ROSEHILL RESOURCES

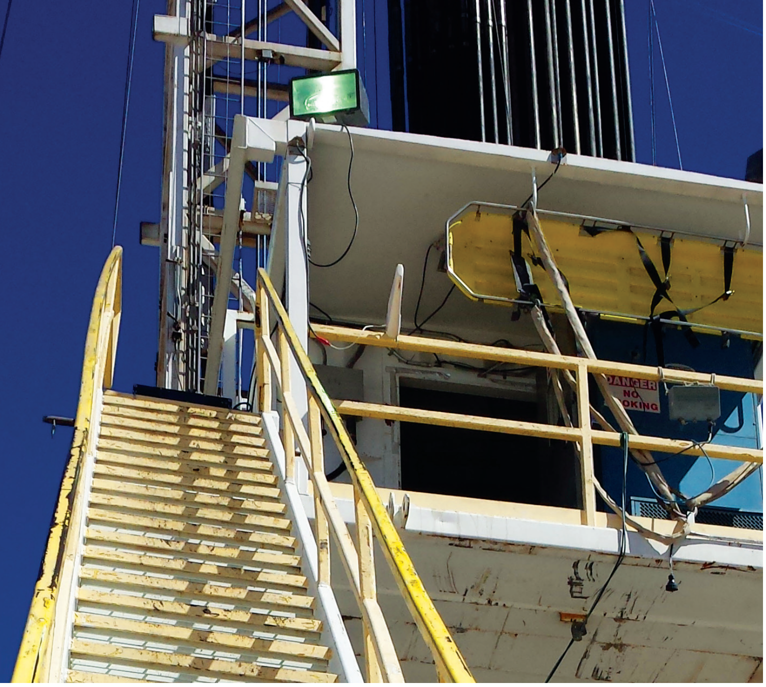
2017 Annual Report

Driving Shareholder Value

Well done is better than well said and we’ve got the results to prove it.

Rosehill Resources is an independent oil and natural gas company focused on optimizing operations, maintaining financial discipline and expanding its Delaware Basin footprint. With more than 11,000 net acres and over 470 drilling locations across multiple stacked horizons, Rosehill’s strategy for its premier Delaware Basin portfolio is to build a solid foundation of highly economic production and reserves growth through operational excellence and acquisitions.

In 2017, Rosehill more than doubled its acreage position and reserves while significantly ramping up its development drilling and production. With drilling on the new White Wolf acquisition acreage to begin in 2018 and continued strong oil prices, Rosehill will be getting to a size and scale that adds operational and financial efficiencies that should add significant value to its shareholders.



"Our talented management, technical and financial teams have worked diligently to add significant value."

A LETTER FROM J. A. (ALAN) TOWNSEND

Dear Shareholders,

2017 was a remarkable and exciting year for Rosehill Resources. Since the transaction forming Rosehill Resources as a publicly traded company on April 27, 2017, our talented management, technical and financial teams have worked diligently to add significant value. We have had notable operational accomplishments in drilling, completion and production growth, completed the divestiture of our Barnett Shale assets and finalized the White Wolf acquisition in December. We are a pure play Delaware Basin company with over 11,000 net acres having more than 470 identified drilling locations with a rapidly growing production stream.

