or other income; (2) cash flow, discretionary cash flow, cash flows from operations, cash flows from investing activities, cash flow returns and/or cash flows from financing activities; (3) return on net assets, return on assets, return on investment, return on capital, return on capital employed or return on equity; (4) income, operating income, net income or net income per share; (5) earnings, operating earnings or earnings, operating or contribution margin determined before or after any one or more of depletion, depreciation and amortization expense;

exploration and abandonments; impairment of oil and gas properties; impairment of inventory and other property and equipment; accretion of discount on asset retirement obligations; interest expense; net gain or loss on the disposition of assets; income or loss from discontinued operations, net of tax; noncash derivative related activity; amortization of stock-based compensation; income taxes; incentives or service fees; extraordinary, non-recurring or special items; or other items; (6) equity; net worth; tangible net worth; book capitalization; debt; debt, net of cash and cash equivalents; capital budget or other balance sheet goals; (7) debt or equity financings or improvement of financial ratings; (8) production volumes, production growth, or debt-adjusted production growth, which may be of oil, gas, natural gas liquids or any combination thereof; (9) general and administrative expenses; (10) proved reserves, reserve replacement, drillbit reserve replacement and/or reserve growth; (11) exploration, finding and/or development costs, capital expenditures, drillbit finding and development costs, operating costs (including lease operating expenses, severance taxes and other production taxes, gathering and transportation or other components of operating expenses), base operating costs, or production costs; (12) absolute or per-share net asset value; (13) Fair Market Value of the Stock, share price, share price appreciation, total stockholder return or payments of dividends; (14) achievement of savings from business improvement projects and achievement of capital projects deliverables; (15) working capital or working capital changes; (16) operating profit or net operating profit; (17) internal research or development programs; (18) geographic business expansion; (19) performance against environmental, ethics or sustainability targets; (20) safety performance and/or incident rate; (21) human resources management targets, including medical cost reductions, employee satisfaction or retention, workforce diversity, time to hire and completion of hiring goals; (22) satisfactory internal or external audits; (23) consummation, implementation, integration or completion of a change in control or other strategic partnerships, transactions, projects, processes or initiatives or other goals relating to acquisitions or divestitures (in whole or in part), joint ventures or strategic alliances; (24) regulatory approvals or other regulatory milestones; (25) legal compliance or risk reduction; (26) drilling results; (27) market share; (28) economic value added; (29) cost or debt reduction targets; (30) capital raises or capital efficiencies; (31) cycle ratio; (32) capital intensity; (33) 3P reserves; or (34) acreage additions. Any of the above goals may be determined pre-tax or post-tax, on an absolute, relative or debt-adjusted basis, as compared to the performance of a published or special index deemed applicable by the Committee including the Standard & Poor's 500 Stock Index or a group of comparable companies, as a ratio with other business criteria, as a ratio over a period of time or on a per unit of measure (such as per day, or per barrel, a volume or thermal unit of gas or a barrel-of-oil equivalent), on a per-share basis (basic or diluted), and on a basis of continuing operations only. The terms above may, but shall not be required to be, used as applied under generally accepted accounting principles, as applicable.

The committee may establish an unfunded pool, with the amount of such pool calculated using an objective formula based upon the level of achievement of one or more of the business criteria selected by the committee from the list set forth above. If a pool is established, the committee shall also establish the maximum amount payable to each covered employee from the pool for each performance period.

Transferability. Generally, unless the committee determines otherwise, awards granted under the 2017 LTIP are not transferable other than by will or the laws of descent and distribution or a domestic relations order entered or approved by a court of competent jurisdiction upon written request for such transfer, and all rights with respect to an award granted to a participant generally will be available during a participant's lifetime only to the participant. The committee may permit the transfer of awards to certain immediate family members or related family trusts, limited partnerships or similar entities in the form of a gift or on such other terms and conditions as the committee may establish. Notwithstanding any provision to the contrary, incentive stock options will not be transferable other than by will or the laws of descent and distribution.

Recapitalization. In the event of any change in our capital structure or business or other corporate transaction or event that would be considered an equity restructuring, the committee shall or may (as required by applicable accounting rules) equitably adjust the (i) aggregate number or kind of shares that may be delivered under the 2017 LTIP, (ii) the number or kind of shares or amount of cash subject to an award, (iii) the terms and conditions of awards, including the purchase price or exercise price of awards and performance goals, and (iv) the applicable share-based limitations with respect to awards provided in the 2017 LTIP, in each case to equitably reflect such event.

Change in Control. Except to the extent otherwise provided in any applicable award agreement, no award will vest solely upon the occurrence of a change in control. In the event of a change in control or other changes us or our common stock, the committee may, in its discretion, (i) accelerate the time of exercisability of an award, (ii) require awards to be surrendered in exchange for a cash payment (including canceling a stock option or SAR for no consideration if it has an exercise price or the grant price less than the value paid in the transaction), or (iii) make any other adjustments to awards that the committee deems appropriate to reflect the applicable transaction or event.

No Repricing. Except in connection with (i) the issuance of substitute awards granted to new service providers in connection with a transaction or (ii) in connection with adjustments to awards granted under the 2017 LTIP as a result of a transaction or recapitalization involving us, without the approval of the stockholders of the Company, the terms of outstanding options or SARs may not be amended to reduce the exercise price or grant price to grant a new option or SAR or other award in substitution for, or upon the cancellation of, any previously granted option or SAR that has the effect of reducing the exercise price or grant price thereof or to take any similar action that would have the same economic result.

Clawback. All awards granted under the 2017 LTIP are subject to reduction, cancelation or recoupment under any written clawback policy that we may adopt and that we determine should apply to awards under the 2017 LTIP.

Amendment and Termination. The 2017 LTIP will automatically expire on the tenth anniversary of its effective date. Our board of directors may amend or terminate the 2017 LTIP at any time, subject to stockholder approval if required by applicable law, rule or regulation, including the rules of the stock exchange on which our shares of common stock are listed. The committee may amend the terms of any outstanding award granted under the 2017 LTIP at any time so long as the amendment would not materially and adversely affect the rights of a participant under a previously granted award without the participant's consent.

Director Compensation

We did not award any compensation to our non-employee directors during 2016. Going forward, we believe that attracting and retaining qualified non-employee directors will be critical to the future value of our growth and governance. We also believe that the compensation package for our non-employee directors should require that a portion of the total compensation package be equity-based to align the interests of these directors with our equity holders.

Under the director compensation policy we expect to adopt in connection with this offering, we anticipate that each non-employee director will receive an annual cash retainer of $55,000, a cash payment of $1,500 for each board meeting attended and $1,000 for each audit committee meeting attended, and an annual equity grant of $135,000 that will vest on the one-year anniversary of the grant date. In addition, the chairman of the audit committee will receive an additional cash retainer of $20,000.

We anticipate that directors who are also our employees or employees of Quantum will not receive any additional compensation for their service on the board of directors.

PRINCIPAL AND SELLING STOCKHOLDERS

The following table sets forth the beneficial ownership of our common stock that, upon the consummation of our corporate reorganization and this offering, will be owned by:

- each of the selling stockholders;
- each person known to us to beneficially own more than 5% of any class of our outstanding common stock;
- each of our directors and director nominees;
- our Named Executive Officers; and
- all of our directors, director nominees and executive officers as a group.

The selling stockholders may be deemed under federal securities laws to be underwriters with respect to the shares of common stock they are offering hereby and any shares of common stock that they may sell pursuant to the underwriters' option to purchase additional shares of our common stock. For further information regarding material transactions between us and the selling stockholders, see "Certain Relationships and Related Party Transactions".

All information with respect to beneficial ownership has been furnished by the respective selling stockholders, 5% or more stockholders, directors or Named Executive Officers, as the case may be. Unless otherwise noted, the mailing address of each listed beneficial owner is c/o Jagged Peak Energy Inc., 1125 17th Street, Suite 2400, Denver, Colorado 80202.

The underwriters have an option to purchase a maximum of 5,733,750 additional shares from Quantum to cover over-allotments of shares.

The table below does not reflect any shares of common stock that directors, director nominees and executive officers may purchase in this offering through the directed share program described under "Underwriting (Conflicts of Interest)—Directed Share Program."

Name of Beneficial Owner(1)	Shares Beneficially Owned Before this Offering		Shares Offered Hereby (Assuming No Exercise of the Underwriters' Over-Allotment Option)	Shares Offered Hereby (Assuming the Underwriters' Over-Allotment Option is Exercised in Full)	Shares Beneficially Owned After this Offering (Assuming No Exercise of the Underwriters' Over-Allotment Option)		Shares Beneficially Owned After this Offering (Assuming the Underwriters' Over-Allotment Option is Exercised in Full)	
	Number	%			Number	%	Number	%
Selling Stockholders and Other 5% Stockholders:								
Q-Jagged Peak Energy Investment Partners, LLC(2)	147,094,501	79.7	10,257,532	15,991,282	136,836,969	64.8	131,103,219	62.1
Katherine M. Adair	202,448	*	22,647	22,647	179,801	*	179,801	*
Ryan J. Axlund	218,862	*	24,583	24,583	194,279	*	194,279	*
Chris R. Bairrington	984,881	*	110,625	110,625	874,256	*	874,256	*
Laurie A. Bales	2,904,220	1.6	239,688	239,688	2,664,531	1.3	2,664,531	1.3
Mary R. Barnes	54,437	*	3,529	3,529	50,907	*	50,907	*
Glenn R. Berglund	191,365	*	21,510	21,510	169,855	*	169,855	*
Phyllis R. Burley	273,578	*	30,729	30,729	242,849	*	242,849	*
Joshua J. Chevalier	930,166	*	104,480	104,480	825,686	*	825,686	*
Lynn M. Connelly	328,294	*	36,875	36,875	291,419	*	291,419	*
William W. Griffith	54,437	*	6,146	6,146	48,291	*	48,291	*
Gregory & Carol Hinds Family Trust(3)	588,237	*	176,471	176,471	411,767	*	411,767	*
James R. Kinser III Trust(4)	547,156	*	61,459	61,459	485,698	*	485,698	*
Dylan R. Morales	108,873	*	12,292	12,292	96,582	*	96,582	*
Ian T. Piper	656,587	*	73,750	73,750	582,837	*	582,837	*
Shonn D. Stahlecker	547,156	*	61,459	61,459	485,698	*	485,698	*
Directors, Director Nominees and Named Executive Officers:								
Joseph N. Jaggers(5)	6,770,395	3.7	—	—	6,770,395	3.2	6,770,395	3.2
Gregory S. Hinds(6)	3,836,678	2.1	479,377	479,377	3,357,301	1.6	3,357,301	1.6
Mark R. Petry	1,602,803	*	207,730	207,730	1,395,073	*	1,395,073	*
Charles D. Davidson	—	—	—	—	—	—	—	—
S. Wil VanLoh, Jr.(7)	—	—	—	—	—	—	—	—
Blake A. Webster	—	—	—	—	—	—	—	—
Roger L. Jarvis	—	—	—	—	—	—	—	—
James J. Kleckner	—	—	—	—	—	—	—	—
Michael C. Linn	—	—	—	—	—	—	—	—
John R. Sult	—	—	—	—	—	—	—	—
Dheeraj Verma	—	—	—	—	—	—	—	—
Directors, Director Nominees and Executive Officers as a Group (Thirteen Persons):	14,049,835	7.6	687,107	687,107	13,362,728	6.3	13,362,728	6.3

* Less than 1%.

(1) The amounts and percentages of common stock beneficially owned are reported on the bases of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a "beneficial owner" of a security if that person has or shares voting power, which includes the power to vote or direct the voting of such security, or investment power, which includes the power to dispose of or to direct the disposition of such

security. Securities that can be so acquired are deemed to be outstanding for purposes of computing such person's ownership percentage, but not for purposes of computing any other person's percentage. Under these rules, more than one person may be deemed beneficial owner of the same securities, and a person may be deemed to be a beneficial owner of securities as to which such person has no economic interest. Except as otherwise indicated in these footnotes, each of the beneficial owners has, to our knowledge, sole voting and investment power with respect to the indicated shares of common stock, except to the extent this power may be shared with a spouse.

(2) QEM V, LLC ("QEM V LLC") is the managing member of Q-Jagged Peak Energy Investment Partners, LLC ("Q-Jagged Peak"). QEM V LLC may be deemed to share voting and dispositive power over the securities held by Q-Jagged Peak and may also be deemed to be the beneficial owner of these securities. QEM V LLC disclaims beneficial ownership of such securities in excess of its pecuniary interest in the securities. Any decision taken by QEM V LLC to vote, or to direct to vote, and to dispose, or to direct the disposition of, the securities held by Q-Jagged Peak has to be approved by a majority of the members of its investment committee, which majority must include S. Wil VanLoh, Jr. Therefore, Mr. VanLoh may be deemed to share voting and dispositive power over the securities held by Q-Jagged Peak and may also be deemed to be the beneficial owner of these securities. Mr. VanLoh disclaims beneficial ownership of such securities in excess of his pecuniary interest in the securities. The number of shares reflected in the table above as beneficially owned by Q-Jagged Peak does not include 23,782,632 shares held by Management Holdco and certain of the Management Members, including Messrs. Jaggers, Hinds and Petry, which are subject to the terms of the stockholders' agreement, pursuant to which, among other things, Management Holdco and the Management Members party thereto will agree to vote all of their shares of common stock in accordance with the direction of Quantum. As a result of the stockholders' agreement, Q-Jagged Peak may be deemed to beneficially own the shares of common stock held by Management Holdco and such Management Members. Q-Jagged Peak disclaims beneficial ownership of such securities in excess of its pecuniary interest therein. The mailing address for Q-Jagged Peak is 1401 McKinney St., Suite 2700, Houston, Texas 77010.

(3) Gregory S. Hinds has voting and dispositive power over these shares.

(4) James R. Kinser has voting and dispositive power over these shares.

(5) Includes 459,674 shares of common stock held by Jaggers Investments, LLLP. Mr. Jaggers has sole voting and dispositive power over these shares. Jaggers Investments, LLLP is an entity, of which Mr. Jaggers is general partner, owned by Mr. Jaggers and certain members of his family. The number of shares reflected in the table above as beneficially owned by Mr. Jaggers does not include 10,419,904 shares held by Management Holdco, of which Mr. Jaggers is the sole manager and therefore may be deemed to be the beneficial owner of securities that it holds. Mr. Jaggers disclaims beneficial ownership of such securities in excess of his pecuniary interest therein.

(6) Includes 588,237 shares held by Gregory & Carol Hinds Family Trust over which Mr. Hinds has voting and dispositive power, as set forth under "Selling Stockholders and Other 5% Stockholders" in the table above.

(7) QEM V LLC is the managing member of Q-Jagged Peak. Any decision taken by QEM V LLC to vote, or to direct to vote, and to dispose, or to direct the disposition of, the securities held by Q-Jagged Peak has to be approved by a majority of the members of its investment committee, which majority must include Mr. VanLoh. Therefore, Mr. VanLoh may be deemed to share voting and dispositive power over the securities held by Q-Jagged Peak and may also be deemed to be the beneficial owner of these securities. Mr. VanLoh disclaims beneficial ownership of such securities in excess of his pecuniary interest in the securities.

CERTAIN RELATIONSHIPS AND RELATED PARTY TRANSACTIONS

Historical Transactions with Affiliates

Quantum employs certain members of our board of directors and, after giving effect to this offering, will own 64.8% of our common stock. Quantum owns a 41.5% interest in Oryx Midstream Services, LLC. Oryx Midstream Services, LLC provides midstream gathering services to us pursuant to a 12-year crude oil gathering agreement. Since January 1, 2014, we have paid aggregate fees to Oryx Midstream Services, LLC pursuant to the agreement of approximately $4.3 million.

Quantum owns a 61% interest in Phoenix Lease Services, LLC ("Phoenix"), and an indirect interest in Trident Water Services, LLC ("Trident"), a wholly owned subsidiary of Phoenix. We regularly lease frac tanks and other oil field equipment from Phoenix, and we regularly use water transfer services provided by Trident. We are under no obligation to use either provider, and both provide services only when selected as a vendor in our normal bidding process. Since January 1, 2014, we have paid aggregate fees to Phoenix and Trident of approximately $0.9 million and $2.1 million, respectively.

Further, Messrs. James T. Jaggers, Jonathan E. Jaggers and Joseph N. Jaggers, IV, sons of Mr. Joseph N. Jaggers, our Chief Executive Officer and President, are employed by us as Senior Reservoir Engineer, Facilities Engineer and District Production Manager, respectively. Consistent with market compensation for their services, Messrs. James T. Jaggers, Jonathan E. Jaggers and Joseph N. Jaggers, IV have earned approximately $1.2 million, $0.4 million and $1.1 million, respectively, in aggregate cash compensation, including advances made in 2016 in respect of management incentive units held thereby, during the approximately three-year period since January 1, 2014. In addition, each of Messrs. James T. Jaggers, Jonathan E. Jaggers and Joseph N. Jaggers received certain long-term incentives during the same period in the form of management incentive units, the terms of which are set forth in greater detail under "Executive Compensation and Other Information—Narrative Disclosure to Summary Compensation Table—Long-term incentives".

Corporate Reorganization

Pursuant to the terms of certain reorganization transactions that will be completed prior to the closing of this offering, as described in further detail under "Corporate Reorganization", we will indirectly acquire all of the membership interests in our predecessor in exchange for the issuance of all of our issued and outstanding shares of common stock (prior to the issuance of shares of common stock in this offering) to the Existing Owners.

Registration Rights Agreement

In connection with the closing of this offering, we will enter into a registration rights agreement with Quantum and certain of our existing stockholders, including certain members of our management team. Pursuant to the registration rights agreement, we have agreed to register the sale of shares of our common stock under certain circumstances.

Demand Rights

At any time after the 180 day lock-up period described in "Underwriting (Conflicts of Interest)—Lock-Up Agreements", and subject to the limitations set forth below, Quantum (or its permitted transferees) has the right to require us by written notice to prepare and file a registration statement registering the offer and sale of a certain number of its shares of common stock. Generally, we are required to file such registration statement within 15 days of such written notice. Subject to certain exceptions, we will not be obligated to effect a demand registration within 90 days after the closing of any underwritten offering of shares of our common stock.

We are also not obligated to effect any demand registration in which the amount of common stock to be registered has an aggregate value of less than $50 million. Once we are eligible to effect a registration on Form S-3, any such demand registration may be for a shelf registration statement. We will be required to use all commercially reasonable efforts to maintain the effectiveness of any such registration statement until all shares covered by such registration statement have been sold.

In addition, Quantum (or its permitted transferees) has the right to require us, subject to certain limitations, to effect a distribution of any or all of its shares of common stock by means of an underwritten offering. In general, any demand for an underwritten offering (other than the first requested underwritten offering made in respect of a prior demand registration, a requested underwritten offering made concurrently with a demand registration or a requested underwritten offering for less than certain specified amounts) shall constitute a demand request subject to the limitations set forth above.

Piggyback Rights

Subject to certain exceptions, if at any time we propose to register an offering of common stock or conduct an underwritten offering, whether or not for our own account, then we must notify Quantum and Messrs. Jaggers, Howard, Hinds and Petry (or their permitted transferees) of such proposal at least five business days before the anticipated filing date or commencement of the underwritten offering, as applicable, to allow them to include a specified number of their shares in that registration statement or underwritten offering, as applicable.

Conditions and Limitations; Expenses

These registration rights are subject to certain conditions and limitations, including the right of the underwriters to limit the number of shares to be included in a registration and our right to delay or withdraw a registration statement under certain circumstances. We will generally pay all registration expenses in connection with our obligations under the registration rights agreement, regardless of whether a registration statement is filed or becomes effective.

Stockholders' Agreement

In connection with this offering, we will enter into a stockholders' agreement with Quantum, Management Holdco and Messrs. Jaggers, Howard, Hinds and Petry. Summaries of certain material terms of the stockholders' agreement are set forth below.

Voting and Governance Matters

Among other things, the stockholders' agreement will provide that Management Holdco and the Management Members party thereto will vote all of their 23,782,632 shares of common stock (representing approximately 11.3% of our outstanding common stock) in accordance with the direction of Quantum.