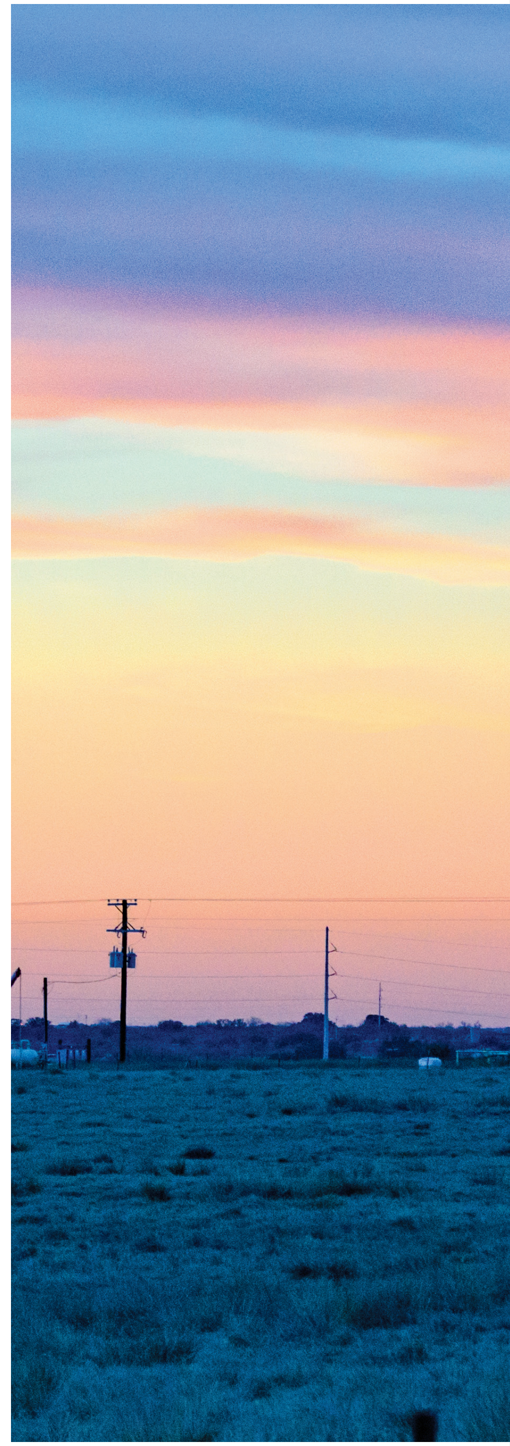
Our growth began prior to the closing of the transaction with the deployment of two rigs on our Loving County acreage and the subsequent ramp up of production as we drilled, completed, and turned these new wells to sales. Our production grew in 2017 and continues to grow significantly in 2018. Starting with a base production level of just over 5,000 barrels of oil equivalent per day “BOEPD” in late April of 2017, we more than doubled our production to over 10,000 BOEPD by late December of 2017. We recently surpassed 15,000 BOEPD in March of 2018 and

"Rosehill's strategy for its premier Delaware Basin portfolio is to build a solid foundation of highly economic production and reserves growth through operational excellence and acquisitions."

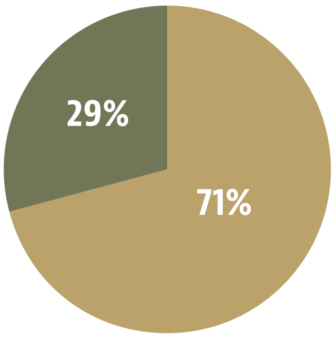
expect meaningful growth in the future. From year-end 2016 to the end of 2017, we increased our proved reserves by 135% to 31.1 MMBOE and our PV-10 valuation of proved reserves more than tripled to $368 million.

We believe there is tremendous potential in our Delaware Basin assets which are located in the premier U.S. onshore shale basin. There is immense upside throughout the basin across 10 productive stacked pay benches. We see superior reservoir quality, with high oil cuts, several overpressured benches, good porosity and thickness and natural fractures are abundant increasing drainage efficiency. We are seeing strong EURs in the benches we are currently drilling in with the potential for downspacing. The Delaware Basin has some of the lowest breakeven costs and highest rates of return anywhere in the world. We are confident that we have the right team in place to execute on our strategy and to deliver value to our shareholders.

During the year, our technical and operations teams were focused on optimizing capital deployment. Our drilling group continues to demonstrate meaningful improvements in drilling efficiency that have reduced average spud to total depth drilling times in Loving County from nearly 30 days a year ago to under 15 days on average across all zones. Our operational and geological teams are contin-



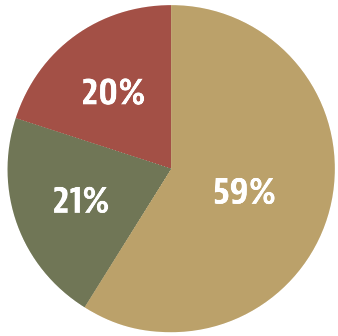
"We believe there is tremendous potential in our assets which are all located in the Delaware Basin, the premier U.S. onshore shale basin."



Total 3P Reserves by Category
(percent)

No reserves booked at 12/31/17 associated with White Wolf acquisition. Significant opportunity for future reserves growth associated with the acquisition.

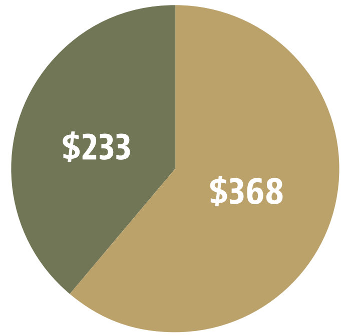
Proved Unproved



Proved Reserves by Commodity
(percent)

High liquids-weighted reserves drive value creation.

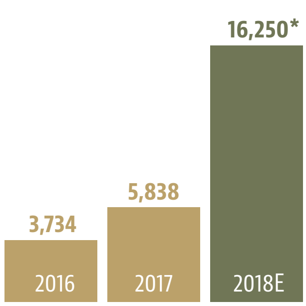
Oil Gas NGLs



Total 3P PV-10 by Category
($ in millions)

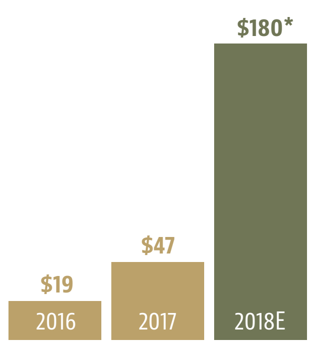
Substantial upside to PV-10 value with current strip pricing vs. 2017 SEC pricing.

Proved Unproved



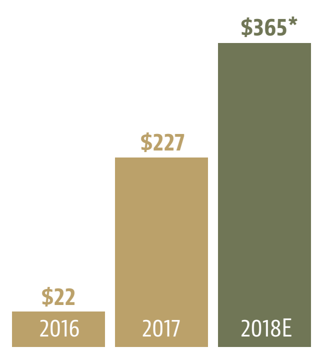
Average Daily Production
(BOEPD)

Production forecasted to nearly triple from 2017 to 2018.



Adjusted EBITDAX
($ in millions)

Adjusted EBITDAX forecasted to nearly quadruple from 2017 to 2018.



Capital Spending
($ in millions)

Ramping up capital spend to achieve profitable growth in production and Adjusted EBITDAX.

** Midpoint of 2018 guidance range, as of December 2017.*

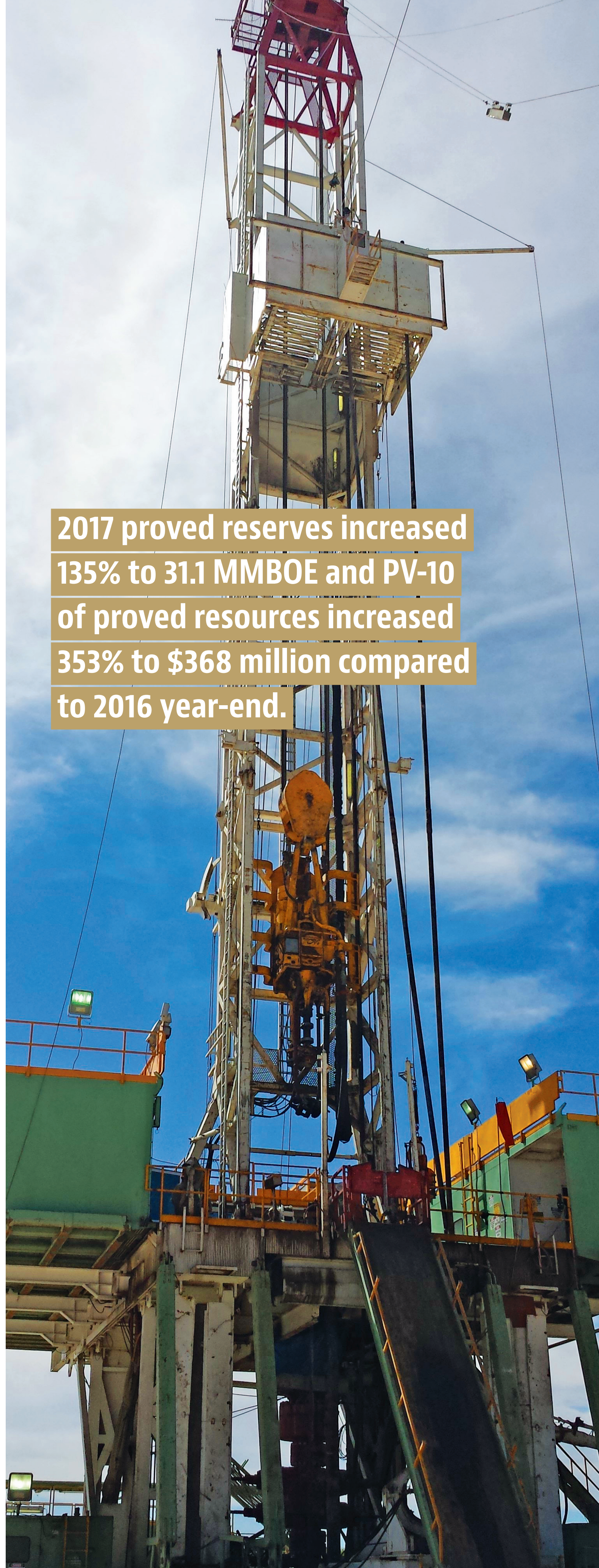
uously testing and improving our completion and frac designs, mapping fracture stimulation jobs to determine optimum well spacing, de-risking additional horizontal horizons, and building out additional infrastructure.