Further, the stockholders' agreement will provide Quantum with the right to designate a number of nominees (each, a "Quantum Director") to our board of directors such that:

- at least a majority of the directors on the board are Quantum Directors for so long as Quantum and its affiliates collectively beneficially own at least 50% of the outstanding shares of our common stock;
- at least 35% of the directors of the board are Quantum Directors for so long as Quantum and its affiliates collectively beneficially own less than 50% but at least 25% of the outstanding shares of our common stock;

- at least one director of the board is a Quantum Directors for so long as Quantum and its affiliates collectively beneficially own less than 25% but at least 5% of the outstanding shares of our common stock; and
- once Quantum and its affiliates collectively own less than 5% of our common stock, Quantum will not have any board designation rights.

Pursuant to the stockholders' agreement, we, Management Holdco and the Management Members party thereto will be required to take all necessary action, to the fullest extent permitted by applicable law (including with respect to any fiduciary duties under Delaware law), to cause the election of the nominees designated by Quantum. Further, we, Quantum, Management Holdco and the Management Members party thereto will be required to take all necessary action, to the fullest extent permitted by applicable law (including with respect to any fiduciary duties under Delaware law), to cause our board of directors to include our Chief Executive Officer.

The rights granted to Quantum to designate directors are additive to and not intended to limit in any way the rights that Quantum or any of its affiliates may have to nominate, elect or remove our directors under our amended and restated certificate of incorporation, amended and restated bylaws or the DGCL.

Transfer Restrictions

Additionally, the stockholders' agreement will contain several provisions relating to the sale of our common stock by certain of the Management Members. Specifically, Messrs. Jaggers, Howard, Hinds and Petry have agreed not to transfer any shares of our common stock, subject to certain exceptions, prior to the third anniversary of the consummation of this offering. Such restrictions on transfer shall not apply, however, to shares received by such Management Members in respect of any capital interests that such Management Members held in Jagged Peak Energy LLC prior to the corporate reorganization discussed in "Corporate Reorganization", nor shall such restrictions on transfer apply to certain specified numbers of shares of our common stock received by such Management Members in respect of the management incentive units held by such Management Members prior to the corporate reorganization. Further, in certain circumstances, such restrictions shall cease to apply to any such Management Member in the event of his termination or resignation of employment.

Procedures for Approval of Related Party Transactions

Prior to the closing of this offering, we have not maintained a policy 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 common stock;
- 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 common stock, 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 common stock; 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.

We anticipate that our board of directors will adopt a written related party transactions policy prior to the completion of this offering. Pursuant to this policy, we expect that our audit committee will review all material facts of all Related Party Transactions.

DESCRIPTION OF CAPITAL STOCK

Upon completion of this offering, the authorized capital stock of Jagged Peak Energy Inc. will consist of 1,000,000,000 shares of common stock, $0.01 par value per share, of which 211,075,000 shares will be issued and outstanding, and 50,000,000 shares of preferred stock, $0.01 par value per share, of which no shares will be issued and outstanding.

The following summary of the capital stock and amended and restated certificate of incorporation and amended and restated bylaws of Jagged Peak Energy Inc. does not purport to be complete and is qualified in its entirety by reference to the provisions of applicable law and to our amended and restated certificate of incorporation and amended and restated bylaws, which are filed as exhibits to the registration statement of which this prospectus is a part.

Common Stock

Except as provided by law or in a preferred stock designation, holders of common stock are entitled to one vote for each share held of record on all matters submitted to a vote of the stockholders, will have the exclusive right to vote for the election of directors and do not have cumulative voting rights. Except as otherwise required by law, holders of common stock are not entitled to vote on any amendment to the amended and restated certificate of incorporation (including any certificate of designations relating to any series of preferred stock) that relates solely to the terms of any outstanding series of preferred stock if the holders of such affected series are entitled, either separately or together with the holders of one or more other such series, to vote thereon pursuant to our amended and restated certificate of incorporation (including any certificate of designations relating to any series of preferred stock) or pursuant to the DGCL. Subject to prior rights and preferences that may be applicable to any outstanding shares or series of preferred stock, holders of common stock are entitled to receive ratably in proportion to the shares of common stock held by them such dividends (payable in cash, stock or otherwise), if any, as may be declared from time to time by our board of directors out of funds legally available for dividend payments. All outstanding shares of common stock are fully paid and non-assessable, and the shares of common stock to be issued upon completion of this offering will be fully paid and non-assessable.

The holders of common stock have no preferences or rights of conversion, exchange, pre-emption or other subscription rights. There are no redemption or sinking fund provisions applicable to common stock. In the event of any voluntary or involuntary liquidation, dissolution or winding-up of our affairs, holders of common stock will be entitled to share ratably in our assets in proportion to the shares of common stock held by them that are remaining after payment or provision for payment of all of our debts and obligations and after distribution in full of preferential amounts to be distributed to holders of outstanding shares of preferred stock, if any.

We do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future. See "Dividend Policy".

Preferred Stock

Our amended and restated certificate of incorporation will authorize our board of directors, subject to any limitations prescribed by law, without further stockholder approval, to establish and to issue from time to time one or more classes or series of preferred stock, par value $0.01 per share, covering up to an aggregate of 50,000,000 shares of preferred stock. Each class or series of preferred stock will cover the number of shares and will have the powers, preferences, rights, qualifications, limitations and restrictions determined by the board of directors, which may include, among others, dividend rights, liquidation preferences, voting rights, conversion rights, preemptive rights and redemption rights. Except as provided by law or in a preferred stock designation, the holders of preferred stock will not be entitled to vote at or receive notice of any meeting of stockholders.

Anti-Takeover Effects of Provisions of Our Amended and Restated Certificate of Incorporation, Our Amended and Restated Bylaws and Delaware Law

Some provisions of Delaware law contain, and our amended and restated certificate of incorporation and our amended and restated bylaws will contain, provisions that could make the following transactions more difficult: acquisitions of us by means of a tender offer, a proxy contest or otherwise or removal of our incumbent officers and directors. These provisions may also have the effect of preventing changes in our management. It is possible that these provisions could make it more difficult to accomplish or could deter transactions that stockholders may otherwise consider to be in their best interest or in our best interests, including transactions that might result in a premium over the market price for our shares.

These provisions are expected to discourage coercive takeover practices and inadequate takeover bids. These provisions are also designed to encourage persons seeking to acquire control of us to first negotiate with us. We believe that the benefits of increased protection and our potential ability to negotiate with the proponent of an unfriendly or unsolicited proposal to acquire or restructure us outweigh the disadvantages of discouraging these proposals because, among other things, negotiation of these proposals could result in an improvement of their terms.

Delaware Law

Section 203 of the DGCL prohibits a Delaware corporation, including those whose securities are listed for trading on the NYSE, from engaging in any business combination with any interested stockholder for a period of three years following the date that the stockholder became an interested stockholder, unless:

- the transaction is approved by the board of directors before the date the interested stockholder attained that status;
- upon consummation of the transaction that resulted in the stockholder becoming an interested stockholder, the interested stockholder owned at least 85% of the voting stock of the corporation outstanding at the time the transaction commenced; or
- on or after such time the business combination is approved by the board of directors and authorized at a meeting of stockholders by at least two-thirds of the outstanding voting stock that is not owned by the interested stockholder.

We intend to elect to not be subject to the provisions of Section 203 of the DGCL in our amended and restated certificate of incorporation.

Our Amended and Restated Certificate of Incorporation and Our Amended and Restated Bylaws

Provisions of our amended and restated certificate of incorporation and our amended and restated bylaws, which will become effective upon the closing of this offering, may delay or discourage transactions involving an actual or potential change in control or change in our management, including transactions in which stockholders might otherwise receive a premium for their shares, or transactions that our stockholders might otherwise deem to be in their best interests. Therefore, these provisions could adversely affect the price of our common stock.

Among other things, upon the completion of this offering, our amended and restated certificate of incorporation and amended and restated bylaws will:

- establish advance notice procedures with regard to stockholder proposals relating to the nomination of candidates for election as directors or new business to be brought before meetings of our stockholders. These procedures provide that notice of stockholder proposals must be timely given in writing to our corporate secretary prior to the meeting at which the action is to be taken. Generally, to be timely, notice must be received at our principal executive offices not less than 90 days nor more than 120 days prior to the first anniversary date of the annual meeting for the preceding year. Our amended and restated bylaws will specify the requirements as to form and content of all stockholders' notices. These requirements may preclude stockholders from bringing matters before the stockholders at an annual or special meeting;

- provide our board of directors the ability to authorize undesignated preferred stock. This ability makes it possible for our board of directors to issue, without stockholder approval, preferred stock with voting or other rights or preferences that could impede the success of any attempt to change control of us. These and other provisions may have the effect of deferring hostile takeovers or delaying changes in control or management of our company;
- provide that the authorized number of directors may be changed only by resolution of the board of directors;
- provide that all vacancies, including newly created directorships, may, except as otherwise required by law or, if applicable, the rights of holders of a series of preferred stock, be filled by the affirmative vote of a majority of directors then in office, even if less than a quorum, or by Quantum, for so long as Quantum and its affiliates collectively beneficially own more than 50% of the outstanding shares of our common stock;
- provide for our board of directors to be divided into three classes of directors, with each class as nearly equal in number as possible, serving staggered three year terms, other than directors which may be elected by holders of preferred stock, if any. This system of electing and removing directors may tend to discourage a third party from making a tender offer or otherwise attempting to obtain control of us, because it generally makes it more difficult for stockholders to replace a majority of the directors;
- provide that our amended and restated bylaws can be amended by the board of directors; and
- at any time after Quantum and its affiliates no longer collectively beneficially own more than 50% of the outstanding shares of our common stock,
    - provide that any action required or permitted to be taken by the stockholders must be effected at a duly called annual or special meeting of stockholders and may not be effected by any consent in writing in lieu of a meeting of such stockholders, subject to the rights of the holders of any series of preferred stock with respect to such series (prior to such time, such actions may be taken without a meeting by written consent of holders of common stock having not less than the minimum number of votes that would be necessary to authorize such action at a meeting);
    - provide our amended and restated certificate of incorporation and amended and restated bylaws may be amended by the affirmative vote of the holders of at least two-thirds of our then outstanding common stock (prior to such time, our amended and restated certificate of incorporation and amended and restated bylaws may be amended by the affirmative vote of the holders of a majority of our then outstanding common stock);
    - provide that special meetings of our stockholders may only be called by the board of directors, the chief executive officer or the chairman of the board (prior to such time, a special meeting may also be called at the request of stockholders holding a majority of the outstanding shares entitled to vote); and
    - provide that the affirmative vote of the holders of at least two-thirds of the voting power of all then outstanding common stock entitled to vote generally in the election of directors shall be required to remove any or all of the directors from office and such removal may only be for cause (prior to such time, directors may be removed either with or without

cause by the affirmative vote of holders of a majority of our outstanding shares entitled to vote, or by the affirmative vote of a majority of the total number of directors then in office, even if less than a quorum).

Forum Selection

Our amended and restated certificate of incorporation will provide that unless we consent in writing to the selection of an alternative forum, the Court of Chancery of the State of Delaware will, to the fullest extent permitted by applicable law, be the sole and exclusive forum for:

- any derivative action or proceeding brought on our behalf;
- any action asserting a claim of breach of a fiduciary duty owed by any of our directors, officers, employees or agents to us or our stockholders;
- any action asserting a claim against us arising pursuant to any provision of the DGCL, our amended and restated certificate of incorporation or our amended and restated bylaws; or
- any action asserting a claim against us that is governed by the internal affairs doctrine.

Our amended and restated certificate of incorporation will also provide that any person or entity purchasing or otherwise acquiring any interest in shares of our capital stock will be deemed to have notice of, and to have consented to, this forum selection provision. Although we believe these provisions will benefit us by providing increased consistency in the application of Delaware law for the specified types of actions and proceedings, the provisions may have the effect of discouraging lawsuits against our directors, officers, employees and agents. The enforceability of similar exclusive forum provisions in other companies' certificates of incorporation has been challenged in legal proceedings, and it is possible that, in connection with one or more actions or proceedings described above, a court could rule that this provision in our amended and restated certificate of incorporation is inapplicable or unenforceable.

Limitation of Liability and Indemnification Matters

Our amended and restated certificate of incorporation will limit the liability of our directors for monetary damages for breach of their fiduciary duty as directors, except for liability that cannot be eliminated under the DGCL. Delaware law provides that directors of a company will not be personally liable for monetary damages for breach of their fiduciary duty as directors, except for liabilities:

- for any breach of their duty of loyalty to us or our stockholders;
- for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law;
- for unlawful payment of dividend or unlawful stock repurchase or redemption, as provided under Section 174 of the DGCL; or
- for any transaction from which the director derived an improper personal benefit.

Any amendment, repeal or modification of these provisions will be prospective only and would not affect any limitation on liability of a director for acts or omissions that occurred prior to any such amendment, repeal or modification.

Our amended and restated bylaws will also provide that we will indemnify our directors and officers to the fullest extent permitted by Delaware law. Our amended and restated bylaws also will permit us to purchase insurance on behalf of any officer, director, employee or other agent for any liability arising out of that person's actions as our officer, director, employee or agent, regardless of whether Delaware law would permit indemnification. We intend to enter into indemnification agreements with each of our current and future directors and executive officers. These agreements will require us to indemnify these individuals to the fullest extent permitted under Delaware law against liability that may arise by reason of their service to us, and to advance expenses incurred as a result of any proceeding against them as to which they could be indemnified. We believe that the limitation of liability provision that will be in our amended and restated certificate of incorporation and the indemnification agreements will facilitate our ability to continue to attract and retain qualified individuals to serve as directors and officers.

Transfer Agent and Registrar

The transfer agent and registrar for our common stock is Computershare Trust Company, N.A.

Listing

We have been authorized to list our common stock on the NYSE under the symbol “JAG”.

SHARES ELIGIBLE FOR FUTURE SALE

Prior to this offering, there has been no public market for our common stock. Future sales of our common stock in the public market, or the availability of such shares for sale in the public market, could adversely affect the market price of our common stock prevailing from time to time. As described below, only a limited number of shares will be available for sale shortly after this offering due to contractual and legal restrictions on resale. Nevertheless, sales of a substantial number of shares of our common stock in the public market after such restrictions lapse, or the perception that those sales may occur, could adversely affect the prevailing market price of our common stock at such time and our ability to raise equity-related capital at a time and price we deem appropriate.

Sales of Restricted Shares

Upon the closing of this offering, we will have outstanding an aggregate of 211,075,000 shares of common stock. Of these shares, all of the 38,225,000 shares of common stock to be sold in this offering will be freely tradable without restriction or further registration under the Securities Act, unless the shares are held by any of our "affiliates" as such term is defined in Rule 144 under the Securities Act. All remaining shares of common stock held by existing stockholders will be deemed "restricted securities" as such term is defined under Rule 144. The restricted securities were issued and sold by us in private transactions and are eligible for public sale only if registered under the Securities Act or if they qualify for an exemption from registration under Rule 144 or Rule 701 under the Securities Act, which rules are summarized below.

As a result of the lock-up agreements described below, the provisions of Rule 144 and Rule 701 under the Securities Act and the provisions of the stockholders' agreement and the Amended and Restated Limited Liability Company Agreement of Management Holdco, the shares of our common stock (excluding the shares to be sold in this offering) that will be available for sale in the public market are as follows:

- no shares will be eligible for sale on the date of this prospectus or prior to 180 days after the date of this prospectus; and
- 154,727,853 shares will be eligible for sale upon the expiration of the lock-up agreements, beginning 180 days after the date of this prospectus (subject to extension) and when permitted under Rule 144 or Rule 701.

Lock-up Agreements

We, all of our directors and executive officers, the selling stockholders and certain of our stockholders and employees have agreed or will agree that, subject to certain exceptions and under certain conditions, for a period of 180 days after the date of this prospectus, we and they will not, without the prior written consent of Citigroup Global Markets Inc., Credit Suisse Securities (USA) LLC and J.P. Morgan Securities LLC, dispose of or hedge any shares or any securities convertible into or exchangeable for shares of our capital stock. See "Underwriting (Conflicts of Interest)" for a description of these lock-up provisions.

Rule 144

In general, under Rule 144 under the Securities Act as currently in effect, a person (or persons whose shares are aggregated) who is not deemed to have been an affiliate of ours at any time during the three months preceding a sale, and who has beneficially owned restricted securities within the meaning of Rule 144 for at least six months (including any period of consecutive ownership of preceding non-affiliated holders) would be entitled to sell those shares, subject only to the availability of current public information about us. A non-affiliated person who has beneficially owned restricted securities within the meaning of Rule 144 for at least one year would be entitled to sell those shares without regard to the provisions of Rule 144.

A person (or persons whose shares are aggregated) who is deemed to be an affiliate of ours and who has beneficially owned restricted securities within the meaning of Rule 144 for at least six months would be entitled to sell within any three-month period a number of shares that does not exceed the greater of one percent of the then outstanding shares of our common stock or the average weekly trading volume of our common stock reported through the NYSE during the four calendar weeks preceding the filing of notice of the sale. Such sales are also subject to certain manner of sale provisions, notice requirements and the availability of current public information about us.

Rule 701

In general, under Rule 701 under the Securities Act, any of our employees, directors, officers, consultants or advisors who purchase or otherwise receive shares from us in connection with a compensatory stock or option plan or other written agreement before the effective date of this offering are entitled to sell such shares 90 days after the effective date of this offering in reliance on Rule 144, without having to comply with the holding period requirement of Rule 144 and, in the case of non-affiliates, without having to comply with the public information, volume limitation or notice filing provisions of Rule 144. The SEC has indicated that Rule 701 will apply to typical stock options granted by an issuer before it becomes subject to the reporting requirements of the Exchange Act, along with the shares acquired upon exercise of such options, including exercises after the date of this prospectus.

Stock Issued Under Employee Plans

We intend to file a registration statement on Form S-8 under the Securities Act to register shares issuable under our 2017 Long-Term Incentive Plan. This registration statement on Form S-8 is expected to be filed following the effective date of the registration statement of which this prospectus is a part and will be effective upon filing. Accordingly, shares registered under such registration statement may be made available for sale in the open market following the effective date, unless such shares are subject to vesting restrictions with us, Rule 144 restrictions applicable to our affiliates or the lock-up restrictions described above.

Stockholders' Agreement

In connection with the closing of this offering, we will enter into a stockholders' agreement with Quantum, Management Holdco and certain of the Management Members. Please read "Certain Relationships and Related Party Transactions—Stockholders' Agreement".

MATERIAL U.S. FEDERAL INCOME TAX CONSIDERATIONS FOR NON-U.S. HOLDERS

The following is a summary of the material U.S. federal income tax considerations related to the purchase, ownership and disposition of our common stock by a non-U.S. holder (as defined below), that holds our common stock as a "capital asset" (generally property held for investment). This summary is based on the provisions of the Code, U.S. Treasury regulations and administrative rulings and judicial decisions, all as in effect on the date hereof, and all of which are subject to change, possibly with retroactive effect. We have not sought any ruling from the Internal Revenue Service ("IRS") with respect to the statements made and the conclusions reached in the following summary, and there can be no assurance that the IRS or a court will agree with such statements and conclusions.

This summary does not address all aspects of U.S. federal income taxation that may be relevant to non-U.S. holders in light of their personal circumstances. In addition, this summary does not address the Medicare tax on certain investment income, U.S. federal gift or estate tax laws, any state, local or non-U.S. tax laws or any tax treaties. This summary also does not address tax considerations applicable to investors that may be subject to special treatment under the U.S. federal income tax laws, such as (without limitation):

- banks, insurance companies or other financial institutions;
- tax-exempt or governmental organizations;
- qualified foreign pension funds;
- dealers in securities or foreign currencies;
- traders in securities that use the mark-to-market method of accounting for U.S. federal income tax purposes;
- persons subject to the alternative minimum tax;
- partnerships or other pass-through entities for U.S. federal income tax purposes or holders of interests therein;
- persons deemed to sell our common stock under the constructive sale provisions of the Code;
- persons that acquired our common stock through the exercise of employee stock options or otherwise as compensation or through a tax-qualified retirement plan;
- certain former citizens or long-term residents of the United States;
- real estate investment trusts or regulated investment companies; and
- persons that hold our common stock as part of a straddle, appreciated financial position, synthetic security, hedge, conversion transaction or other integrated investment or risk reduction transaction.