Rosehill's aggressive drilling program was designed to both ramp up cash flow late in 2017, and to grow a stronger, more sustainable public company in 2018. With two rigs deployed on our 4,500 legacy acres, we may have had the highest rig to acre ratio in the basin, and it was our strategy to add acreage through acquisitions to increase our future well inventory. This was accomplished with the White Wolf acquisition in December that more than doubled Rosehill's acreage position and well inventory. In the 2nd quarter of 2018, we will begin the delineation and development of the White Wolf acreage in northern Pecos County. We will continue to pursue strategic acquisition opportunities in 2018 and beyond that will be accretive to our shareholders.

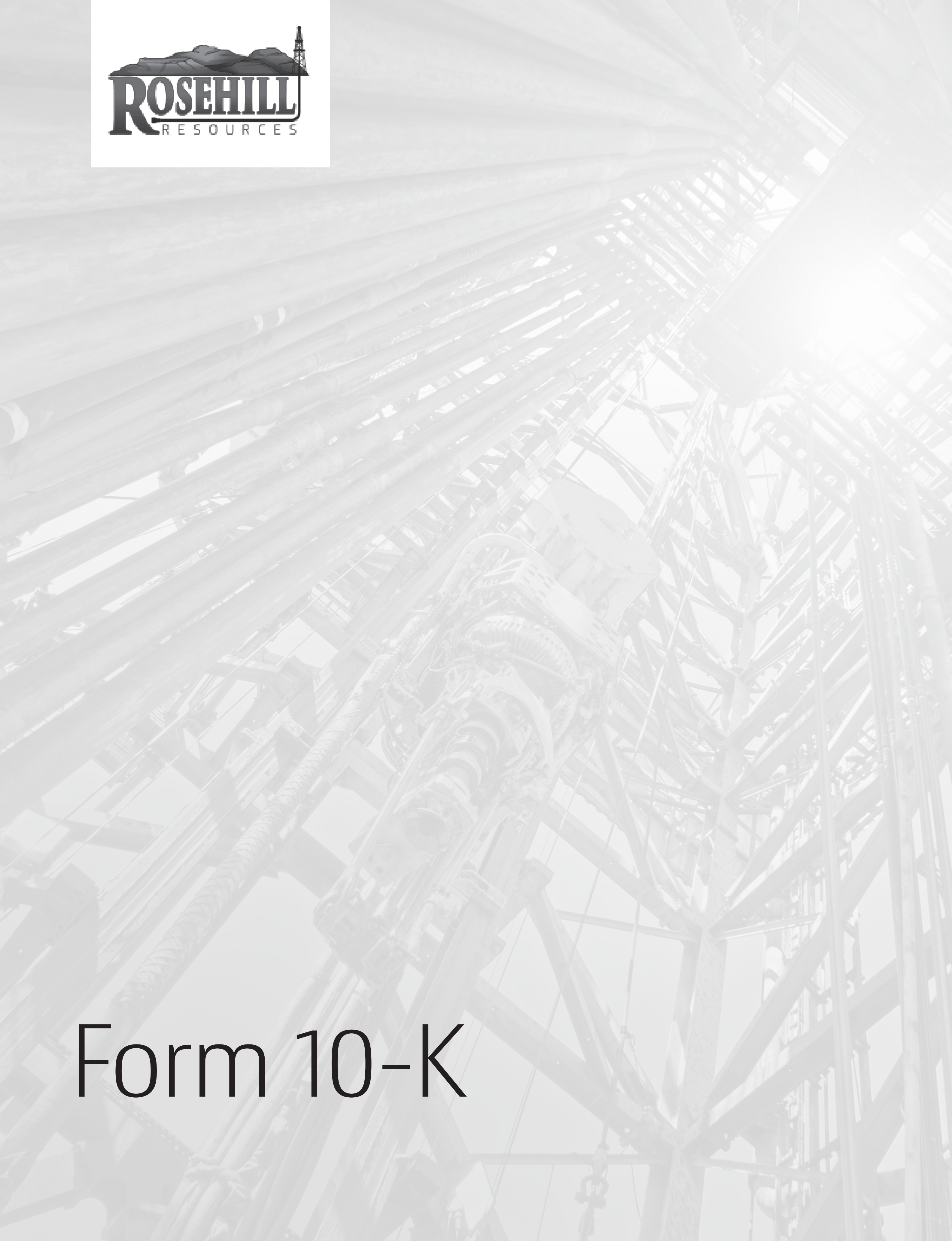
On the financial front, we have upgraded our accounting and financial reporting staff, financed the White Wolf acquisition, and continuously examine ways to address our capital structure and potential future financing needs. In March of 2018, we entered into a new, syndicated credit facility that doubled our borrowing base to $150 million giving us additional liquidity to continue to execute on our capital program and expand our production and reserve growth.

As our results have shown, we are focused on improving everything that we do operationally. We are confident in our operational capabilities, which will help us to maximize value and generate sustainable growth. With our strong production results in Loving County, White Wolf development activities ramping up, and sustained higher oil pricing, we are growing our Company and expect significant increases in Adjusted EBITDAX. We are a pure-play Delaware Basin company, with a growth ramp in production, Adjusted EBITDAX and per share value that positions us at the top of our very strong peer group. We have captured a prolific acreage position in one of the best basins in the world and we intend to further expand and fortify our position through accretive acquisitions. We have a clear vision with an experienced operational and management team poised to create considerable value for our shareholders.

J. A. (ALAN) TOWNSEND
President and Chief Executive Officer



ROSEHILL RESOURCES



Form 10-K

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

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

FOR THE FISCAL YEAR ENDED DECEMBER 31, 2017

OR

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

FOR THE TRANSITION PERIOD FROM ___________ TO ___________

Commission File Number 001-37712

ROSEHILL RESOURCES Inc.

(Exact name of registrant as specified in its charter)

Delaware	**47-5500436**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

16200 Park Row, Suite 300
Houston, TX 77084
(Address of principal executive offices)
(281) 675-3400
(Registrant's telephone number, including area code)

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

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

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or Section 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the Registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark whether the Registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ☒ No ☐

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

Indicate by check mark whether the Registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, smaller reporting company, or an emerging growth company. See the definitions of large accelerated filer, accelerated filer, smaller reporting company, and emerging growth company in Rule 12b-2 of the Exchange Act.

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

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

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

The aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2017, the last business day of the registrant's most recently completed second fiscal quarter, was approximately $26.2 million based on the last sales price of the shares as reported on the NASDAQ market on that date.

As of March 29, 2018, there were 6,222,299 shares of Class A common stock, par value $0.0001 per share, and 29,807,692 shares of Class B common stock, par value $0.0001 per share, outstanding.

ROSEHILL RESOURCES INC.
FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2017

TABLE OF CONTENTS

GLOSSARY OF TERMS

The following are abbreviations and definitions of certain terms commonly used in the oil and natural gas industry and in this Annual Report on Form 10-K.

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.

Acquisition of properties. Costs incurred to purchase, lease or otherwise acquire a property, including costs of lease bonuses and options to purchase or lease properties, the portion of costs applicable to minerals when land including mineral rights is purchased in fee, brokers' fees, recording fees, legal costs, and other costs incurred in acquiring properties.

Analogous reservoirs. Analogous reservoirs, as used in resource 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, analogous reservoir refers to a reservoir that shares all of the following characteristics with the reservoir of interest: (i) the same geological formation (but not necessarily in pressure communication with the reservoir of interest); (ii) the same environment of deposition; (iii) similar geologic structure; and (iv) same drive mechanism.

Basin. A large depression on the earth's surface in which sediments accumulate.

Bbl. One stock tank barrel or 42 U.S. gallons liquid volume used in reference to crude oil or other liquid hydrocarbons.

Bbls/d. Barrels per day.

Bcf. Billion cubic feet.

Boe. One barrel of oil equivalent determined using a ratio of six thousand cubic feet (Mcf) of natural gas being equivalent to one Bbl of crude oil, condensate or natural gas liquids.