PROSPECTIVE INVESTORS ARE ENCOURAGED TO CONSULT THEIR TAX ADVISORS WITH RESPECT TO THE APPLICATION OF THE U.S. FEDERAL INCOME TAX LAWS TO THEIR PARTICULAR SITUATION, AS WELL AS ANY TAX CONSEQUENCES OF THE PURCHASE, OWNERSHIP AND DISPOSITION OF OUR COMMON STOCK ARISING UNDER THE U.S. FEDERAL GIFT OR ESTATE TAX LAWS OR UNDER THE LAWS OF ANY STATE, LOCAL, NON-U.S. OR OTHER TAXING JURISDICTION OR UNDER ANY APPLICABLE TAX TREATY.

Non-U.S. Holder Defined

For purposes of this discussion, a "non-U.S. holder" is a beneficial owner of our common stock that is not for U.S. federal income tax purposes a partnership or any of the following:

- an individual who is a citizen or resident of the United States;
- a corporation (or other entity treated as a corporation for U.S. federal income tax purposes) created or organized in or under the laws of the United States, any state thereof or the District of Columbia;
- an estate the income of which is subject to U.S. federal income tax regardless of its source; or
- a trust (i) whose administration is subject to the primary supervision of a U.S. court and which has one or more United States persons who have the authority to control all substantial decisions of the trust or (ii) which has made a valid election under applicable U.S. Treasury regulations to be treated as a United States person.

If a partnership (including an entity or arrangement treated as a partnership for U.S. federal income tax purposes) holds our common stock, the tax treatment of a partner in the partnership generally will depend upon the status of the partner, the activities of the partnership and certain determinations made at the partner level. Accordingly, we urge partners in partnerships (including entities or arrangements treated as partnerships for U.S. federal income tax purposes) considering the purchase of our common stock to consult their tax advisors regarding the U.S. federal income tax considerations of the purchase, ownership and disposition of our common stock by such partnership.

Distributions

As described in the section entitled "Dividend Policy", we do not plan to make any distributions on our common stock for the foreseeable future. However, if we do make distributions of cash or property on our common stock, those distributions will constitute dividends for U.S. federal income tax purposes to the extent paid from our current or accumulated earnings and profits, as determined under U.S. federal income tax principles. To the extent those distributions exceed our current and accumulated earnings and profits, the distributions will be treated as a non-taxable return of capital to the extent of the non-U.S. holder's tax basis in our common stock and thereafter as capital gain from the sale or exchange of such common stock. See "—Gain on Disposition of Common Stock". Subject to the withholding rules under FATCA (as defined below) and with respect to effectively connected dividends, each of which is discussed below, any distribution made to a non-U.S. holder on our common stock generally will be subject to U.S. withholding tax at a rate of 30% of the gross amount of the distribution unless an applicable income tax treaty provides for a lower rate. To receive the benefit of a reduced treaty rate, a non-U.S. holder must provide the applicable withholding agent with an IRS Form W-8BEN or IRS Form W-8BEN-E (or other applicable or successor form) certifying qualification for the reduced rate.

Dividends paid to a non-U.S. holder that are effectively connected with a trade or business conducted by the non-U.S. holder in the United States (and, if required by an applicable income tax treaty, are treated as attributable to a permanent establishment maintained by the non-U.S. holder in the United States) generally will be taxed on a net income basis at the rates and in the manner generally applicable to United States persons (as defined under the Code). Such effectively connected dividends will not be subject to U.S. withholding tax if the non-U.S. holder satisfies certain certification requirements by providing the applicable withholding agent a properly executed IRS Form W-8ECI certifying eligibility for exemption. If the non-U.S. holder is a non-U.S. corporation, it may also be subject to a branch profits tax (at a 30% rate or such lower rate as specified by an applicable income tax treaty) on its effectively connected earnings and profits (as adjusted for certain items), which will include effectively connected dividends.

Gain on Disposition of Common Stock

Subject to the discussion below under "—Additional Withholding Requirements under FATCA", a non-U.S. holder generally will not be subject to U.S. federal income tax on any gain realized upon the sale or other disposition of our common stock unless:

- the non-U.S. holder is an individual who is present in the United States for a period or periods aggregating 183 days or more during the calendar year in which the sale or disposition occurs and certain other conditions are met;
- the gain is effectively connected with a trade or business conducted by the non-U.S. holder in the United States (and, if required by an applicable income tax treaty, is attributable to a permanent establishment maintained by the non-U.S. holder in the United States); or
- our common stock constitutes a United States real property interest by reason of our status as a United States real property holding corporation ("USRPHC") for U.S. federal income tax purposes.

A non-U.S. holder described in the first bullet point above will be subject to U.S. federal income tax at a rate of 30% (or such lower rate as specified by an applicable income tax treaty) on the amount of such gain, which generally may be offset by U.S. source capital losses.

A non-U.S. holder whose gain is described in the second bullet point above or, subject to the exceptions described in the next paragraph, the third bullet point above generally will be taxed on a net income basis at the rates and in the manner generally applicable to United States persons (as defined under the Code) unless an applicable income tax treaty provides otherwise. If the non-U.S. holder is a corporation, it may also be subject to a branch profits tax (at a 30% rate or such lower rate as specified by an applicable income tax treaty) on its effectively connected earnings and profits (as adjusted for certain items), which will include such gain.

Generally, a corporation is a USRPHC if the fair market value of its United States real property interests equals or exceeds 50% of the sum of the fair market value of its worldwide real property interests and its other assets used or held for use in a trade or business. We believe that we currently are, and expect to remain for the foreseeable future, a USRPHC for U.S. federal income tax purposes. However, as long as our common stock continues to be regularly traded on an established securities market, only a non-U.S. holder that actually or constructively owns, or owned at any time during the shorter of the five-year period ending on the date of the disposition or the non-U.S. holder's holding period for the common stock, more than 5% of our common stock will be taxable on gain realized on the disposition of our common stock as a result of our status as a USRPHC. If our common stock were not considered to be regularly traded on an established securities market during the calendar year in which the relevant disposition by a non-U.S. holder occurs, such holder (regardless of the percentage of our common stock owned) would be subject to U.S. federal income tax on a taxable disposition of our common stock (as described in the preceding paragraph), and a 15% withholding tax would apply to the gross proceeds from such disposition.

Non-U.S. holders should consult their tax advisors with respect to the application of the foregoing rules to their ownership and disposition of our common stock.

Backup Withholding and Information Reporting

Any dividends paid to a non-U.S. holder must be reported annually to the IRS and to the non-U.S. holder. Copies of these information returns may be made available to the tax authorities in the country in which the non-U.S. holder resides or is established. Payments of dividends to a non-U.S. holder generally will not be subject to backup withholding if the non-U.S. holder establishes an exemption by properly certifying its non-U.S. status on an IRS Form W-8BEN, IRS Form W-8BEN-E or other appropriate version of IRS Form W-8.

Payments of the proceeds from a sale or other disposition by a non-U.S. holder of our common stock effected by or through a U.S. office of a broker generally will be subject to information reporting and backup withholding (at the applicable rate) unless the non-U.S. holder establishes an exemption by properly certifying its non-U.S. status on an IRS Form W-8BEN, IRS Form W-8BEN-E or other appropriate version of IRS Form W-8 and certain other conditions are met. Information reporting and backup withholding generally will not apply to any payment of the proceeds from a sale or other disposition of our common stock effected outside the United States by a non-U.S. office of a broker. However, unless such broker has documentary evidence in its records that the holder is not a United States person and certain other conditions are met, or the non-U.S. holder otherwise establishes an exemption, information reporting will apply to a payment of the proceeds of the disposition of our common stock effected outside the United States by such a broker if it has certain relationships within the United States.

Backup withholding is not an additional tax. Rather, the U.S. income tax liability (if any) of persons subject to backup withholding will be reduced by the amount of tax withheld. If backup withholding results in an overpayment of taxes, a refund may be obtained, provided that the required information is timely furnished to the IRS.

Additional Withholding Requirements under FATCA

Sections 1471 through 1474 of the Code, and the Treasury regulations and administrative guidance issued thereunder ("FATCA"), impose a 30% withholding tax on any dividends paid on our common stock and on the gross proceeds from a disposition of our common stock (if such disposition occurs after December 31, 2018), in each case if paid to a "foreign financial institution" or a "non-financial foreign entity" (each as defined in the Code) (including, in some cases, when such foreign financial institution or non-financial foreign entity is acting as an intermediary), unless (i) in the case of a foreign financial institution, such institution enters into an agreement with the U.S. government to withhold on certain payments, and to collect and provide to the U.S. tax authorities substantial information regarding U.S. account holders of such institution (which includes certain equity and debt holders of such institution, as well as certain account holders that are non-U.S. entities with U.S. owners); (ii) in the case of a non-financial foreign entity, such entity certifies that it does not have any "substantial United States owners" (as defined in the Code) or provides the applicable withholding agent with a certification identifying the direct and indirect substantial United States owners of the entity (in either case, generally on an IRS Form W-8BEN-E); or (iii) the foreign financial institution or non-financial foreign entity otherwise qualifies for an exemption from these rules and provides appropriate documentation (such as an IRS Form W-8BEN-E). Foreign financial institutions located in jurisdictions that have an intergovernmental agreement with the United States governing these rules may be subject to different rules. Under certain circumstances, a holder might be eligible for refunds or credits of such taxes.

INVESTORS CONSIDERING THE PURCHASE OF OUR COMMON STOCK ARE URGED TO CONSULT THEIR OWN TAX ADVISORS REGARDING THE APPLICATION OF THE U.S. FEDERAL INCOME TAX LAWS TO THEIR PARTICULAR SITUATIONS AND THE APPLICABILITY AND EFFECT OF U.S. FEDERAL GIFT AND ESTATE TAX LAWS AND ANY STATE, LOCAL OR NON-U.S. TAX LAWS AND TAX TREATIES.

UNDERWRITING (CONFLICTS OF INTEREST)

Citigroup Global Markets Inc., Credit Suisse Securities (USA) LLC and J.P. Morgan Securities LLC are acting as joint book-running managers of this offering and as representatives of each of the underwriters named below. Subject to the terms and conditions set forth in an underwriting agreement among us, the selling stockholders and the representatives, we and the selling stockholders have agreed to sell to the underwriters, and each of the underwriters has agreed, severally and not jointly, to purchase from us and the selling stockholders, the number of shares of common stock set forth opposite its name below.

Underwriter	Number of Shares
Citigroup Global Markets Inc.	
Credit Suisse Securities (USA) LLC	
J.P. Morgan Securities LLC	
Goldman, Sachs & Co.	
RBC Capital Markets, LLC	
Wells Fargo Securities, LLC	
UBS Securities LLC	
KeyBanc Capital Markets Inc.	
ABN AMRO Securities (USA) LLC	
Fifth Third Securities, Inc.	
Petrie Partners Securities, LLC	
Tudor, Pickering, Holt & Co. Securities, Inc.	
BMO Capital Markets Corp.	
Deutsche Bank Securities Inc.	
Evercore Group L.L.C.	
Scotia Capital (USA) Inc.	
Total	38,225,000

Subject to the terms and conditions set forth in the underwriting agreement, the underwriters have agreed, severally and not jointly, to purchase all of the shares sold under the underwriting agreement if any of these shares are purchased, other than the shares covered by the option described below unless and until this option is exercised.

We and the selling stockholders have agreed to indemnify the underwriters against certain liabilities, including liabilities under the Securities Act, and to contribute to payments the underwriters may be required to make for certain liabilities.

The underwriters are offering the shares, subject to prior sale, when, as and if issued to and accepted by them, subject to approval of legal matters by their counsel, including the validity of the shares, and other conditions contained in the underwriting agreement, such as the receipt by the underwriters of officer's certificates and legal opinions. The underwriters reserve the right to withdraw, cancel or modify offers to the public and to reject orders in whole or in part.

The selling stockholders may be "underwriters" within the meaning of the Securities Act and may be subject to certain statutory liabilities under the Securities Act.

Commissions and Discounts

The underwriters have advised us and the selling stockholders that they propose to offer the shares of common stock directly to the public at the public offering price set forth on the cover page of this prospectus and to dealers at the public offering price less a selling concession not in excess of $

per share. The underwriters also may allow, and dealers may reallow, a concession not in excess of $ per share to brokers and dealers. After the offering, the underwriters may change the offering price and the other selling terms.

The following table shows the public offering price, underwriting discounts and commissions, proceeds before expenses to us and proceeds to the selling stockholders. The information assumes either no exercise or full exercise by the underwriters of their option to purchase additional shares.

	Per Share	No Exercise	Full Exercise
Public offering price	$	$	$
Underwriting discounts and commissions paid by us			
Underwriting discounts and commissions paid by selling stockholders			
Proceeds, before expenses, to us			
Proceeds to selling stockholders			

In addition to the underwriting discounts and commissions to be paid by us, we have agreed to reimburse the underwriters for certain of their out-of-pocket expenses incurred in connection with this offering, including the reasonable fees and disbursements of counsel for the underwriters in connection with any required review of the terms of the directed share program and any required review of the offering by FINRA, which we estimate to be approximately $30,000. In addition, we have agreed to pay certain expenses incurred by the selling stockholders in connection with this offering, other than the underwriting discounts and commissions. We estimate that the total expenses of the offering payable by us, other than underwriting discounts and commissions, will be approximately $4.5 million.

Option to Purchase Additional Shares

Quantum has granted to the underwriters a 30-day option to purchase up to an aggregate of 5,733,750 additional shares of common stock at the public offering price less the underwriting discounts and commissions. The underwriters may exercise this option solely for the purpose of covering over-allotments, if any, made in connection with the offering of the shares of common stock offered by this prospectus. The underwriters may exercise that option for 30 days. If any shares are purchased pursuant to this option, the underwriters will severally purchase shares in approximately the same proportion as set forth in the table above.

Lock-Up Agreements

We, each of our executive officers, directors and director nominees and the selling stockholders have agreed not to do, or publicly announce an intention to do, any of the following, directly or indirectly, for 180 days after the date of this prospectus without the prior written consent of Citigroup Global Markets Inc., Credit Suisse Securities (USA) LLC and J.P. Morgan Securities LLC:

- offer, sell, contract to sell, pledge or otherwise dispose of, or enter into any transaction which is designed to or might reasonably be expected to result in the disposition of, shares of our common stock or any securities convertible into, or exercisable or exchangeable for, shares of our common stock;
- file or participate in the filing of a registration statement with the SEC (other than a registration statement on Form S-8) in respect of shares of our common stock or any securities convertible into, or exercisable or exchangeable for, shares of our common stock; or
- establish or increase a put equivalent position or liquidate or decrease a call equivalent position within the meaning of Section 16 of the Exchange Act in respect of shares of our common stock

or any securities convertible into, or exercisable or exchangeable for, shares of our common stock.

The restrictions described above do not apply to sales of common stock to the underwriters pursuant to this offering. Further, the restrictions described above do not apply, in our case, to the issuance of shares of common stock in connection with (i) our corporate reorganization as described under "Corporate Reorganization", (ii) any employee stock option plan, stock ownership plan or dividend reinvestment plan of in effect at or prior to the consummation of this offering, including, for avoidance of doubt, our 2017 Long-Term Incentive Plan, and (iii) any acquisition or strategic investment (including any joint venture or partnership) as long as (A) the aggregate number of such shares does not exceed 5% of the number of shares of common stock outstanding immediately after the consummation of this offering and (B) each recipient of any such shares issued or issuable agrees to restrictions on the resale of such shares that are consistent with the restrictions described above for the remainder of the applicable 180-day period. In the case of our executive officers, directors and director nominees and the selling stockholders, the restrictions described above do not apply to (i) any transactions relating to shares of common stock acquired in the open market after the consummation of this offering, (ii) the exercise or vesting of outstanding options and other equity-based awards granted pursuant to certain equity incentive and other plans, (iii) entry into new trading plans in compliance with Rule 10b5-1 of the Exchange Act; provided, however, that no sales of common stock or securities convertible into, or exchangeable or exercisable for, common stock, shall be made pursuant to such a trading plan prior to the expiration of the applicable 180-day period or (iv) or the exercise of rights with respect to, or the taking of action in preparation of, the registration by us under the Securities Act of such person's shares of common stock, provided that no transfer of such shares of common stock shall occur, and no registration shall be filed under the Securities Act with respect to any such shares of common stock, during the applicable 180-day period. In addition, the restrictions described above do not apply to certain collateral pledging transactions that may be entered into by Mr. Jaggers for a number of shares having an aggregate value no greater than $10 million based on the initial public offering price of our common stock, which would be 588,235 shares assuming the midpoint of the price range set forth on the cover of this prospectus.

Directed Share Program

At our request, the underwriters have reserved up to 5% of the shares for sale at the initial public offering price to persons who are directors, director nominees, officers or employees, or who are otherwise associated with us through a directed share program. The number of shares available for sale to the general public will be reduced by the number of directed shares purchased by participants in the program. Except for certain of our officers, directors, director nominees and employees who have entered into lock-up agreements, each person buying shares through the directed share program has agreed that, for a period of 180 days from the date of this prospectus, he or she will not, without the prior written consent of Citigroup Global Markets Inc., dispose of or hedge any shares purchased in the program or any securities convertible into or exchangeable for our common stock with respect to shares purchased in the program. For certain officers, directors and employees purchasing shares through the directed share program, the lock-up agreements described under "—Lock-Up Agreements" shall govern with respect to their purchases. Any directed shares not purchased will be offered by the underwriters to the general public on the same basis as all other shares offered. We have agreed to indemnify the underwriters against certain liabilities and expenses, including liabilities under the Securities Act, in connection with the sales of the directed shares.

New York Stock Exchange Listing

We have been authorized to list our common stock on the NYSE under the symbol "JAG". In order to meet the requirements for listing on that exchange, the underwriters have undertaken to sell a minimum number of shares to a minimum number of beneficial owners as required by that exchange.

Prior to this offering, there has been no public market for our common stock. The initial public offering price is determined by negotiations between us and the representatives. Among the factors to be considered in determining the initial public offering price will be the information set forth in this prospectus; our history, present state of development and future prospects; an assessment of our management, its past and present operations and the prospects for and timing of future revenues; the history of and future prospects for our industry in general; our sales, earnings and certain other financial and operating information in recent periods; and the price-earnings ratios, price-sales ratios, market prices of securities, valuation multiples and certain financial and operating information of companies engaged in activities similar to ours.

An active trading market for the shares may not develop. It is also possible that after the offering the shares will not trade in the public market at or above the initial public offering price.

Price Stabilization, Short Positions and Penalty Bids

Until the distribution of the shares is completed, SEC rules may limit underwriters from bidding for and purchasing our common stock. However, the underwriters may engage in transactions that stabilize the price of the common stock, such as bids or purchases to peg, fix or maintain that price.

In connection with the offering, the underwriters may purchase and sell our common stock in the open market. These transactions may include over-allotment and stabilizing transactions, passive market making and purchases to cover syndicate short positions created in connection with this offering. Short sales involve the sale by the underwriters of a greater number of shares than they are required to purchase in the offering. "Covered" short sales are sales made in an amount not greater than the underwriters' option to purchase additional shares described above. The underwriters may close out any covered short position by either exercising their option to purchase additional shares or purchasing shares in the open market. In determining the source of shares to close out the covered short position, the underwriters will consider, among other things, the price of shares available for purchase in the open market as compared to the price at which they may purchase shares through the option to purchase additional shares. "Naked" short sales are sales in excess of the option to purchase additional shares. The underwriters must close out any naked short position by purchasing shares in the open market. A naked short position is more likely to be created if the underwriters are concerned that there may be downward pressure on the price of our common stock in the open market after pricing that could adversely affect investors who purchase in the offering. Stabilizing transactions consist of various bids for or purchases of shares of common stock made by the underwriters in the open market prior to the completion of the offering.

The underwriters also may impose a penalty bid, whereby the underwriters may reclaim selling concessions allowed to syndicate members or other broker-dealers in respect of the common stock sold in the offering for their account if the underwriters repurchase the shares in stabilizing or covering transactions.

These activities may stabilize, maintain or otherwise affect the market price of the common stock, which may be higher than the price that might otherwise prevail in the open market. The underwriters may conduct these transactions on the NYSE, in the over-the-counter market or otherwise.

Neither we nor any of the underwriters make any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of our common stock. In addition, neither we nor any of the underwriters make any representation that the representatives will engage in these transactions or that these transactions, once commenced, will not be discontinued without notice.

Electronic Distribution

In connection with the offering, certain of the underwriters or securities dealers may distribute prospectuses by electronic means, such as e-mail.

Conflicts of Interest

An affiliate of Wells Fargo Securities, LLC is a lender under our existing credit facility and will receive 5% or more of the net proceeds of this offering due to the repayment of borrowings thereunder. Therefore, Wells Fargo Securities, LLC is deemed to have a conflict of interest within the meaning of FINRA Rule 5121. Accordingly, this offering is being conducted in accordance with Rule 5121, which requires, among other things, that a "qualified independent underwriter" participate in the preparation of, and exercise the usual standards of "due diligence" with respect to, the registration statement and this prospectus. Citigroup Global Markets Inc. has agreed to act as a qualified independent underwriter for this offering and to undertake the legal responsibilities and liabilities of an underwriter under the Securities Act, specifically including those inherent in Section 11 thereof. Citigroup Global Markets Inc. will not receive any additional fees for serving as a qualified independent underwriter in connection with this offering. We have agreed to indemnify Citigroup Global Markets Inc. against liabilities incurred in connection with acting as a qualified independent underwriter, including liabilities under the Securities Act.

Pursuant to Rule 5121, Wells Fargo Securities, LLC will not confirm any sales to any account over which it exercises discretionary authority without the specific written approval of the account holder.

Other Relationships

The underwriters and their respective affiliates are full service financial institutions engaged in various activities, which may include securities trading, commercial and investment banking, financial advisory, investment management, investment research, principal investment, hedging, financing and brokerage activities. The underwriters and certain of their affiliates have, from time to time, performed, and may in the future perform, various financial advisory and investment banking services for us, for which they received or will receive customary fees and expenses.

In the ordinary course of their various business activities, the underwriters and their respective affiliates may make or hold a broad array of investments and actively trade debt and equity securities (or related derivative securities) and financial instruments (including bank loans) for their own account and for the accounts of their customers, and such investment and securities activities may involve our securities and/or instruments. The underwriters and their respective affiliates may also make investment recommendations and/or publish or express independent research views in respect of such securities or instruments and may at any time hold, or recommend to clients that they acquire, long and/or short positions in such securities and instruments.

Notice to Prospective Investors in the European Economic Area

In relation to each Member State of the European Economic Area which has implemented the Prospectus Directive (each, a "Relevant Member State"), with effect from and including the date on which the Prospectus Directive is implemented in that Relevant Member State (the "Relevant Implementation Date"), no offer of shares may be made to the public in that Relevant Member State other than:

A. to any legal entity which is a qualified investor as defined in the Prospectus Directive;

B. to fewer than 100 or, if the Relevant Member State has implemented the relevant provision of the 2010 PD Amending Directive, 150, natural or legal persons (other than qualified investors as defined in the Prospectus Directive), as permitted under the Prospectus Directive, subject to obtaining the prior consent of the representatives; or

C. in any other circumstances falling within Article 3(2) of the Prospectus Directive, provided that no such offer of shares shall require us or the representatives to publish a prospectus pursuant to Article 3 of the Prospectus Directive or supplement a prospectus pursuant to Article 16 of the Prospectus Directive.

Each person in a Relevant Member State (other than a Relevant Member State where there is a Permitted Public Offer) who initially acquires any shares or to whom any offer is made will be deemed to have represented, acknowledged and agreed that (A) it is a "qualified investor" within the meaning of the law in that Relevant Member State implementing Article 2(1)(e) of the Prospectus Directive, and (B) in the case of any shares acquired by it as a financial intermediary, as that term is used in Article 3(2) of the Prospectus Directive, the shares acquired by it in the offering have not been acquired on behalf of, nor have they been acquired with a view to their offer or resale to, persons in any Relevant Member State other than "qualified investors" as defined in the Prospectus Directive, or in circumstances in which the prior consent of the Subscribers has been given to the offer or resale. In the case of any shares being offered to a financial intermediary as that term is used in Article 3(2) of the Prospectus Directive, each such financial intermediary will be deemed to have represented, acknowledged and agreed that the shares acquired by it in the offer have not been acquired on a non-discretionary basis on behalf of, nor have they been acquired with a view to their offer or resale to, persons in circumstances which may give rise to an offer of any shares to the public other than their offer or resale in a Relevant Member State to qualified investors as so defined or in circumstances in which the prior consent of the representatives has been obtained to each such proposed offer or resale.

We, the representatives and their affiliates will rely upon the truth and accuracy of the foregoing representation, acknowledgement and agreement.

This prospectus has been prepared on the basis that any offer of shares in any Relevant Member State will be made pursuant to an exemption under the Prospectus Directive from the requirement to publish a prospectus for offers of shares. Accordingly any person making or intending to make an offer in that Relevant Member State of shares which are the subject of the offering contemplated in this prospectus may only do so in circumstances in which no obligation arises for us or any of the underwriters to publish a prospectus pursuant to Article 3 of the Prospectus Directive in relation to such offer. Neither we nor the underwriters have authorized, nor do they authorize, the making of any offer of shares in circumstances in which an obligation arises for us or the underwriters to publish a prospectus for such offer.

For the purpose of the above provisions, the expression "an offer to the public" in relation to any shares in any Relevant Member State means the communication in any form and by any means of sufficient information on the terms of the offer and the shares to be offered so as to enable an investor to decide to purchase or subscribe the shares, as the same may be varied in the Relevant Member State by any measure implementing the Prospectus Directive in the Relevant Member State and the expression "Prospectus Directive" means Directive 2003/71/EC (including the 2010 PD Amending Directive, to the extent implemented in the Relevant Member States) and includes any relevant implementing measure in the Relevant Member State and the expression "2010 PD Amending Directive" means Directive 2010/73/EU.

Notice to Prospective Investors in Canada

The common stock may be sold in Canada only to purchasers purchasing, or deemed to be purchasing, as principal that are accredited investors, as defined in National Instrument 45-106

Prospectus Exemptions or subsection 73.3(1) of the Securities Act (Ontario), and are permitted clients, as defined in National Instrument 31-103 Registration Requirements, Exemptions and Ongoing Registrant Obligations. Any resale of the common stock must be made in accordance with an exemption from, or in a transaction not subject to, the prospectus requirements of applicable securities laws.

Securities legislation in certain provinces or territories of Canada may provide a purchaser with remedies for rescission or damages if this offering memorandum (including any amendment thereto) contains a misrepresentation, provided that the remedies for rescission or damages are exercised by the purchaser within the time limit prescribed by the securities legislation of the purchaser's province or territory. The purchaser should refer to any applicable provisions of the securities legislation of the purchaser's province or territory for particulars of these rights or consult with a legal advisor.

Pursuant to section 3A.3 of National Instrument 33-105 Underwriting Conflicts (NI 33-105), the underwriters are not required to comply with the disclosure requirements of NI 33-105 regarding underwriter conflicts of interest in connection with this offering.

Notice to Prospective Investors in the United Kingdom

In addition, in the United Kingdom, this document is being distributed only to, and is directed only at, and any offer subsequently made may only be directed at persons who are "qualified investors" (as defined in the Prospectus Directive) (i) who have professional experience in matters relating to investments falling within Article 19 (5) of the Financial Services and Markets Act 2000 (Financial Promotion) Order 2005, as amended (the "Order") and/or (ii) who are high net worth companies (or persons to whom it may otherwise be lawfully communicated) falling within Article 49(2)(a) to (d) of the Order (all such persons together being referred to as "relevant persons"). This document must not be acted on or relied on in the United Kingdom by persons who are not relevant persons. In the United Kingdom, any investment or investment activity to which this document relates is only available to, and will be engaged in with, relevant persons.

Notice to Prospective Investors in Switzerland

The shares may not be publicly offered in Switzerland and will not be listed on the SIX Swiss Exchange ("SIX") or on any other stock exchange or regulated trading facility in Switzerland. This document has been prepared without regard to the disclosure standards for issuance prospectuses under art. 652a or art. 1156 of the Swiss Code of Obligations or the disclosure standards for listing prospectuses under art. 27 ff. of the SIX Listing

Rules or the listing rules of any other stock exchange or regulated trading facility in Switzerland. Neither this document nor any other offering or marketing material relating to the shares or the offering may be publicly distributed or otherwise made publicly available in Switzerland.

Neither this document nor any other offering or marketing material relating to the offering, us, the shares have been or will be filed with or approved by any Swiss regulatory authority. In particular, this document will not be filed with, and the offer of shares will not be supervised by, the Swiss Financial Market Supervisory Authority FINMA ("FINMA"), and the offer of shares has not been and will not be authorized under the Swiss Federal Act on Collective Investment Schemes ("CISA"). The investor protection afforded to acquirers of interests in collective investment schemes under the CISA does not extend to acquirers of shares.

Notice to Prospective Investors in the Dubai International Financial Centre

This prospectus relates to an Exempt Offer in accordance with the Offered Securities Rules of the Dubai Financial Services Authority ("DFSA"). This prospectus is intended for distribution only to persons of a type specified in the Offered Securities Rules of the DFSA. It must not be delivered to, or relied on by, any other person. The DFSA has no responsibility for reviewing or verifying any documents in connection with Exempt Offers. The DFSA has not approved this prospectus nor taken steps to verify the information set forth herein and has no responsibility for the prospectus. The shares to which this prospectus relates may be illiquid and/or subject to restrictions on their resale. Prospective purchasers of the shares offered should conduct their own due diligence on the shares. If you do not understand the contents of this prospectus you should consult an authorized financial advisor.

Notice to Prospective Investors in Hong Kong, Singapore and Japan

The shares may not be offered or sold by means of any document other than (i) in circumstances which do not constitute an offer to the public within the meaning of the Companies Ordinance (Cap.32, Laws of Hong Kong), or (ii) to "professional investors" within the meaning of the Securities and Futures Ordinance (Cap.571, Laws of Hong Kong) and any rules made thereunder, or (iii) in other circumstances which do not result in the document being a "prospectus" within the meaning of the Companies Ordinance (Cap.32, Laws of Hong Kong), and no advertisement, invitation or document relating to the shares may be issued or may be in the possession of any person for the purpose of issue (in each case whether in Hong Kong or elsewhere), which is directed at, or the contents of which are likely to be accessed or read by, the public in Hong Kong (except if permitted to do so under the laws of Hong Kong) other than with respect to shares which are or are intended to be disposed of only to persons outside Hong Kong or only to "professional investors" within the meaning of the Securities and Futures Ordinance (Cap. 571, Laws of Hong Kong) and any rules made thereunder.

This prospectus has not been registered as a prospectus with the Monetary Authority of Singapore. Accordingly, this prospectus and any other document or material in connection with the offer or sale, or invitation for subscription or purchase, of the shares may not be circulated or distributed, nor may the shares be offered or sold, or be made the subject of an invitation for subscription or purchase, whether directly or indirectly, to persons in Singapore other than (i) to an institutional investor under Section 274 of the Securities and Futures Act, Chapter 289 of Singapore (the "SFA"), (ii) to a relevant person, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA or (iii) otherwise pursuant to, and in accordance with the conditions of, any other applicable provision of the SFA.

Where the shares are subscribed or purchased under Section 275 by a relevant person which is: (a) a corporation (which is not an accredited investor) the sole business of which is to hold investments and the entire share capital of which is owned by one or more individuals, each of whom is an accredited investor; or (b) a trust (where the trustee is not an accredited investor) whose sole purpose is to hold investments and each beneficiary is an accredited investor, shares, debentures and units of shares and debentures of that corporation or the beneficiaries' rights and interest in that trust shall not be transferable for 6 months after that corporation or that trust has acquired the shares under Section 275 except: (1) to an institutional investor under Section 274 of the SFA or to a relevant person, or any person pursuant to Section 275(1A), and in accordance with the conditions, specified in Section 275 of the SFA; (2) where no consideration is given for the transfer; or (3) by operation of law.

The securities have not been and will not be registered under the Financial Instruments and Exchange Law of Japan (the Financial Instruments and Exchange Law) and each underwriter has agreed that it will not offer or sell any securities, directly or indirectly, in Japan or to, or for the benefit of, any resident of Japan (which term as used herein means any person resident in Japan, including any corporation or other entity organized under the laws of Japan), or to others for re-offering or resale, directly or indirectly, in Japan or to a resident of Japan, except pursuant to an exemption from the registration requirements of, and otherwise in compliance with, the Financial Instruments and Exchange Law and any other applicable laws, regulations and ministerial guidelines of Japan.

LEGAL MATTERS

The validity of our common stock offered by this prospectus will be passed upon for us and the selling stockholders by Vinson & Elkins L.L.P., Houston, Texas. Certain legal matters in connection with this offering will be passed upon for the underwriters by Andrews Kurth Kenyon LLP, Houston, Texas.

EXPERTS

The consolidated financial statements of Jagged Peak Energy LLC as of and for the years ended December 31, 2015 and 2014 and the balance sheet of Jagged Peak Energy Inc. as of September 20, 2016 have been included herein. These reports have been included herein in reliance upon the reports of KPMG LLP, independent registered public accounting firm, appearing elsewhere herein, and upon the authority of said firm as experts in accounting and auditing.

Estimates of our reserves and related future net cash flows related to our properties as of November 30, 2016 and December 31, 2015 and 2014, included herein and elsewhere in the registration statement were based upon a reserve report prepared by independent petroleum engineers, Ryder Scott Company, LP. We have included these estimates in reliance on the authority of such firm as an expert in such matters.

WHERE YOU CAN FIND MORE INFORMATION

We have filed with the SEC a registration statement on Form S-1 (including the exhibits, schedules and amendments thereto) under the Securities Act, with respect to the shares of our common stock offered hereby. This prospectus does not contain all of the information set forth in the registration statement and the exhibits and schedules thereto. For further information with respect to the common stock offered hereby, we refer you to the registration statement and the exhibits and schedules filed therewith. Statements contained in this prospectus as to the contents of any contract, agreement or any other document are summaries of the material terms of such contract, agreement or other document and are not necessarily complete. With respect to each of these contracts, agreements or other documents filed as an exhibit to the registration statement, reference is made to the exhibits for a more complete description of the matter involved. A copy of the registration statement, and the exhibits and schedules thereto, may be inspected without charge at the public reference facilities maintained by the SEC at 100 F Street NE, Washington, D.C. 20549. Copies of these materials may be obtained, upon payment of a duplicating fee, from the Public Reference Room of the SEC at 100 F Street N.E., Washington, D.C. 20549. Please call the SEC at 1-800-SEC-0330 for further information on the operation of the Public Reference Room. The SEC maintains a website that contains reports, proxy and information statements and other information regarding registrants that file electronically with the SEC. The address of the SEC's website is *www.sec.gov*.

As a result of this offering, we will become subject to full information requirements of the Exchange Act. We will fulfill our obligations with respect to such requirements by filing periodic reports and other information with the SEC. We intend to furnish our stockholders with annual reports containing financial statements certified by an independent public accounting firm.

INDEX TO FINANCIAL STATEMENTS

Report of Independent Registered Public Accounting Firm

The Board of Directors
Jagged Peak Energy Inc.:

We have audited the accompanying balance sheet of Jagged Peak Energy Inc. as of September 20, 2016. This balance sheet is the responsibility of the Company's management. Our responsibility is to express an opinion on this balance sheet based on our audit.

We conducted our audit 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 balance sheet is free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the balance sheet. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall balance sheet presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the balance sheet referred to above presents fairly, in all material respects, the financial position of Jagged Peak Energy Inc. as of September 20, 2016, in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Denver, Colorado

October 11, 2016

JAGGED PEAK ENERGY INC.

BALANCE SHEET

	September 20, 2016
ASSETS	
CURRENT ASSETS	
Cash and cash equivalents	$ —
TOTAL ASSETS	$ —
LIABILITIES AND SHAREHOLDER'S EQUITY	
TOTAL LIABILITIES	
Total liabilities	$ —
SHAREHOLDER'S EQUITY	
Common stock, $0.01 par value, authorized 1,000 shares issued and outstanding	10
Less receivable from Jagged Peak Energy LLC	(10)
Total shareholder's equity	—
TOTAL LIABILITIES AND SHAREHOLDER'S EQUITY	$ —

The accompanying notes are an integral part of this balance sheet.

JAGGED PEAK ENERGY INC.

Notes to Balance Sheet

Note 1—Nature of Operations

Jagged Peak Energy Inc. (the "Company") is a Delaware corporation formed as a wholly owned subsidiary of Jagged Peak Energy LLC (the "Parent") on September 20, 2016. The Company was formed to become the holding company of the Parent in connection with the Company's initial public offering. The Company has no prior operating activities.

Pursuant to the terms of a corporate reorganization that will be completed prior to the closing of the initial public offering, the Company will acquire, directly or indirectly, all of the membership interests in the Parent in exchange for the issuance of all of the Company's issued and outstanding shares of common stock (prior to the issuance of shares of common stock in the initial public offering). As a result of these transactions, the Parent will become the Company's direct, wholly owned subsidiary.

Note 2—Basis of Presentation and Summary of Significant Accounting Policies

This balance sheet has been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). Separate Statements of Operations, Changes in Stockholder's Equity and of Cash Flows have not been presented because the Company has had no business transactions or activities to date, except for the initial capitalization of the Company which was funded by a receivable from the Parent. In this regard, general and administrative costs associated with the formation and daily management of the Company have been determined by the Company to be insignificant.

In preparing the accompanying balance sheet, the Company considered disclosures of events occurring after September 20, 2016, up until the issuance of the balance sheet.

Estimates

The preparation of the balance sheet, in accordance with generally accepted accounting principles in the United States of America, requires management to make estimates and assumptions that affect the amounts reported in the balance sheet and accompanying notes. Actual results could differ from those estimates.

Receivable from Jagged Peak Energy LLC

Receivable from Jagged Peak Energy LLC represents an amount of $10 due for the issuance of 1,000 shares of $.01 par value common stock to the Parent. Prior to payment by the Parent, this receivable will be recorded as a reduction of shareholder's equity.

Income Taxes

The Company is a subchapter C corporation and is subject to U.S. federal and state income taxes. Income taxes are accounted for under the asset and liability method. The Company recognizes deferred tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts and income tax basis of assets and liabilities and the expected benefits of utilizing net operating loss and tax credit carryforwards, using enacted tax rates in effect for the taxing jurisdiction in which the Company operates for the year in which those temporary differences are expected to be recovered or settled. The Company recognizes the financial statement effects of a tax position when it is more-likely-than-not, based on technical merits, that the position will

Note 2—Basis of Presentation and Summary of Significant Accounting Policies (Continued)

be sustained upon examination. Net deferred tax assets are then reduced by a valuation allowance if the Company believes it is more-likely-than-not such net deferred tax assets will not be realized.

Note 3—Shareholder's Equity

The Company has authorized share capital of 1,000 common shares with $0.01 par value. On September 20, 2016, all 1,000 shares were issued and acquired by the Parent for consideration of an amount of $10 receivable from the Parent. Each share has one voting right.