Boe/d. Barrels of oil equivalent per day.

Btu. British thermal unit, which is the heat required to raise the temperature of a one-pound mass of water from 58.5 to 59.5 degrees Fahrenheit.

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

Condensate. Condensate is 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. For additional information, see the SEC's definition in Rule 4-10(a)(4) of Regulation S-X, a link for which is available at the SEC's website.

Crude oil. Liquid hydrocarbons retrieved from geological structures underground to be refined into fuel sources.

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 gas.

Development project. A development project is 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 hole or well. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would 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.

Exploitation. A development or other project which may target proven or unproven reserves (such as probable or possible reserves), but which generally has a lower risk than that associated with exploration projects.

Exploratory well. A well drilled to find and produce natural gas or oil reserves not classified as proved, to find a new reservoir in a field previously found to be productive of natural gas or oil in another reservoir or to extend a known reservoir.

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

Formation. A layer of rock that has distinct characteristics that differs from nearby rock.

Fracturing. The process of creating and preserving a fracture or system of fractures in a reservoir rock typically by injecting a fluid under pressure through a wellbore and into the targeted formation.

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

Henry Hub. A distribution hub of natural gas pipelines used as a benchmark in natural gas pricing and the underlying commodity of NYMEX natural gas futures contracts.

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 with a specified interval.

Horizontal wells. Wells drilled directionally horizontal to allow for development of structures not reachable through traditional vertical drilling mechanisms.

Hydrocarbons. Oil, NGLs and natural gas are all collectively considered hydrocarbons.

Liquids. Oil and NGLs.

MBbls. One thousand barrels of crude oil or other liquid hydrocarbons.

MBoe. One thousand barrels of crude oil equivalent, using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Mcf. One thousand cubic feet.

Mcf/d. One thousand cubic feet of natural gas per day.

Mineral interests. The interests in ownership of the resource and mineral rights, giving an owner the right to profit from the extracted resources.

MGal. One thousand gallons of natural gas liquids or other liquid hydrocarbons.

MMBbls. One million barrels of crude oil or other liquid hydrocarbons.

MMBoe. One million barrels of crude oil equivalent, using a ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or NGLs.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

Net acres. The sum of the fractional working interest owned in gross acres.

Net production. Production that is owned by the Company less royalties and production due others.

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

Net wells. The sum of the fractional working interest owned in gross wells.

NGLs. The combination of ethane, propane, butane, pentane and isobutane that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

NYMEX. New York Mercantile Exchange.

Oil. Crude oil and condensate.

Oil and natural gas properties. Tracts of land consisting of properties to be developed for oil and natural gas resource extraction.

Operating interest. An interest in natural gas and oil that is burdened with the cost of development and operation of the property.

Operator. The individual or company responsible for the exploration and/or production of an oil or natural gas well or lease.

Play. A set of discovered or prospective oil and/or natural gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, reservoir structure, timing, trapping mechanism and hydrocarbon type.

Plugging and abandonment. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of all states require plugging of abandoned wells.

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

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 to the cost of a new well; and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Proved developed non-producing. Proved oil and natural gas reserves that are developed behind pipe or shut-in or that can be recovered through improved recovery only after the necessary equipment has been installed, or when the costs to do so are relatively minor. Shut-in reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not started producing, (2) wells that were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe reserves are expected to be recovered from zones in existing wells that will require additional completion work or future recompletion prior to the start of production.

Proved reserves. Proved oil and natural gas reserves are those quantities of oil and gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—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.

Proved undeveloped reserves ("PUD"). Proved undeveloped oil and gas 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.

(i) Proved 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.

(ii) Proved 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.

(iii) 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.

PV-10. When used with respect to natural gas , oil and NGL reserves, PV-10 means the present value of the estimated future net revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs in effect as of the date of the report or estimate, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%. Also referred to as "present value." After-tax PV-10 is also referred to as "standardized measure" and is net of future income tax expense.

Realized price. The cash market price less all expected quality, transportation and demand adjustments.

Recompletion. The completion for production of an existing wellbore in another formation from that which the well has been previously completed.

Reserves. Reserves are 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 the 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 reserves.

Royalty interest. An interest that gives an owner the right to receive a portion of the resources or revenues without having to carry any costs of development or operations.

SEC. United States Securities and Exchange Commission.