Report of Independent Registered Public Accounting Firm

The Board of Directors
Jagged Peak Energy LLC:

We have audited the accompanying consolidated balance sheets of Jagged Peak Energy LLC (Predecessor) and its subsidiaries as of December 31, 2015 and 2014, and the related consolidated statements of operations, members' equity, and cash flows for the years then ended. These consolidated financial statements are the responsibility of the Predecessor's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits 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. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Jagged Peak Energy LLC and its subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for the years then ended in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Denver, Colorado

October 11, 2016

JAGGED PEAK ENERGY LLC

(PREDECESSOR)

CONSOLIDATED BALANCE SHEETS

(in thousands)

	December 31, 2015	December 31, 2014
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 14,165	$ 33,628
Accounts receivable	8,005	1,739
Commodity derivative assets	—	4,612
Other current assets	504	773
Total current assets	22,674	40,752
PROPERTY AND EQUIPMENT		
Oil and natural gas properties, successful efforts method	333,067	222,293
Accumulated depletion, depreciation and amortization	(30,341)	(8,105)
Total oil and gas properties	302,726	214,188
Other property and equipment, net	1,663	2,000
Total property and equipment, net	304,389	216,188
OTHER NONCURRENT ASSETS		
Unamortized debt issuance costs	542	—
Other assets	127	144
Total other assets	669	144
TOTAL ASSETS	$327,732	$257,084
LIABILITIES AND MEMBERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 2,452	$ 2,202
Accrued liabilities	20,171	13,218
Total current liabilities	22,623	15,420
LONG-TERM LIABILITIES		
Senior secured revolving credit facility	20,000	—
Asset retirement obligations	490	401
Other long-term liabilities	289	449
Total long-term liabilities	20,779	850
MEMBERS' EQUITY		
Common units	294,556	243,556
Accumulated deficit	(10,226)	(2,742)
Total members' equity	284,330	240,814
TOTAL LIABILITIES AND MEMBERS' EQUITY	$327,732	$257,084

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

JAGGED PEAK ENERGY LLC

(PREDECESSOR)

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands)

	Years ended December 31,	
	2015	**2014**
REVENUES		
Oil sales	$31,534	$14,605
Natural gas sales	948	646
NGL sales	1,329	1,029
Total revenues	33,811	16,280
OPERATING EXPENSES		
Lease operating expenses	3,165	2,041
Gathering and transportation expenses	171	121
Production and ad valorem taxes	2,244	920
Depletion, depreciation, amortization and accretion	22,685	8,444
Impairment of oil and natural gas properties and dry hole costs	6,489	1,414
Other operating expenses	261	64
General and administrative	7,446	7,330
Total operating expenses	42,461	20,334
LOSS FROM OPERATIONS	(8,650)	(4,054)
OTHER INCOME (EXPENSE)		
Gain on commodity derivatives	1,323	5,375
Interest expense and other	(197)	—
Other income	40	—
Total other income	1,166	5,375
NET INCOME (LOSS)	$(7,484)	$ 1,321

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

JAGGED PEAK ENERGY LLC

(PREDECESSOR)

CONSOLIDATED STATEMENTS OF MEMBERS' EQUITY

(in thousands)

	Common Units	Accumulated Deficit	Total Members' Equity
BALANCE AT DECEMBER 31, 2013	$ 43,756	$ (4,063)	$ 39,693
Capital contributions	199,800	—	199,800
Net income	—	1,321	1,321
BALANCE AT DECEMBER 31, 2014	243,556	(2,742)	240,814
Capital contributions	51,000	—	51,000
Net loss	—	(7,484)	(7,484)
BALANCE AT DECEMBER 31, 2015	$294,556	$(10,226)	$284,330

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

JAGGED PEAK ENERGY LLC

(PREDECESSOR)

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)

	Years ended December 31, 2015	Years ended December 31, 2014
CASH FLOWS FROM OPERATING ACTIVITIES		
Net (loss) income	$ (7,484)	$ 1,321
Adjustments to reconcile net income (loss) to net cash provided by operating activities		
Depletion, depreciation, amortization and accretion expense	22,685	8,444
Impairment of oil and natural gas properties and dry hole costs	6,489	1,414
Amortization of debt issuance costs	61	—
Gain on commodity derivatives	(1,323)	(5,375)
Net cash receipts on settled derivatives	5,935	763
Other	(155)	(150)
Change in operating assets and liabilities:		
Accounts receivable and other current assets	(5,997)	(2,376)
Other assets	17	(28)
Accounts payable and accrued liabilities	144	3,602
Net cash provided by operating activities	20,372	7,615
CASH FLOWS FROM INVESTING ACTIVITIES		
Oil and natural gas leasehold and acquisition costs	(13,716)	(124,328)
Development of oil and natural gas properties	(96,743)	(64,545)
Other capital expenditures	(213)	(1,073)
Proceeds from sale of oil and natural gas properties	440	2,879
Net cash used in investing activities	(110,232)	(187,067)
CASH FLOWS FROM FINANCING ACTIVITIES		
Proceeds from common units issued	51,000	199,800
Proceeds from senior secured revolving credit facility	20,000	—
Debt issuance costs	(603)	—
Net cash provided by financing activities	70,397	199,800
NET CHANGE IN CASH AND CASH EQUIVALENTS	(19,463)	20,348
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	33,628	13,280
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 14,165	$ 33,628
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION		
Interest paid, net of capitalized interest	$ 95	$ —
Cash paid for income taxes	—	—
SUPPLEMENTAL DISCLOSURE OF NONCASH INVESTING ACTIVITIES		
Accrued capital expenditures	$ 17,720	$ 10,809
Asset retirement obligations	189	50

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

Note 1—Organization, Operations and Basis of Presentation

Organization and Operations

Jagged Peak Energy LLC (together with its subsidiaries, the "Predecessor"), a Delaware limited liability company, is a growth-oriented, independent oil and natural gas company focused on the acquisition and development of unconventional oil and associated liquids-rich natural gas reserves in the Delaware Basin, a sub-basin of the Permian Basin of West Texas. The Predecessor's acreage is located on large, contiguous blocks in the adjacent counties of Winkler, Ward, Reeves and Pecos, with significant oil-in-place within multiple stacked hydrocarbon-bearing formations. The Predecessor was formed by an affiliate of Quantum Energy Partners ("Quantum"), a leading energy private equity firm that has managed more than $11 billion of equity commitments since 1998, and key members of its management team.

Basis of Presentation

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

The accompanying consolidated financial statements include the accounts of Jagged Peak Energy LLC and its wholly owned subsidiaries. All significant intercompany amounts have been eliminated in consolidation.

Note 2—Significant Accounting Policies and Related Matters

Use of Estimates

In the course of preparing the consolidated financial statements, management makes various assumptions, judgments and estimates to determine the reported amounts of assets, liabilities, revenue and expenses, and in the disclosures of commitments and contingencies. Changes in these assumptions, judgments and estimates will occur as a result of the passage of time and the occurrence of future events. Although management believes these estimates are reasonable, actual results could differ from these estimates.

Estimates made in preparing these consolidated financial statements include, among other things, (1) estimates relating to certain oil and natural gas revenue and costs, (2) estimates of oil and natural gas reserve quantities, which impact depreciation, depletion and amortization and impairment calculations, (3) estimates of timing and costs used in calculating asset retirement obligations and impairment, (4) estimates used in developing fair value assumptions, including future cash flows and discount rates, and (5) estimates and assumptions used in the disclosure of commitments and contingencies. Changes in the assumptions could have a significant impact on results in future periods.

Industry Segment and Geographic Information

The Predecessor has evaluated how it is organized and managed and has identified one operating segment—the production and development of oil and natural gas. All of the Predecessor's assets are located in the United States, and all of its revenues are attributable to customers located in the United States.

Note 2—Significant Accounting Policies and Related Matters (Continued)

Fair Value Measurements

The Predecessor's financial instruments are measured at estimated fair value, and consist of derivative instruments, cash and cash equivalents, accounts payable and accrued expenses. The Predecessor's derivative instruments are measured at fair value on a recurring basis, see note 5 for further discussion. The carrying amounts of the Predecessor's other financial instruments are considered to be representative of their fair market value due to their short-term nature.

The Predecessor also applies fair value accounting guidance to measure nonfinancial assets and liabilities, such as the acquisition or impairment of proved oil and gas properties and the inception value of asset retirement obligations. These assets and liabilities are subject to fair value adjustments only in certain circumstances and are not subject to recurring revaluations. See note 6 for further discussion.

Cash and Cash Equivalents

The Predecessor considers all liquid investments purchased with an original maturity of three months or less to be cash equivalents. The Predecessor's cash balances held at commercial banks may at times exceed the Federal Deposit Insurance Corporation limit. The Predecessor has not experienced any credit losses to date.

Revenue Recognition

Oil and natural gas revenue is recognized when production is sold to a purchaser at a fixed and determinable price, delivery has occurred, title has transferred and the collectability of the revenue is probable. Oil and natural gas revenue is recorded using the sales method.

Accounts Receivable

The Predecessor's accounts receivable are generated primarily from the sale of oil and natural gas to various customers, from the billing of working interest partners for work on wells the Predecessor operates, and from derivative settlements receivable shortly after the balance sheet date. The Predecessor monitors the financial strength of its customers, partners, and counterparties. At December 31, 2015 and 2014, the Predecessor did not have any reserves for doubtful accounts and did not incur any bad debt expense in any period presented.

Derivative Instruments

The Predecessor uses commodity derivative instruments to manage its exposure to oil and natural gas price volatility. All of the commodity derivative instruments are utilized to manage price risk attributable to the Predecessor's expected oil and natural gas production, and the Predecessor does not enter into such instruments for speculative trading purposes. The Predecessor does not designate any derivative instruments as hedges for accounting purposes. The Predecessor records all derivative instruments on the balance sheet as either assets or liabilities measured at their estimated fair value. The Predecessor records gains and losses from the change in fair value of derivative instruments in

Note 2—Significant Accounting Policies and Related Matters (Continued)

current earnings as they occur. The Predecessor currently does not utilize any derivative instruments to manage exposure to variable interest rates, but may do so in the future.

The cash flow impact of the Predecessor's derivative activities is reflected as cash flows from operating activities. See note 5 for a more detailed discussion of the Predecessor's derivative activities.

Oil and Natural Gas Properties

Proved Oil and Natural Gas Properties

The Predecessor accounts for its oil and natural gas exploration and development costs using the successful efforts method. Under this method, all costs incurred related to the acquisition of oil and natural gas properties and the costs of drilling development wells and successful exploratory wells are capitalized, while the costs of unsuccessful exploratory wells are expensed if and when the well is determined not to have found reserves in commercial quantities. Other items charged to expense generally include geological and geophysical costs, delay rentals and lease and well operating costs.

Capitalized leasehold costs attributable to proved properties are depleted using the units-of-production method based on proved reserves on a field basis. Capitalized well costs, including asset retirement obligations (AROs), are depleted based on proved developed reserves on a field basis. For the years ended December 31, 2015 and 2014, the Predecessor recorded depletion for oil and natural gas properties of $22.2 million and $8.1 million, respectively.

Proved oil and natural gas properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying amount of such property. The Predecessor estimates the expected future cash flows of oil and natural gas properties and compares these undiscounted cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Predecessor will write down the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital expenditures and a commensurate discount rate. These assumptions and estimates represent Level 3 inputs, as further discussed in note 6. The Predecessor recorded no impairment of proved properties during the years ended December 31, 2015 and 2014.

Unproved Oil and Natural Gas Properties

Unproved oil and natural gas properties consist of costs to acquire undeveloped leases and unproved reserves, and are capitalized when incurred. When a successful well is drilled on undeveloped leasehold or reserves are otherwise attributable to a property, unproved property costs are transferred to proved properties. Unproved properties are periodically assessed for impairment on a property-by-property basis. The Predecessor evaluates significant unproved properties for impairment based on remaining lease term, drilling results, reservoir performance, seismic interpretation or future plans to develop acreage, and records impairment expense for any decline in value. The Predecessor

Note 2—Significant Accounting Policies and Related Matters (Continued)

recorded a $6.5 million and $1.4 million impairment of unproved properties for the years ended December 31, 2015 and 2014, respectively.

Oil and Natural Gas Reserves

The estimates of proved oil and natural gas reserves utilized in the preparation of the financial statements are estimated in accordance with the rules established by the Securities and Exchange Commission ("SEC") and the Financial Accounting Standards Board ("FASB"). The Predecessor's annual reserve estimates were prepared by third-party petroleum engineers. Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. It is possible that, because of changes in market conditions or the inherent imprecision of reserve estimates, the estimates of future cash inflows, future gross revenue, the amount of oil and natural gas reserves, the remaining estimated lives of oil and natural gas properties, or any combination of the above may be increased or reduced. Increases in recoverable economic volumes generally reduce per unit depletion rates while decreases in recoverable economic volumes generally increase per unit depletion rates. See note 12 for a more detailed discussion of the Predecessor's oil and natural gas reserves.

Other Property and Equipment

Other property and equipment includes equipment used in drilling and completion activities, the Predecessor's field office location, leasehold improvements, vehicles, IT hardware and software and office furniture, and is recorded at cost. Depreciation is recorded using the straight-line method over the estimated useful lives, which range from 2 to 20 years. When property and equipment is sold or retired, the capitalized costs and related accumulated depreciation are removed from the accounting records.

Unamortized Debt Issuance Costs

The Predecessor incurred legal and bank fees in connection with obtaining its senior secured revolving credit facility and incurs such fees when redetermining its borrowing base. These costs are stated at cost, net of amortization, which is computed using the straight-line method and recognized as interest expense in the Consolidated Statement of Operations.

Other Noncurrent Assets

Other noncurrent assets primarily consist of deposits paid for the Predecessor's office lease. As these amounts relate to a long-term lease, they are classified as noncurrent assets.

Deferred Rent

The Predecessor's office lease agreement contains scheduled escalation in lease payments during the term of the lease. In accordance with GAAP, the Predecessor records rent expense on a straight-line basis and a deferred rent liability for the difference between straight-line rent expense recorded and the actual amounts of the lease payments.

Note 2—Significant Accounting Policies and Related Matters (Continued)

Asset Retirement Obligations

The Predecessor's AROs relate to future costs associated with the plugging and abandonment of oil and natural gas wells, removal of equipment and facilities from leased acreage and restoration in accordance with local, state and federal laws. The discounted fair value of an ARO liability is required to be recognized in the period in which it is incurred, with the associated asset retirement capitalized in proved oil and gas property costs as part of the carrying cost of the oil and natural gas asset. The recognition of the ARO requires management to make numerous assumptions regarding such factors as the estimated probabilities, amounts and timing of settlements, credit-adjusted risk-free discount rates, inflation rates, and future advances in technology. In periods subsequent to the initial measurement of the ARO, the Predecessor recognizes period-to-period changes in the liability resulting from the passage of time and revisions to either the timing or the amount of the original estimate of undiscounted cash flows. Increases in the ARO liability due to the passage of time impact net earnings and accretion expense. The related capital cost, including revisions thereto, is charged to expense through accumulated depletion, depreciation and amortization.

The Predecessor recognizes an estimated liability for future costs associated with the abandonment of its oil and natural gas properties. A liability for the fair value of an ARO and corresponding increase to the carrying value of the related long-lived asset are recorded at the time a well is spud or acquired. The increase in carrying value is included in proved oil and gas properties in the accompanying balance sheet. The Predecessor depletes the amount added to proved oil and natural gas property costs and recognizes expense in connection with the accretion of the discounted liability over the remaining economic lives of the respective wells.

The Predecessor's AROs are included in its balance sheets within current and long-term liabilities. The changes in the Predecessor's AROs for the years ended December 31, 2015 and 2014 are as follows:

	2015	2014
	(in thousands)	
Beginning of period	$401	$ 10
Liabilities assumed	—	316
Liabilities incurred	64	50
Liabilities settled upon plugging and abandoning wells	(25)	—
Revisions of estimates(1)	125	—
Accretion expense	43	25
End of period	$608	$401

(1) The revision of estimates that occurred during the year ended December 31, 2015 is due to a change in the estimated timing for plugging and abandoning one well. The liability to complete the plugging and abandonment of this well is approximately $0.1 million at December 31, 2015 and is classified as a current liability, which is included in accrued liabilities on the Predecessor's December 31, 2015 Consolidated Balance Sheet.

Note 2—Significant Accounting Policies and Related Matters (Continued)

Income Taxes

The Predecessor is treated as a partnership for federal and state income tax purposes, with each partner taxed separately on its allocated share of the Predecessor's taxable income. Accordingly, the accompanying consolidated financial statements do not include a provision or liability for federal income taxes. The Predecessor's operations in Texas are subject to an entity-level tax, the Texas franchise tax, at a statutory rate of up to 1.0% of a portion of gross revenues apportioned to Texas. The Predecessor did not have taxable net income for purposes of calculating 2015 and 2014 Texas franchise tax, and did not have a franchise tax liability at December 31, 2015 or 2014.

In accordance with the provisions of Accounting Standards Codification 740, Income Taxes, the Predecessor found no uncertain tax positions and recorded no related liabilities as of December 31, 2015 and 2014. The Predecessor recognizes interest and penalties related to uncertain tax positions in income tax expense. As of December 31, 2015 and 2014, the Predecessor made no provision for interest or penalties related to uncertain tax positions. The Predecessor files income tax returns in the U.S. federal jurisdiction and various states. There are currently no federal or state income tax examinations underway, and tax returns for the years ended December 31, 2015 and 2014 are still open to examination.

Recent Accounting Pronouncements

In March 2016, the Financial Accounting Standards Board ("FASB") issued Accounting Standard Update ("ASU") 2016-09, "*Compensation—Stock Compensation Topic 718: Improvements to Employee Share-Based Payment Accounting*," which simplifies several aspects of the accounting for share-based payment award transactions. These simplifications include the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. ASU 2016-09 will be effective for reporting periods beginning on or after December 15, 2016, and early adoption is permitted. The Predecessor is currently evaluating the impact of its pending adoption of this guidance on its consolidated financial statements.

In February 2016, the FASB issued ASU 2016-02, "*Leases (Topic 842)*," which requires all lease transactions with terms in excess of 12 months to be recognized on the balance sheet as lease assets and lease liabilities. ASU 2016-02 becomes effective on January 1, 2019, and requires the use of the modified retrospective transition method. Although early application is permitted, the Predecessor does not intend to early adopt the new standard. The Predecessor is currently evaluating the impact of its pending adoption of this guidance on its consolidated financial statements.

In April 2015, the FASB issued ASU 2015-03, *Interest—Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs*. This ASU changes the presentation of debt issuance costs in the financial statements, and requires that debt issuance costs be presented in the balance sheet as a direct reduction from the carrying amount of the corresponding debt liability, consistent with debt discounts. As the guidance in this ASU did not address presentation or subsequent measurement of debt issuance costs related to line-of-credit arrangements, the FASB issued ASU 2015-15, *Interest—Imputation of Interest: Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements* in August 2015 to clarify that these presentation requirements did not apply to

Note 2—Significant Accounting Policies and Related Matters (Continued)

line-of-credit arrangements. ASU 2015-03 is effective for the annual periods beginning after December 15, 2016 and for interim periods within that annual period, and is required to be adopted retrospectively. ASU 2015-15 is effective upon adoption of ASU 2015-03. The Predecessor does not expect the adoption of these standards will have a material impact on its financial statements.

In May 2014, the Financial Accounting Standards Board (FASB) issued Accounting Standards Update (ASU), No. 2014-09, *Revenue from Contracts with Customers*, which replaces the majority of existing revenue recognition guidance in GAAP, including most industry specific guidance. ASU 2014-09 provides new guidance concerning recognition and measurement of revenue and requires additional disclosures about the nature, timing and uncertainty of revenue and cash flows arising from contracts with customers. ASU 2014-09 may be applied with a full retrospective approach or with a modified retrospective approach with the accumulated effect recognized at the date of initial application. ASU 2015-14 deferred the effective reporting periods of ASU 2014-09, and it is now effective for annual reporting periods beginning after December 15, 2018, and interim periods within annual reporting periods beginning after December 15, 2019. Early adoption of 2014-09 is permitted for annual periods beginning after December 15, 2016, including interim reporting periods therein. The Predecessor is currently evaluating which transition approach to use and the impact, if any, the adoption of this update will have on its consolidated financial statements and disclosures.

Note 3—Property and Equipment

Property and equipment includes the following (in thousands):

	December 31, 2015	December 31, 2014
Oil and natural gas properties:		
Proved oil and natural gas properties	$204,154	$ 96,590
Unproved oil and natural gas properties	128,913	125,703
Total oil and natural gas properties	333,067	222,293
Less: Accumulated depletion	(30,341)	(8,105)
Total oil and natural gas properties, net	302,726	214,188
Other property and equipment	2,491	2,422
Less: Accumulated depreciation	(828)	(422)
Total other property and equipment, net	1,663	2,000
Total property and equipment, net	$304,389	$216,188

Oil and natural gas properties are reviewed for impairment when facts and circumstances indicate their carrying value may not be recoverable. The Predecessor estimates the expected future cash flows of oil and natural gas properties and compares these undiscounted cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Predecessor will write down the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair

Note 3—Property and Equipment (Continued)

value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, cash flow from commodity hedges, estimated future capital expenditures and a commensurate discount rate. Unproved properties are assessed at least annually to determine whether they have been impaired and more frequently when industry conditions dictate an impairment may be possible. An impairment allowance is provided on an unproved property when the Predecessor determines that the property will not be developed.

For the year ended December 31, 2015, the Predecessor recorded an impairment of $6.5 million due to the decision by management to not develop or renew leases of undeveloped properties outside the Predecessor's three core operating areas. For the year ended December 31, 2014, the Predecessor recorded an impairment of $1.4 million due to the decision by management to not develop on renew leases of certain undeveloped properties. The Predecessor did not record dry hole expenses or impairments of proved properties in the years ended December 31, 2015 or 2014.

Note 4—Acquisitions and Disposals

During the year ended December 31, 2015, the Predecessor acquired approximately 11,900 net undeveloped acres for approximately $8.4 million through a series of transactions.

During the third quarter of 2015, the Predecessor sold 40 net undeveloped acres in the Whiskey River area for $0.1 million. During the first quarter of 2015, the Predecessor received $0.3 million in addition to the $2.9 million payment it received in October 2014 for the sale of on a portion of its interests in approximately 8,500 net undeveloped acres in northern Pecos County, Texas. This property was originally acquired as part of the Whiskey River Acquisition (defined below). The Predecessor did not record any gain or loss in conjunction with this transaction.

In September 2014, the Predecessor closed on the acquisition of working interests in three producing wells and approximately 8,500 net acres in Ward and Winkler counties in the Delaware Basin in West Texas (the Cochise Acquisition). The final adjusted purchase price of the Cochise Acquisition was $40.7 million The acquisition was accounted for using the acquisition method, which requires the acquired assets and liabilities to be recorded at fair values as of the acquisition date of September 23, 2014. As of December 31, 2014, the purchase price allocation is as follows (in thousands):

Consideration given:	
Cash	$40,688
Amount recognized for final fair value of assets acquired and liabilities assumed:	
Proved property	$ 6,243
Unproved property	34,482
Asset retirement obligation	(37)
Total fair value of oil and natural gas properties acquired	$40,688

The following unaudited pro forma financial information represents the combined results for the Predecessor and the Cochise Acquisition properties (exclusive of the Whiskey River properties) for the

Note 4—Acquisitions and Disposals (Continued)

years ended December 31, 2014, as if the Cochise Acquisition had occurred on January 1, 2014 (in thousands).

Revenue	$18,655
Net income	3,975

In March 2014, the Predecessor closed on an acquisition of working interests in 25 producing wells, one well waiting on completion and approximately 41,000 net acres in Ward, Reeves, and Pecos counties in the Delaware Basin in West Texas (the Whiskey River Acquisition). The final adjusted purchase price of the Whiskey River Acquisition was $76.1 million The acquisition was accounted for using the acquisition method, which requires the acquired assets and liabilities to be recorded at fair values as of the acquisition date of March 27, 2014. As of December 31, 2014, the purchase price allocation is as follows (in thousands):

Consideration given:	
Cash	$76,095
Amount recognized for final fair value of assets acquired and liabilities assumed:	
Proved property	$15,186
Unproved property	61,188
Asset retirement obligation	(279)
Total fair value of oil and natural gas properties acquired	$76,095

The following unaudited pro forma financial information represents the combined results for the Predecessor and the Whiskey River Acquisition properties (exclusive of the Cochise properties) for the years ended December 31, 2014, as if the Whiskey River Acquisition had occurred on January 1, 2014 (in thousands).

Revenue	$19,123
Net income	4,045

In addition to the acquisitions above, during the year ended December 31, 2014, the Predecessor acquired approximately 4,800 net undeveloped acres for approximately $11.0 million through a series of transactions.

Note 5—Commodity Derivative Instruments

The Predecessor hedges a portion of its crude oil sales using fixed price swap agreements based on futures price contracts for WTI crude oil. This exposes the Predecessor to market basis differential risk if the WTI price does not move in parity with the Predecessor's underlying sales of crude oil produced in the Delaware Basin of West Texas.

The Predecessor's derivative instruments are carried at fair value on the balance sheet. The Predecessor estimates the fair value using risk adjusted discounted cash flow calculations. Cash flows

Note 5—Commodity Derivative Instruments (Continued)

are based on published futures commodity price curves for the underlying commodity as of the date of the estimate. Due to the volatility of commodity prices, the estimated fair values of the Predecessor's derivative instruments are subject to fluctuation from period to period, which could result in significant differences between the current estimated fair value and the ultimate settlement price. Refer to note 6.

At December 31, 2015, the Predecessor was not party to any commodity derivatives for future periods. However, the Predecessor will enter into derivative contracts it views as favorable, and may enter into commodity derivative transactions in the future.

As the Predecessor does not apply hedge accounting, its earnings are affected by the use of the mark-to-market method of accounting for derivative financial instruments. The changes in fair value of these instruments are recognized through earnings as other income or expense rather than deferred until the anticipated transaction affects earnings. The use of mark-to-market accounting for financial instruments can cause noncash earnings volatility due to changes in the underlying commodity price indices. The ultimate gain or loss upon settlement of these transactions is recognized in earnings as other income or expense.

The Predecessor does not aggregate the fair value of its derivative instruments, but records the fair value of each individual derivative contract on the balance sheet as a current or noncurrent asset or liability.

The Predecessor recognized the following gains in earnings for the years ended December 31, 2015 and 2014:

	2015	2014
	(in thousands)	
Beginning fair value of commodity derivatives	$ 4,612	$ —
Gain on commodity derivatives(1)	1,323	5,375
Commodity derivative cash settlements received	(5,935)	(763)
Ending fair value of commodity derivatives	$ —	$4,612

(1) Realized and unrealized gains on commodity derivatives are recorded in the Other Income (Expense) section of the Consolidated Statement of Operations.

Commodity Price Risk

The Predecessor's principal market risks are its exposure to changes in commodity prices, particularly to the prices of oil and natural gas. The prices of oil and natural gas are subject to market fluctuations in response to changes in supply, demand, market uncertainty and a variety of additional factors beyond the Predecessor's control. The Predecessor monitors these risks and enters into commodity derivative transactions designed to mitigate the impact of commodity price fluctuations on its business.

In an effort to reduce the variability of the Predecessor's cash flows, the Predecessor hedged the commodity prices associated with a portion of its expected oil volumes through year-end 2015 by

Note 5—Commodity Derivative Instruments (Continued)

entering into swap and collar derivative financial instruments. With swaps, the Predecessor typically receives an agreed upon fixed price for a specified notional quantity of oil or natural gas, and the Predecessor pays the hedge counterparty a floating price for that same quantity based upon published index prices. With collars, the Predecessor enters into a purchased put, which establishes a price floor, and a sold call, which establishes a price ceiling. The Predecessor's commodity derivatives may expose it to the risk of financial loss in certain circumstances. The Predecessor's derivative arrangements provide protection on the hedged volumes if market prices decline below the prices at which these derivatives are set. If market prices rise above the prices at which the Predecessor has hedged, the Predecessor will receive less revenue on the hedged volumes than it would receive in the absence of hedges.

Derivative Counterparty Risk

Where the Predecessor is exposed to credit risk in its financial instrument transactions, management analyzes the counterparty's financial condition prior to entering into an agreement, establishes credit limits and monitors the appropriateness of these limits on an ongoing basis. Generally, the Predecessor does not require collateral and does not anticipate nonperformance by its counterparties.

The Predecessor's counterparty credit exposure related to commodity derivative instruments is represented by the fair value of contracts with a net positive fair value at the reporting date. These outstanding instruments expose the Predecessor to credit risk in the event of nonperformance by the counterparties to the agreements. Should the creditworthiness of the Predecessor's counterparties decline, its ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party. In the event of a counterparty default, the Predecessor may sustain a loss and its cash receipts could be negatively impacted.

At December 31, 2014 and during 2015, one counterparty accounted for all the Predecessor's counterparty credit exposure related to commodity derivative assets. This counterparty possesses investment grade credit ratings based upon minimum credit ratings assigned by Standard & Poor's Ratings Services. The Predecessor did not have any derivative positions at December 31, 2015.

Note 6—Fair Value Measurements

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). The authoritative guidance requires disclosure of the framework for measuring fair value of financial and nonfinancial assets and liabilities. Financial assets and liabilities are measured at fair value on a recurring basis. Nonfinancial assets and liabilities, such as the initial measurement of asset retirement obligations and proved oil and natural gas properties upon acquisition or impairment, are recognized at fair value on a nonrecurring basis.

Note 6—Fair Value Measurements (Continued)

The Predecessor categorizes the inputs to the fair value of its financial assets and liabilities using a three-tier fair value hierarchy that prioritizes the significant inputs used in measuring fair value:

Level 1—Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives, listed securities and U.S. government treasury securities.

Level 2—Pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry standard models that consider various assumptions, including quoted prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in the category include nonexchange-traded derivatives such as over-the-counter forwards, swaps and options.

Level 3—Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value, and the Predecessor does not have sufficient corroborating market evidence to support classifying these assets and liabilities as Level 2.

The following tables set forth, by level within the fair value hierarchy, the Predecessor's financial assets and liabilities measured at fair value on a recurring basis as of December 31, 2014. These financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. The Predecessor's assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

	Total	Level 1	Level 2	Level 3
		(in thousands)		
December 31, 2014:				
Assets from commodity derivative contracts	$4,612	$—	$4,612	$—
Liabilities from commodity derivative contracts	—	—	—	—

Fair Value of Other Financial Instruments

The carrying values of items comprising current assets and current liabilities approximate fair value due to the short-term maturities of these instruments.

Note 6—Fair Value Measurements (Continued)

Assets and Liabilities Measured on a Nonrecurring Basis

The Cochise and Whiskey River Acquisitions discussed in note 4 qualify as business combinations and, as such, the Predecessor estimated the fair value of each property as of each acquisition date. The Predecessor used a discounted cash flow model based on an income approach and made market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. Given the unobservable nature of the inputs, nonrecurring measurements of business combinations are deemed to be classified within Level 3 inputs.

The Predecessor reviews its proved and unproved oil and natural gas properties for impairment whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. The Predecessor's analysis takes into account several factors, including future cash flows, the determination of the values of any possible or probable reserves, and, if applicable, appropriate risk-weighting discounts, all of which would be classified within Level 3.

Additionally, the Predecessor uses fair value to determine the inception value of its AROs. The inputs used to determine such fair value are based primarily on the present value of estimated future cash inflows and outflows. Given the unobservable nature of these inputs, they are generally classified within Level 3.

Note 7—Debt Obligations

On June 19, 2015, the Predecessor entered into a credit agreement which provided for a $500.0 million five-year senior secured revolving credit facility that matures on June 19, 2020 (credit facility). The credit facility had an initial borrowing base of $20.0 million and has two scheduled borrowing base redeterminations per year. The Predecessor has the option to request up to two additional redeterminations per year between October 1, 2015 and October 1, 2017. The borrowing base increased to $25.0 million on July 23, 2015 and increased to $35.0 million on October 10, 2015. Future borrowing bases will be computed based on proved oil and natural gas reserves, hedge positions and estimated future cash flow from those reserves, as well as any other outstanding debt.

Borrowings under the credit facility bear interest at the greatest of (a) the prime rate in effect plus an applicable margin, (b) the federal funds rate in effect plus one half of 1.0%, or (c) the daily London Interbank Offered Rate (LIBOR), plus an applicable margin. The applicable margins associated with the prime rate or the federal funds rate vary based on the utilization percentage of the credit facility, and are 0.5% to 1.5% for base rate loans and 1.5% to 2.5% for LIBOR loans. The Predecessor also pays an annual commitment fee based on the unused portion of the outstanding borrowing base. The commitment fee rate is either 0.375% or 0.500%, depending on the utilization percentage of the credit facility. The weighted average interest rate on the Predecessor's credit facility was 2.097% during 2015.

The credit facility is secured by oil and natural gas properties representing at least 80% of the value of the Predecessor's proved reserves. The credit facility contains certain covenants, including among others, restrictions on indebtedness, restrictions on liens, restrictions on investments, restrictions

Note 7—Debt Obligations (Continued)

on mergers, restrictions on sales of assets, restrictions on dividends and payments to the Predecessor's capital interest holders, and restrictions on the Predecessor's hedging activity. The financial covenants require the Predecessor to maintain a current ratio (as defined) of at least 1.0 to 1.0, a minimum interest coverage ratio (as defined) of at least 2.5 to 1.0 and a leverage ratio (as defined) not greater than 4.0 to 1.0. The financial covenants are measured on a quarterly basis, with the minimum interest coverage ratio and leverage ratio beginning in the second quarter of 2015 and the current ratio beginning in the second quarter of 2016. As of December 31, 2015, the Predecessor was in compliance with its financial covenants.

As of December 31, 2015, the Predecessor had a $35.0 million borrowing base with $20.0 million outstanding and $15.0 million available on the credit facility. The Predecessor capitalized $0.03 million of interest during 2015. The Predecessor did not capitalize any interest during 2016.

Note 8—Members' Equity

Capital Interests

The Predecessor is a limited liability company with capital interests owned by Quantum and the officers of the Predecessor. The total capital commitment from all Jagged Peak Energy LLC capital members is $405.9 million, with Quantum representing 98.55% of the total capital commitment. Capital interests in the Predecessor consist of a single class of units, which receive an internal rate of return threshold of 8% prior to distributions to any other class of equity interests.

Contributions

Capital calls approved by the board of directors are funded on a pro rata basis by all of the capital members. During the years ended December 31, 2015 and 2014, the Predecessor received $51.0 million and $199.8 million, respectively, of capital contributions from its capital members to fund acquisitions and operations.

As of December 31, 2015, the Predecessor had remaining capital commitments of approximately $111.3 million.

Distributions

The Predecessor did not make any distributions of capital during the years ended December 31, 2015 and 2014.

Management Incentive Units

The Predecessor has established an Incentive Pool Plan, whereby the Predecessor may grant Management Incentive Units ("MIUs") to employees or selected other participants. The MIUs are considered "profits interests" that participate in certain distribution events (only after certain return thresholds are achieved by the capital interests) following a qualifying initial public offering, sale, merger, or other qualifying transaction involving the stock or assets of the Predecessor. The MIUs have no voting rights and partially vest over four years with the remainder vesting upon a liquidation event.

Note 8—Members' Equity (Continued)

Vested units will be forfeited if an incentive unit holder's employment is terminated for cause or if the unit holder terminates his or her employment. Compensation expense for the MIUs will be recognized when all performance, market and service conditions are probable of being satisfied, which is generally upon a liquidation event or initial public offering ("Vesting Event"). As of December 31, 2015 and 2014, the Predecessor had issued 2,350,000 and 2,272,500 MIUs, respectively, from the total pool of 2,600,000 authorized MIUs.

MIUs vest 18.75% each year for four years, with the remaining 25% vesting upon a Vesting Event. All MIUs, whether vested or not, vest upon and participate in a Vesting Event. The Predecessor has the right, but not the obligation, to repurchase MIUs if employment is terminated. If the repurchase price cannot be mutually agreed to among the MIU holder and the Predecessor, the amount will be at the fair market value as determined by a third party valuation specialist.

Note 9—Employee Benefit Plans

The Predecessor sponsors a 401(k) defined contribution plan under which it makes matching contributions for participating employees based on a percentage of the employee contributions. Matching contributions totaled approximately $0.2 million during each of the years ended December 31, 2015 and 2014. Benefits under this plan are equally available to all employees, and employees are fully vested in the employer contribution upon receipt.

Note 10—Commitments and Contingencies

Legal Matters

In the ordinary course of business, the Predecessor may at times be subject to claims and legal actions. Management believes it is remote that the impact of such matters will have a material adverse effect on the Predecessor's financial position, results of operations or cash flows.

Environmental Matters

The Predecessor accounts for environmental contingencies in accordance with the accounting guidance related to accounting for contingencies. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation, are expensed.

Liabilities are recorded when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. At both December 31, 2015 and December 31, 2014, the Predecessor had no environmental matters requiring specific disclosure or requiring the recognition of a liability.

Note 10—Commitments and Contingencies (Continued)

Contractual Obligations

The Predecessor leases its corporate office space in Denver, Colorado under an agreement expiring in 2018. The Predecessor also finances certain office equipment under operating leases, which expire over the next two years. For each of the years ended December 31, 2015 and 2014, rent expense with respect to these lease commitments was approximately $0.6 million. As of December 31, 2015, the Predecessor had one drilling rig under contract. This rig can be released after January 5, 2016 without penalty if a 90-day notice is given. The contract for this rig was renewed for one year starting February 13, 2016. If this rig is cancelled within the first six months of the contract, the Predecessor will be required to pay an early termination fee of up to $0.2 million. After the first six months of the contract, the Predecessor may terminate without penalty if a 30-day notice is given.

As of December 31, 2014, the Predecessor had two drilling rigs under contract. The Predecessor gave notice of termination of one of the rig contracts in early February 2015 and discontinued its use of the rig in early March 2015. Pursuant to the contract terms as of the time the rig was released, the Predecessor paid an early termination fee of $0.25 million, which is reflected as other operating costs in the Consolidated Statements of Operations.

The table below shows the Predecessor's future minimum payments under noncancelable operating leases and other commitments as of December 31, 2015:

	Total	2016	2017	2018	2019	2020
	(in thousands)					
Operating leases(1)	$1,965	$ 737	$703	$525	$—	$—
Service and purchase contracts(2)	1,057	1,057	—	—	—	—
Rig contracts	240	240	—	—	—	—
Total	$3,262	$2,034	$703	$525	$—	$—

(1) Primarily relates to the lease of the Predecessor's corporate offices

(2) Primarily relates to obligation to purchase LACT units in conjunction with oil gathering for current and future wells

Note 11—Related Party Transactions

Quantum owns significant capital interests in the Predecessor, a 41.5% interest in Oryx Midstream Services, LLC (together with Oryx Southern Delaware Holdings, LLC, Oryx), a 61% interest in Phoenix Lease Services, LLC (Phoenix) and an indirect interest in Trident Water Services, LLC (Trident), a wholly owned subsidiary of Phoenix.

During the year ended December 31, 2015, the Predecessor paid aggregate fees of $1.0 million, $0.4 million and $0.4 million to Trident, Phoenix and Oryx, respectively. During the year ended December 31, 2014, the Predecessor paid aggregate fees of $0.3 million and $0.2 million to Trident and Phoenix, respectively.

Note 11—Related Party Transactions (Continued)

Trident provides the Predecessor water transfer services and Phoenix rents certain equipment to the Predecessor. The Predecessor is under no obligation to use either provider, and both provide services only when selected as a vendor in the Predecessor's normal bidding process. Oryx provides the Predecessor crude oil gathering services and sells us related equipment and maintenance services. The crude oil gathering services provided by Oryx are pursuant to a 12-year crude oil gathering agreement.

Note 12—Supplemental Oil and Natural Gas Disclosures (Unaudited)

Costs Incurred for Oil and Natural Gas Producing Activities

Net capitalized costs related to the Predecessor's oil and natural gas producing activities at December 31, 2015 and 2014 were as follows:

	2015	2014
	(in thousands)	
Acquisition costs:		
Proved property	$ —	$ 21,431
Unproved property	11,437	103,355
Development costs	115,492	73,829
Exploration costs	852	64
Total costs incurred	$127,781	$198,679

Oil and Natural Gas Reserve Quantities

The reserve information presented below is based on estimates of net proved reserves as of December 31, 2015 and 2014 that were prepared by the Predecessor's independent petroleum engineering firm Ryder Scott Company, LP in accordance with guidelines established by the SEC.

Proved oil and gas reserves are the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions (i.e., prices and costs as of the date the estimate is made). Proved developed oil and gas reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods. A variety of methodoligies are used to determine our proved reserve estimates. The primary methodologies used are decline curve analysis, advance production type curve matching, petro physics/log analysis and analogy. Some combination of these methods is used to determine reserve estimates across substantially all our properties. Reserve estimates are inherently imprecise, and estimates of undeveloped locations are more imprecise than estimates of established proved producing locations. Accordingly, our reserve estimates are expected to change as future information becomes available. The Predecessor's proved reserves are located entirely within the United States.

Proved oil and natural gas reserves were calculated based on the prices for oil and natural gas during the 12-month period before the reporting date, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period. This average price is also used in

Note 12—Supplemental Oil and Natural Gas Disclosures (Unaudited) (Continued)

calculating the aggregate amount and changes in future cash inflows related to the standardized measure of discounted future cash flows. In addition, the SEC generally requires that reserves classified as proved undeveloped be capable of conversion into proved developed within five years of classification unless specific circumstances justify a longer time. The Predecessor's development plans at December 31, 2015 related to scheduled drilling over the next five years are subject to many uncertainties and variables, including availability of capital, future oil and natural gas prices, cash flows from operations, future drilling costs, demand for oil and natural gas and other economic factors. See "Business—Oil and Natural Gas Data—Proved Reserves—Summary of Reserves" for additional information regarding the Predecessor's proved developed reserves and PUD development.

The following table sets forth information regarding the Predecessor's estimated net total proved and proved developed oil and gas reserve quantities:

	Oil (MBbls)	Gas (MMcf)	Liquids (MBbls)	Total (MBoe)
Proved reserves:				
Balance December 31, 2013	—	—	—	—
Acquisitions of reserves	837	707	109	1,064
Extensions, discoveries and other additions	1,270	1,094	291	1,744
Revisions of previous estimates	—	—	—	—
Sales of reserves	—	—	—	—
Production	(189)	(172)	(35)	(253)
Balance December 31, 2014	1,918	1,629	365	2,555
Acquisitions of reserves	—	—	—	—
Extensions, discoveries and other additions	8,734	4,906	1,226	10,778
Revisions of previous estimates	559	26	(11)	552
Sales of reserves	—	—	—	—
Production	(718)	(404)	(89)	(874)
Balance December 31, 2015	10,493	6,157	1,491	13,011
Proved developed reserves:				
December 31, 2013	—	—	—	—
December 31, 2014	1,529	1,319	288	2,037
December 31, 2015	4,848	2,547	621	5,894
Proved undeveloped reserves:				
December 31, 2013	—	—	—	—
December 31, 2014	389	310	77	518
December 31, 2015	5,645	3,610	870	7,117

Estimated proved reserves at December 31, 2015 were 13.0 MMBoe, compared to 2.6 MMBoe at December 31, 2014. The increase in proved reserves during 2015 was primarily related to the Predecessor's drilling activities. During 2015, the Predecessor drilled and completed seven wells and added nine PUD locations, leading to a combined increase of 10.8 MMBoe of extensions and

Note 12—Supplemental Oil and Natural Gas Disclosures (Unaudited) (Continued)

discoveries. The Predecessor also had 0.6 MMBoe of upward revisions of prior reserve estimates due to increased performance from the Predecessor's wells, partially offset by negative impacts from the decline in average oil and natural gas pricing between periods.

Estimated proved reserves at December 31, 2014 were 2.6 MMBoe, and at December 31, 2013, the Predecessor had not yet recorded proved reserves. The proved reserve quantities for the year ended December 31, 2014 were partly due to the Predecessor's acquisition of 28 producing wells in two separate transactions (see Note 4 to the Consolidated Financial Statements) and partly due to the Predecessor's operated drilling program. The Predecessor completed an additional 5 wells during 2014, 4 of which were drilled by the Predecessor, which added 1.1 MMBOE of proved developed reserves. The Predecessor also added an additional 0.6 MMBOE from one PUD location added during 2014.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure is calculated using pricing required by the SEC, as explained above, using NYMEX WTI posted prices for oil and natural gas liquids and NYMEX Henry Hub prices for natural gas. For the years ended December 31, 2015 and 2014, benchmark prices used were SEC prices of $50.28 per Bbl and $94.99 per Bbl, respectively, for oil and $2.58 per MMBtu and $4.35 per MMBtu, respectively, for natural gas. For oil and natural gas liquids volumes, the benchmark WTI posted price is adjusted for quality, transportation fees and regional price differentials. For gas volumes, the Henry Hub spot price is adjusted for energy content, transportation fees and regional price differentials.

The assumptions used to calculate estimated future cash inflows do not necessarily reflect the Predecessor's expectations of actual revenues or costs, nor their present worth. In addition, variations from the expected production rate also could result directly or indirectly from factors outside of the Predecessor's control, such as unexpected delays in development, changes in prices or regulatory or environmental policies. The reserve valuation further assumes that all reserves will be disposed of by production. If reserves are sold in place, additional economic considerations could also affect the amount of cash eventually realized.

Future development and production costs are calculated by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at the end of the year, based on year-end costs and assuming continuation of existing economic conditions.

A 10% annual discount rate was used to reflect the timing of the future net cash flows relating to proved oil and gas reserves. As a limited liability company, the Predecessor is a pass through entity for tax purposes. The effect of future net income taxes has been excluded from the standardized measure of discounted future net cash flows as the Predecessor is not subject to federal income taxes. The Predecessor is, however, subject to the Texas franchise tax, which is an entity-level tax at a statutory rate of up to 1.0% of a portion of gross revenue apportioned to Texas.

Note 12—Supplemental Oil and Natural Gas Disclosures (Unaudited) (Continued)

The following table presents the standardized measure of discounted net cash flows related to proved oil and gas reserves for the periods indicated:

	Year ended December 31,	
	2015	2014
	(in thousands)	
Future cash inflows	$ 524,538	$180,425
Future production costs	(146,779)	(53,560)
Future development costs	(90,661)	(9,519)
Future tax expense	(3,467)	(1,201)
Future net cash flows	283,631	116,145
10% annual discount	(151,910)	(51,279)
Standardized measure of discounted future net cash flows	$ 131,721	$ 64,866

The present value (at a 10% annual discount) of future net cash flows from the Predecessor's proved reserves is not necessarily the same as the current market value of its estimated oil and natural gas reserves. The Predecessor bases the estimated discounted future net cash flows from its proved reserves on prices and costs in effect on the day of estimate in accordance with the applicable accounting guidance. Actual future net cash flows from the Predecessor's oil and natural gas properties will also be affected by factors such as actual prices the Predecessor receives for oil and natural gas, the amount and timing of actual production, supply of and demand for oil and natural gas and changes in governmental regulations or taxation.

The timing of both the Predecessor's production and incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing of actual future net cash flows from proved reserves, and thus their actual present value. In addition, the 10% annual discount factor the Predecessor uses when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with the Predecessor or the oil and natural gas industry in general.

Note 12—Supplemental Oil and Natural Gas Disclosures (Unaudited) (Continued)

A summary of changes in the standardized measure of discounted future net cash flows is as follows:

	Year ended December 31,	
	2015	2014
	(in thousands)	
Standardized measure of discounted future net cash flows, beginning of period	$ 64,866	$ —
Sales of oil and natural gas, net of production costs and taxes	(28,264)	(13,197)
Extensions, discoveries and improved recovery, less related costs	118,532	51,089
Revisions of previous quantity estimates	5,187	—
Net changes in prices and production costs	(41,264)	—
Previously estimated development costs incurred during the period	34	—
Changes in estimated future development costs	1,898	—
Accretion of discount	6,552	—
Acquisitions of reserves	—	27,626
Sales of reserves	—	—
Net change in taxes	(1,042)	(652)
Changes in production rates (timing) and other	5,222	—
Standardized measure of discounted future net cash flows, end of period	$131,721	$ 64,866

Note 13—Subsequent Events

On March 25, 2016, the Predecessor and certain MIU holders employed by the Predecessor on April 1, 2016 (“MIU advance recipients”) entered into the First Amendment to the Limited Liability Company Agreement (the “Distribution Agreement”) under which the Predecessor made a $14.7 million cash advance to MIU advance recipients during April 2016. Under the terms of the Distribution Agreement, the distribution will be treated as an advance and will dollar for dollar offset distributions otherwise payable to MIU advance recipients.

On July 20, 2016, the Predecessor acquired, from an unrelated third party, certain oil and gas properties located in Ward County, Texas for approximately $6.3 million in cash. Additional post-closing adjustments may be required.

The Predecessor entered into two drilling rig contracts, effective July 1, 2016 and August 1, 2016, respectively. Each drilling rig contract’s term ends December 31, 2017. These contracts can be terminated at any time provided the Predecessor pays a demobilization fee of $0.1 million and a daily rate of approximately $12,000 for up to 90 days after giving notice of termination.

On September 30, 2016, the Predecessor entered into a third amendment to its credit facility. The borrowing base was increased to $160 million. Total fees paid for the September borrowing base increase were $0.3 million and will be amortized over the remaining term of the credit facility. As of September 30, 2016, outstanding borrowings under the credit facility were $90 million.

JAGGED PEAK ENERGY LLC

(PREDECESSOR)

CONDENSED CONSOLIDATED BALANCE SHEETS

(Unaudited)

(in thousands)

	September 30, 2016	December 31, 2015
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 5,420	$ 14,165
Accounts receivable	7,818	8,005
Commodity derivative assets	201	—
Other current assets	2,416	504
Total current assets	15,855	22,674
PROPERTY, PLANT AND EQUIPMENT		
Oil and natural gas properties, successful efforts method	460,569	333,067
Accumulated depreciation, depletion and amortization	(58,984)	(30,341)
Total oil and gas properties	401,585	302,726
Other property and equipment, net	2,921	1,663
Total property, plant and equipment	404,506	304,389
NONCURRENT ASSETS		
Unamortized debt issuance costs	1,408	542
Commodity derivative assets	39	—
Other assets	14,828	127
Total other assets	16,275	669
TOTAL ASSETS	$436,636	$327,732
LIABILITIES AND MEMBERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	$ 7,055	$ 2,452
Accrued liabilities	23,715	20,171
Commodity derivative liabilities	4,860	—
Total current liabilities	35,630	22,623
LONG-TERM LIABILITIES		
Senior secured revolving credit facility	90,000	20,000
Commodity derivative liabilities	2,429	—
Asset retirement obligations	380	490
Other long-term liabilities	167	289
Total non-current liabilities	92,976	20,779
MEMBERS' EQUITY		
Common units	326,098	294,556
Accumulated defecit	(18,068)	(10,226)
Total members' equity	308,030	284,330
TOTAL LIABILITIES AND MEMBERS' EQUITY	$436,636	$327,732

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

JAGGED PEAK ENERGY LLC

(PREDECESSOR)

CONDENSED CONSOLIDATED STATEMENTS OF OPERATIONS

(Unaudited)

(in thousands)

	Nine Months Ended September 30,	
	2016	**2015**
REVENUES		
Oil sales	$47,215	$21,445
Natural gas sales	1,450	690
NGL sales	2,023	848
Other operating revenues	693	10
Total revenues	51,381	22,993
OPERATING EXPENSES		
Lease operating expenses	5,221	2,357
Gathering and transportation expenses	662	98
Production and ad valorem taxes	3,173	1,588
Depletion, depreciation, amortization and accretion	29,430	14,488
Impairment of oil and natural gas properties and dry hole cost	1,509	7
Other operating expenses	1,671	257
General and administrative	7,878	5,906
Total operating expenses	49,544	24,701
INCOME (LOSS) FROM OPERATIONS	1,837	(1,708)
OTHER INCOME(EXPENSE)		
(Loss) gain on commodity derivatives	(8,208)	1,086
Interest expense and other	(1,471)	(77)
Total other (expense) income	(9,679)	1,009
NET LOSS	$(7,842)	$ (699)

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

JAGGED PEAK ENERGY LLC

(PREDECESSOR)

CONDENSED CONSOLIDATED STATEMENTS OF MEMBERS' EQUITY

(Unaudited)

(in thousands)

	Common Units	Accumulated Defecit	Total Members' Equity
BALANCE AT DECEMBER 31, 2015	$294,556	$(10,226)	$284,330
Capital contributions	31,542	—	31,542
Net loss	—	(7,842)	(7,842)
BALANCE AT SEPTEMBER 30, 2016	$326,098	$(18,068)	$308,030

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

JAGGED PEAK ENERGY LLC

(PREDECESSOR)

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

(Unaudited)

(in thousands)

	Nine Months Ended September 30,	
	2016	**2015**
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net loss	$ (7,842)	$ (699)
Adjustments to reconcile net loss to net cash provided by operating activities:		
Depletion, depreciation, amortization and accretion	29,430	14,488
Management incentive advance	(14,712)	—
Impairment of oil and natural gas properties and dry hole cost	1,509	7
Amortization of debt issuance costs	164	30
Loss (gain) on derivative assets	8,208	(1,086)
Net cash (payments) receipts on settled derivatives	(1,159)	4,127
Other	(120)	(116)
Change in operating assets and liabilities:		
Accounts receivable and other current assets	(735)	(3,933)
Other assets	11	22
Accounts payable and accrued liabilities	1,878	(935)
Net cash used in operating activities	16,632	11,905
CASH FLOWS FROM INVESTING ACTIVITIES:		
Development of oil and natural gas properties	(84,809)	(72,198)
Leasehold and acquisition costs	(39,344)	(8,356)
Other capital expenditures	(1,831)	(204)
Proceeds from sale of oil and natural gas properties	—	440
Net cash used in investing activities	(125,984)	(80,318)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Proceeds from revolving credit facility	70,000	10,000
Proceeds from common units issued	31,542	38,000
Deferred offering costs	95	
Debt issuance costs	(1,030)	(552)
Net cash provided by financing activities	100,607	47,448
NET CHANGE IN CASH AND CASH EQUIVALENTS	(8,745)	(20,965)
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD	14,165	33,628
CASH AND CASH EQUIVALENTS, END OF PERIOD	$ 5,420	$ 12,663
SUPPLEMENTAL DISCLOSURES OF CASH FLOW INFORMATION:		
Interest paid, net of capitalized interest	$ 1,189	$ 53
Cash paid for income taxes	—	—
SUPPLEMENTAL DISCLOSURES OF NONCASH ACTIVITY:		
Asset retirement obligations	$ (165)	$ 43
Accrued capital expenditures	22,906	16,426
Accrued deferred offering costs	1,086	—

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

JAGGED PEAK ENERGY LLC

(PREDECESSOR)

Notes to Condensed Consolidated Financial Statements

September 30, 2016

(Unaudited)

Note 1—Organization, Operations and Basis of Presentation

Organization and Operations

Jagged Peak Energy LLC (together with its subsidiaries, the "Predecessor"), a Delaware limited liability company, is a growth-oriented, independent oil and natural gas company focused on the acquisition and development of unconventional oil and associated liquids-rich natural gas reserves in the Delaware Basin, a sub-basin of the Permian Basin of West Texas. The Predecessor's acreage is located on large, contiguous blocks in the adjacent counties of Winkler, Ward, Reeves and Pecos, with significant oil-in-place within multiple stacked hydrocarbon-bearing formations. The Predecessor was formed by an affiliate of Quantum Energy Partners ("Quantum"), a leading energy private equity firm, and key members of the Predecessor's management team.

On September 20, 2016, the Predecessor formed Jagged Peak Energy Inc. (the "Company"), a Delaware corporation, as its wholly owned subsidiary. The Company was formed to become the holding company of the Predecessor in connection with the Company's initial public offering ("IPO"). The Company has no prior operating activities.

Pursuant to the terms of a corporate reorganization (the "Corporate Reorganization") that will be completed prior to the closing of the IPO, the Company will acquire, directly or indirectly, all of the membership interests in the Predecessor in exchange for the issuance to the Predecessor's existing owners of all of the Company's issued and outstanding shares of common stock (prior to the issuance of shares of common stock in the IPO). As a result of these transactions, the Predecessor will become the Company's direct, wholly owned subsidiary.

Basis of Presentation

The accompanying unaudited condensed consolidated financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP"). They reflect all adjustments that are, in the opinion of management, necessary for a fair statement of results of the interim periods, on a basis consistent with the audited annual financial statements. In the opinion of management, all adjustments, consisting of normal recurring accruals considered necessary for a fair presentation of interim financial information, have been included. Operating results for the periods presented are not necessarily indicative of expected results for the full year. Certain prior period amounts have been reclassified to conform to the current presentation on the accompanying unaudited condensed consolidated financial statements.

Note 2—Significant Accounting Policies and Related Matters

Significant Accounting Policies

Deferred Offering Costs. In conjunction with a possible IPO or Corporate Reorganization, incremental costs directly related to the IPO are capitalized as deferred offering costs within other current assets until the common shares are issued or the potential offering is terminated. Upon issuance of common shares, these costs will be offset against the proceeds received. If the IPO does not occur, they will be expensed.

Note 2—Significant Accounting Policies and Related Matters (Continued)

The preparation of financial statements in conformity with GAAP requires management to make certain estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of net sales and expenses during the reporting periods. Actual results could differ from those estimates. For a complete description of the Predecessor's significant accounting policies, recent accounting pronouncements and critical estimates, see "Note 1—Organization, Operations and Basis of Presentation" in the Predecessor's consolidated financial statements for the year ended December 31, 2015.

Note 3—Acquisitions and Divestitures

July 20, 2016 Oil and Natural Gas Property Acquisition

On July 20, 2016, the Predecessor acquired, from an unrelated third party, certain oil and gas properties located in Ward County, Texas for an adjusted purchase price of approximately $6.2 million. The acquisition contributed $0.3 million of revenue to the Predecessor for the nine months ended September 30, 2016. The acquisition was accounted for using the acquisition method under Accounting Standards Codification ("ASC") Topic 805, "*Business Combinations,*" which requires the acquired assets and liabilities to be recorded at fair values as of the acquisition date.

The following table summarizes the preliminary purchase price and the preliminary estimated values of assets acquired and liabilities assumed (in thousands):

Preliminary purchase price:		
Cash		$6,206
Total consideration given		$6,206
Preliminary fair value allocation of purchase price:		
Oil and natural gas properties:		
Proved properties	$6,220	
Unproved properties	—	
Total oil and natural gas properties		$6,220
Asset retirement obligation assumed		(14)
Total consideration and fair value		$6,206

The following unaudited pro forma financial information represents the combined results for the Predecessor and the properties acquired for the nine months ended September 30, 2016 and 2015 as if the acquisition had occurred on January 1, 2015. The following pro forma results include the operating

Note 3—Acquisitions and Divestitures (Continued)

revenues and net income for the acquired properties for the nine months ended September 30, 2016 and 2015 (in thousands):

	Nine Months Ended September 30,	
	2016	2015
Operating revenues	$51,515	$24,753
Net income	$(7,465)	$ 482

Note 4—Property and Equipment

The Predecessor accounts for its oil and natural gas exploration and development costs using the successful efforts method. Under this method, all costs incurred related to the acquisition of oil and natural gas properties and the costs of drilling development wells and successful exploratory wells are capitalized, while the costs of unsuccessful exploratory wells are expensed if and when the well is determined not to have found reserves in commercial quantities. Other items charged to expense generally include geological and geophysical costs, delay rentals and lease and well operating costs. Property and equipment includes the following (in thousands):

	September 30, 2016	December 31, 2015
Oil and natural gas properties:		
Proved oil and natural gas properties	$314,383	$204,154
Unproved oil and natural gas properties	146,186	128,913
Total oil and natural gas properties	460,569	333,067
Less: Accumulated depletion	(58,984)	(30,341)
Total oil and natural gas properties, net	401,585	302,726
Other property and equipment	4,330	2,491
Less: Accumulated depreciation	(1,409)	(828)
Total other property and equipment, net	2,921	1,663
Total property, plant and equipment, net	$404,506	$304,389

Oil and natural gas properties are reviewed for impairment when facts and circumstances indicate their carrying value may not be recoverable. The Predecessor estimates the expected future cash flows of oil and natural gas properties and compares these undiscounted cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Predecessor will write down the carrying amount of the oil and natural gas properties to fair value. The factors used to determine fair value include, but are not limited to, estimates of reserves, future commodity prices, future production estimates, estimated future capital expenditures and a commensurate discount rate. Unproved

Note 4—Property and Equipment (Continued)

properties are assessed at least annually to determine whether they have been impaired and more frequently when industry conditions dictate an impairment may be possible. An impairment allowance is provided on an unproved property when the Predecessor determines that the property will not be developed.

For the nine months ended September 30, 2016, the Predecessor recorded an impairment of $0.3 million due to unproved property leases that expired during the period and incurred dry hole costs of $1.1 million related to a vertical test well drilled to an unproductive shallow horizon. The Predecessor did not record impairments of proved properties for the nine months ended September 30, 2016 and September 30, 2015.

Impairment and dry hole costs are presented in the unaudited condensed consolidated statements of operations within "Impairment of oil and natural gas properties and dry hole cost."

Note 5—Asset Retirement Obligations

The following table summarizes the changes in asset retirement obligations for the nine months ended September 30, 2016 (in thousands):

Balance, December 31, 2015	$ 608
Liabilities incurred and assumed	62
Liabilities settled upon plugging and abandoning wells	(113)
Revisions to estimated cash flows(1)	(213)
Liabilities eliminated through asset sale	(6)
Accretion	42
Balance, September 30, 2016	380
Less current portion of obligations	—
Noncurrent asset retirement obligations	$ 380

(1) Revisions in estimated cash flows during the nine months ended September 30, 2016 are primarily attributable to decreased estimates of future costs for oil field goods and services required to plug and abandon wells.

Any asset retirement obligation classified as current is included in accrued liabilities on the condensed consolidated balance sheet. At September 30, 2016, all asset retirement obligations were classified as noncurrent.

Note 6—Commodity Derivative Instruments

The Predecessor hedges a portion of its crude oil sales using fixed price swap agreements based on futures price contracts for WTI crude oil. The Predecessor has not designated its commodity derivative contracts as hedging instruments for financial reporting purposes. Accordingly, commodity derivative

Note 6—Commodity Derivative Instruments (Continued)

contracts are marked to market each quarter, with the change in fair value during the reporting period recognized currently as a gain or loss in "Gain (loss) on commodity derivatives" in the unaudited condensed consolidated statements of operations. The Predecessor estimates the fair value using risk adjusted discounted cash flow calculations. Cash flows are based on published futures commodity price curves for the underlying commodity as of the date of the estimate. Due to the volatility of commodity prices, the estimated fair values of the Predecessor's derivative instruments are subject to fluctuation from period to period, which could result in significant differences between the current estimated fair value and the ultimate settlement price.

At December 31, 2015, the Predecessor was not party to any commodity derivatives for future periods.

The following table summarizes the approximate volumes and average contract prices of swap contracts in place as of September 30, 2016 expiring during the periods indicated:

	Three Months Ended December 31, 2016	Year Ended December 31, 2017	Year Ended December 31, 2018
Notional volume (Bbl)	293,575	870,000	475,700
Weighted average floor price ($/Bbl)(1)	$ 45.39	$ 45.81	$ 50.66

(1) Derivative prices are based on NYMEX oil prices. The prices we receive are affected by quality, energy content, location, and transportation differentials.

The Predecessor has agreements in place with all counterparties that allow for the financial right of offset for derivative assets and derivative liabilities at settlement or in the event of a default under the agreements. Although these agreements are in place, the derivative assets and liabilities in the Predecessor's condensed consolidated balance sheets are shown without effect of counterparty netting arrangements.

Gains and losses on derivatives are reported in the consolidated statements of operations. The following table presents the Predecessor's gains and losses on derivative instruments (in thousands):

	Nine Months Ended September 30, 2016
Beginning fair value of commodity derivatives	$ —
(Loss) gain on commodity derivatives(1)	(8,208)
Commodity derivative cash settlements paid (received)	1,159
Ending fair value of commodity derivatives	$(7,049)

(1) Realized and unrealized (Loss) gain on commodity derivatives is recorded in the Other Income (Expense) section of the Condensed Consolidated Statements of Operations.

Note 6—Commodity Derivative Instruments (Continued)

The Predecessor's counterparty credit exposure related to commodity derivative instruments is represented by the fair value of contracts with a net positive fair value at the reporting date. These outstanding instruments expose the Predecessor to credit risk in the event of nonperformance by the counterparties to the agreements. Should the creditworthiness of the Predecessor's counterparties decline, its ability to mitigate nonperformance risk is limited to a counterparty agreeing to either a voluntary termination and subsequent cash settlement or a novation of the derivative contract to a third party.

Note 7—Fair Value Measurements

The Predecessor has categorized its assets and liabilities measured at fair value, based on the priority of inputs to the valuation technique, into a three-level fair value hierarchy. The fair value hierarchy gives the highest priority to quoted prices in active markets or identical assets of liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3).

Assets and liabilities recorded at fair value on the consolidated balance sheets are categorized based on the inputs to the valuation techniques as follows:

Level 1—Assets and liabilities recorded at fair value for which unadjusted quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. Level 1 primarily consists of financial instruments such as exchange-traded derivatives, listed securities and U.S. government treasury securities.

Level 2—Assets and liabilities recorded at fair value for which pricing inputs are other than quoted prices in active markets included in Level 1, which are either directly or indirectly observable as of the reporting date. Level 2 includes those financial instruments that are valued using models or other valuation methodologies. These models are primarily industry standard models that consider various assumptions, including quoted prices for commodities, time value, volatility factors and current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace. Instruments in the category include nonexchange-traded derivatives such as over-the-counter forwards, swaps and options.

Level 3—Assets and liabilities recorded at fair value using include pricing inputs that are generally less observable from objective sources. These inputs may be used with internally developed methodologies that result in management's best estimate of fair value, and the Predecessor does not have sufficient corroborating market evidence to support classifying these assets and liabilities as Level 2.

Note 7—Fair Value Measurements (Continued)

Fair Value Measurement on a Recurring Basis

The following table is a listing of the Predecessor's assets and liabilities that are measured at fair value on a recurring basis and where they were classified within the fair value hierarchy as of September 30, 2016 (in thousands):

As of September 30, 2016	Level 1	Level 2	Level 3	Total
Assets:				
Commodity derivative instruments	$—	$ 240	$—	$ 240
Liabilities:				
Commodity derivative instruments	$—	$7,289	$—	$7,289

The assets and liabilities are categorized within the above fair value hierarchy based on the lowest level of input that is significant to the fair value measurement. There were no transfers between Level 1, Level 2 or Level 3 during any period presented. The Predecessor had no financial assets or liabilities measured at fair value on a recurring basis as of December 31, 2015.

Fair Value of Other Financial Instruments

The book values of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities approximate fair value due to the short-term nature of these instruments. The book value of the Predecessor's credit facility approximates fair value as the variable interest rates are reflective of current market conditions.

Assets and Liabilities Measured on a Nonrecurring Basis

Acquired assets and liabilities are recorded at fair value as of the acquisition date. The valuation techniques that may be used to fair value acquisitions include either the income approach or the market approach. The Predecessor reviews its proved oil and natural gas properties for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying amount of such property. In such circumstances, the income approach is used to determine the fair value of proved oil and natural gas reserves. The income approach uses a discounted cash flow model based on market assumptions as to future commodity prices, projections of estimated quantities of oil and natural gas reserves, expectations for timing and amount of future development and operating costs, projections of future rates of production, expected recovery rates and risk adjusted discount rates. Given the unobservable nature of the inputs, nonrecurring measurements of business combinations using the income approach are deemed to be classified within Level 3 inputs. The market approach uses prices and other relevant information generated by market transactions involving identical or comparable asserts or liabilities.

Unproved oil and natural gas property costs are evaluated for impairment and reduced to fair value when there is an indication that the carrying costs may not be recoverable. To measure the fair

Note 7—Fair Value Measurements (Continued)

value of the unproved properties, the Predecessor uses a market approach, which takes into account future development plans, remaining lease term, drilling results, and reservoir performance.

Additionally, the Predecessor uses fair value to determine the inception value of its asset retirement obligations. The inputs used to determine such fair value are based primarily on the present value of estimated future cash inflows and outflows. Given the unobservable nature of these inputs, they are generally classified within Level 3.

Note 8—Debt Obligations

On June 19, 2015, the Predecessor entered into a credit agreement which provided for a $500.0 million five-year senior secured revolving credit facility that matures on June 19, 2020 (credit facility).

At December 31, 2015, the Predecessor had a $35.0 million borrowing base with $20.0 million outstanding and $15.0 million available on the credit facility.

The credit facility has two scheduled borrowing base redeterminations per year. The Predecessor has the option to request up to two additional quarterly redeterminations per year. Future borrowing bases will be computed based on proved oil and natural gas reserves, hedge positions and estimated future cash flows from those reserves (as governed in the credit agreement), as well as any other outstanding debt.

The credit facility is secured by oil and natural gas properties representing at least 80% of the value of the Predecessor's proved reserves. The credit facility contains certain covenants, including among others, restrictions on indebtedness, restrictions on liens, restrictions on investments, restrictions on mergers, restrictions on sales of assets, restrictions on dividends and payments to the Predecessor's capital interest holders, restrictions on the level of cash balances and restrictions on the Predecessor's hedging activity. The financial covenants require the Predecessor to maintain a current ratio (as defined) of at least 1.0 to 1.0 and a leverage ratio (as defined) not greater than 4.0 to 1.0. The Predecessor was in compliance with the financial covenants as of September 30, 2016.

On April 26, 2016, the Predecessor entered into an amendment of its credit facility that increased the borrowing base from $35.0 million to $65.0 million and increased the number of lenders from one bank to five banks. Additionally, as a result of the amendment, the prime rate and federal funds rate, which vary based on the utilization percentage of the credit facility, were adjusted to 1.5% to 2.5% for base rate loans and 2.5% to 3.5% for LIBOR loans. The commitment fee rate was set to 0.5% for all utilization levels of the credit facility.

On June 29, 2016, the Predecessor entered into an amendment that increased the borrowing base on the credit facility to $100.0 million.

On September 30, 2016, the Predecessor entered into an amendment that increased the credit facility borrowing base from $100.0 million to $160.0 million. As of September 30, 2016, the

Note 8—Debt Obligations (Continued)

outstanding borrowings under the credit facility were $90.0 million resulting in $70.0 million in borrowing capacity under the credit facility.

The Predecessor capitalized $0.09 million and $0.01 million of interest during the nine months ended September 30, 2016 and September 30, 2015, respectively.

Note 9—Members' Equity

Capital Interests

The Predecessor is a limited liability company with capital interests owned by Quantum and certain officers of the Predecessor. The total capital commitment from all Jagged Peak Energy LLC capital members is $405.9 million, with Quantum representing 98.55% of the total capital commitment. Capital interests in the Predecessor consist of a single class of units, which receive an internal rate of return threshold of 8% prior to distributions to any other class of equity interests.

Management Incentive Units

The Predecessor has established an Incentive Pool Plan, whereby the Predecessor may grant Management Incentive Units ("MIUs") to employees or selected other participants. The MIUs are considered "profits interests" that participate in certain events whereupon distributions are made to MIU holders (only after certain return thresholds are achieved by the capital interests) following a qualifying initial public offering, sale, merger, or other qualifying transaction involving the stock or assets of the Predecessor ("Vesting Event"). The MIUs have no voting rights and partially vest over four years with the remainder vesting upon a Vesting Event. Prior to a Vesting Event, vested units will be forfeited if an incentive unit holder's employment is terminated for cause or if the unit holder terminates his or her employment. Compensation expense for the MIUs will be recognized when all performance, market and service conditions are probable of being satisfied, which is generally upon a Vesting Event.

On March 25, 2016, the Predecessor and certain MIU holders employed by the Predecessor on April 1, 2016 ("MIU advance recipients") entered into the First Amendment to the Limited Liability Company Agreement (the "Distribution Agreement") under which the Predecessor made a $14.7 million cash advance to MIU advance recipients during April 2016. Under the terms of the Distribution Agreement, the distribution will be treated as an advance and will dollar for dollar offset distributions otherwise payable to MIU advance recipients. If a MIU advance recipient's business relationship with the Predecessor is terminated prior to the MIU advance being fully offset by subsequent distributions, the MIU advance recipient will have to return the MIU advance less reasonable taxes paid. The MIU advance is deferred as a long-term asset within other assets, and will be reviewed for recoverability at each reporting period or when changes in circumstances indicate the asset may no longer be recoverable, such as when a MIU advance recipient terminates employment with the Predecessor. Compensation expense will be recognized if the MIU advance asset is no longer recoverable or upon the occurrence of a Vesting Event.

Note 9—Members' Equity (Continued)

As of September 30, 2016 and December 31, 2015, 2,392,813 and 2,350,000 MIUs, respectively, were outstanding from the total pool of 2,600,000 authorized MIUs.

Contributions and Distributions

Capital calls approved by the board of directors are funded on a pro rata basis by all of the capital members. During the nine months ended September 30, 2016 and September 30, 2015, the Predecessor received $31.5 million and $38.0 million, respectively, of capital contributions from its capital members to fund acquisitions, operations and the MIU advance. As of September 30, 2016, the capital members of the Predecessor had remaining capital commitments of approximately $79.8 million.

Note 10—Related Party Transactions

Quantum owns significant capital interests in the Predecessor, a 41.5% interest in Oryx Midstream Services, LLC (together with Oryx Southern Delaware Holdings, LLC, Oryx), a 61% interest in Phoenix Lease Services, LLC (Phoenix) and an indirect interest in Trident Water Services, LLC (Trident), a wholly owned subsidiary of Phoenix.

During the nine months ended September 30, 2016, the Predecessor paid aggregate fees of $0.6 million, $0.3 million and $2.1 million to Trident, Phoenix and Oryx, respectively. During the nine months ended September 30, 2015, the Predecessor paid aggregate fees of $0.4 million, $0.3 million and $0.4 million to Trident, Phoenix and Oryx, respectively.

Trident provides water transfer services to the Predecessor and Phoenix rents certain equipment to the Predecessor. The Predecessor is under no obligation to use either provider, and both provide services only when selected as a vendor in the Predecessor's normal bidding process. Oryx provides the Predecessor crude oil gathering services and sells related equipment and maintenance services to the Predecessor. The crude oil gathering services provided by Oryx are pursuant to a 12-year crude oil gathering agreement.

Note 11—Commitments and Contingencies

Contractual Obligations

As of September 30, 2016, the Predecessor had drilling commitments on three rigs. In the event of early termination, the Predecessor would be obligated to pay up to $3.6 million as of September 30, 2016, as required under the terms of the contracts. In May 2016, the Predecessor provided notice to terminate one of its drilling rigs and incurred an early termination charge of approximately $0.2 million. This amount was recorded in the condensed consolidated statements of operations within the other operating expenses line item.

There have been no other material changes in its contractual commitments and obligations from amounts listed under "Note 10—Commitments and Contingencies" in the Predecessor's consolidated financial statements for the year ended December 31, 2015.

Note 12—Income Taxes

The Predecessor is treated as a partnership for federal and state income tax purposes, with each partner taxed separately on its allocated share of the Predecessor's taxable income. Accordingly, the accompanying consolidated financial statements do not include a provision or liability for federal income taxes. The Predecessor's operations in Texas are subject to an entity-level tax, the Texas franchise tax, at a statutory rate of up to 1.0% of a portion of gross revenues apportioned to Texas. The Predecessor did not have taxable net income for purposes of calculating Texas franchise tax for the nine months ended September 30, 2016 and September 30, 2015. As of September 30, 2016 and December 31, 2015, the Predecessor did not have a franchise tax liability.

ANNEX A

GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of certain terms used in this document, which are commonly used in the oil and natural gas industry:

3-D seismic. Geophysical data that depict the subsurface strata in three dimensions. 3-D seismic typically provides a more detailed and accurate interpretation of the subsurface strata than 2-D, or two-dimensional, seismic.

Analogous reservoir. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an analogous reservoir refers to a reservoir that shares the following characteristics with the reservoir of interest: (i) same geological formation (but not necessarily in pressure communication with the reservoir of interest); (ii) same environment of deposition; (iii) similar geological structure; and (iv) same drive mechanism. For a complete definition of analogous reservoir, refer to the SEC's Regulation S-X, Rule 4-10(a)(2).

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.

Bcf. One billion cubic feet of natural gas.

Boe. One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil. This is an energy content correlation and does not reflect a value or price relationship between the commodities.

Boe/d. One Boe per day.

British thermal unit or *Btu*. The quantity of heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

Completion. Preparation of a well bore and installation of permanent equipment for production of oil, natural gas or NGLs or, in the case of a dry well, reporting to the appropriate authority that the well has been abandoned.

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.

Delineation. The process of placing a number of wells in various parts of a reservoir to determine its boundaries and production characteristics.

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

Development costs. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and natural gas. For a complete definition of development costs, refer to the SEC's Regulation S-X, Rule 4-10(a)(7).

Development project. The means by which petroleum resources are brought to the status of economically producible. As examples, the development of a single reservoir or field, an incremental development in a producing field or the integrated development of a group of several fields and associated facilities with a common ownership may constitute a development project.

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

Differential. An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.

Dry well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

Economically producible. The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. For a complete definition of economically producible, refer to the SEC's Regulation S-X, Rule 4-10(a)(10).

Estimated ultimate recovery or *EUR*. The sum of reserves remaining as of a given date and cumulative production as of that date.

Exploration costs. Costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects of containing oil and natural gas reserves, including costs of drilling exploratory wells and exploratory-type stratigraphic test wells. For a complete definition of exploration costs, refer to the SEC's Regulation S-X, Rule 4-10(a)(12).

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 or natural gas in another reservoir.

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. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations. For a complete definition of field, refer to the SEC's Regulation S-X, Rule 4-10(a)(15).

Formation. A layer of rock which has distinct characteristics that differs from nearby rock.

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

Held by production. Acreage covered by a mineral lease that perpetuates a company's right to operate a property as long as the property produces a minimum paying quantity of oil or natural gas.

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.

MBbl. One thousand barrels of crude oil, condensate or NGLs.

MBoe. One thousand Boe.

Mcf. One thousand cubic feet of natural gas.

Mcf/d. One Mcf per day.

MMBbl. One million barrels of crude oil, condensate or NGLs.

MMBoe. One million Boe.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

Net acres. The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

Net production. Production that is owned by us less royalties and production due to others.

Net revenue interest. A working interest owner's gross working interest in production less the royalty, overriding royalty, production payment and net profits interests.

NGLs. Natural gas liquids. Hydrocarbons found in natural gas which may be extracted as liquefied petroleum gas and natural gasoline.

NYMEX. The New York Mercantile Exchange.

Offset operator. Any entity that has an active lease on an adjoining property for oil, natural gas or NGLs purposes.

Operator. The individual or company responsible for the development and/or production of an oil or natural gas well or lease.

Play. A geographic area with hydrocarbon potential.

Production costs. Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. For a complete definition of production costs, refer to the SEC's Regulation S-X, Rule 4-10(a)(20).

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.

Proration unit. A unit that can be effectively and efficiently drained by one well, as allocated by a governmental agency having regulatory jurisdiction.

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 deemed to have potential for the discovery of commercial hydrocarbons.

Proved area. The part of a property to which proved reserves have been specifically attributed.

Proved developed reserves. Reserves that can be expected to be recovered through (i) existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared with the cost of a new well or (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.

Proved properties. Properties with proved reserves.

Proved reserves. Those quantities of oil, natural gas and NGLs, 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—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. For a complete definition of proved oil and natural gas reserves, refer to the SEC's Regulation S-X, Rule 4-10(a)(22).

Proved undeveloped reserves or *PUDs*. 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.

Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances justify a longer time.

Under no circumstances shall estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

Realized price. The cash market price less all expected quality, transportation and demand adjustments.

Reasonable certainty. A high degree of confidence that quantities will be recovered. For a complete definition of reasonable certainty, refer to the SEC's Regulation S-X, Rule 4-10(a)(24).

Recompletion. The completion for production of an existing wellbore in another formation from that which the well has been previously completed

Reliable technology. 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.

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. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered 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.

Resources. Quantities of oil and natural gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

Royalty. An interest in an oil and natural gas lease that gives the owner the right to receive a portion of the production from the leased acreage (or of the proceeds from the sale thereof), but does not require the owner to pay any portion of the production or development costs on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

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.

Spot market price. The cash market price without reduction for expected quality, transportation and demand adjustments.

Spud. Commenced drilling operations on an identified location.

Stacked hydrocarbon-bearing formations. Vertically layered geologic zones that exist at differing underground depths and are capable of producing oil, natural gas and NGLs. The existence of stacked-hydrocarbon bearing formations enables the development of multiple hydrocarbon bearing zones from a common surface area.

Standardized measure. Discounted future net cash flows estimated by applying year-end prices to the estimated future production of year-end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end costs to determine pre-tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the oil and natural gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

Stratigraphic test well. A drilling effort, geologically directed, to obtain information pertaining to a specific geologic condition. Such wells customarily are drilled without the intent of being completed for hydrocarbon production. The classification also includes tests identified as core tests and all types of expendable holes related to hydrocarbon exploration. Stratigraphic tests are classified as "exploratory type" if not drilled in a known area or "development type" if drilled in a known area.

Success rate. The percentage of wells drilled which produce hydrocarbons in commercial quantities.

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.

Unit, drilling unit or *spacing unit*. The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

Unproved properties. Properties with no proved reserves.

Wellbore. The hole drilled by the bit that is equipped for oil, natural gas and NGL production on a completed well. Also called well or borehole.

Working interest. The right granted to the lessee of a property to develop and produce and own natural gas or other minerals. The working interest owners bear the exploration, development and operating costs on either a cash, penalty or carried basis.

Workover. Operations on a producing well to restore or increase production.

WTI. West Texas Intermediate.

Until , 2017 (25 days after commencement of this offering), all dealers that effect transactions in our common stock, whether or not participating in this offering, may be required to deliver a prospectus. This is in addition to the dealer's obligation to deliver a prospectus when acting as an underwriter and with respect to unsold allotments or subscriptions.