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

Standardized measure. The present value of estimated future net revenues to be generated from the production of proved reserves, determined in accordance with assumptions required by the Financial Accounting Standards Board and the Securities and Exchange Commission (using current costs and the average annual prices based on the unweighted arithmetic average of the first-day-of-the-month price for each month) without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expenses or to depreciation, depletion and amortization, and discounted using an annual discount rate of 10%. Federal income taxes have not been deducted from future production revenues in the calculation of standardized measure as each partner is separately taxed on its share of Legacy's taxable income. In addition, Texas margin taxes and the federal income taxes associated with a corporate subsidiary have not been deducted from future production revenues in the calculation of the standardized measure as the impact of these taxes would not have a significant effect on the calculated standardized measure. Standardized measure does not give effect to commodity derivative transactions.

Tight formation. A formation with low permeability that produces natural gas with very low flow rates for long periods of time.

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.

Undeveloped oil, natural gas and NGL reserves. Undeveloped oil, natural gas and NGL reserves are reserves of any category 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. Also referred to as "undeveloped reserves."

Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and the right to a share of production.

Workover. Operations on a producing well to restore or increase production.

West Texas Intermediate ("WTI"). A type of crude oil used as a benchmark in oil pricing and the underlying commodity of NYMEX oil futures contracts.

CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended (the "Securities Act") and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements, other than statements of historical fact included in this report, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward-looking statements. When used in this Annual Report on Form 10-K, 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 "Risk Factors" in Item 1A of Part 1 of this Annual Report on Form 10-K. These forward-looking statements are based on management's current beliefs as of the date of this Annual Report on Form 10-K, based on currently available information, as to the outcome and timing of future events.

Forward-looking statements may include statements about:

- our ability to realize the anticipated benefits of the White Wolf Acquisition (as defined in Item 1. Business - Recent Activity);
- 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 development program;
- our realized oil, natural gas and NGL prices;
- the timing and amount of our future production of oil, natural gas and NGLs;
- our hedging strategy and results;
- 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;
- general economic conditions;
- credit markets;
- uncertainty regarding our future operating results; and
- our plans, objectives, expectations and intentions contained in the Annual Report on Form 10-K that are not historical.

You should not place undue reliance on these forward-looking statements. These forward-looking statements are subject to a number of risks, uncertainties and assumptions, including but not limited to those risks described under "Risk Factors" in Item 1A of Part 1 of this Annual Report on Form 10-K. Moreover, we operate in a very competitive and rapidly changing environment. New risks emerge from time to time. It is not possible for our management to predict all risks, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements we may make.

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

Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this Annual Report on Form 10-K are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved or occur, and actual results could differ materially and adversely from those anticipated or implied by the forward-looking statements.

All forward-looking statements, expressed or implied, included in this Annual Report on Form 10-K 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 Annual Report on Form 10-K.

PART I

ITEM 1. BUSINESS

Corporate History

Rosehill Resources Inc. (the “Company,” “Rosehill Resources,” “we,” “us,” or “our”) was originally incorporated in Delaware on September 21, 2015 as a special purpose acquisition company under the name KLR Energy Acquisition Corporation ("KLRE") for the purpose of effecting a merger, capital stock exchange, asset acquisition, stock purchase, reorganization or similar business combination involving us and one or more businesses.

On March 16, 2016, KLRE consummated its initial public offering of units ("Units"), each consisting of one share of Class A common stock, par value $0.0001 per share (“Class A Common Stock”), and one warrant (“Public Warrant”). On April 27, 2017, KLRE acquired a portion of the equity of Rosehill Operating Company, LLC ("Rosehill Operating"), an entity into which Tema Oil & Gas Company (“Tema”), a wholly owned subsidiary of Rosemore, Inc. (“Rosemore”), contributed certain assets and liabilities (the “Transaction”). At the closing of the Transaction, KLRE became the sole managing member of Rosehill Operating, and KLRE changed its name to Rosehill Resources Inc.

Immediately following the Transaction, we owned approximately 16% of the Rosehill Operating Common Units and Tema owned the remaining 84%. As of December 31, 2017, after giving effect to the conversion of a portion of the Company's Series A preferred stock into common stock and the corresponding conversion of Rosehill Operating Series A preferred units into Rosehill Common Units, we own approximately 17% of Rosehill Operating’s common equity and Tema owns the remaining 83%.

Our Class A Common Stock, Units and Public Warrants trade on The NASDAQ Capital Market ("NASDAQ") under the ticker symbols “ROSE,” “ROSEU” and “ROSEW,” respectively.

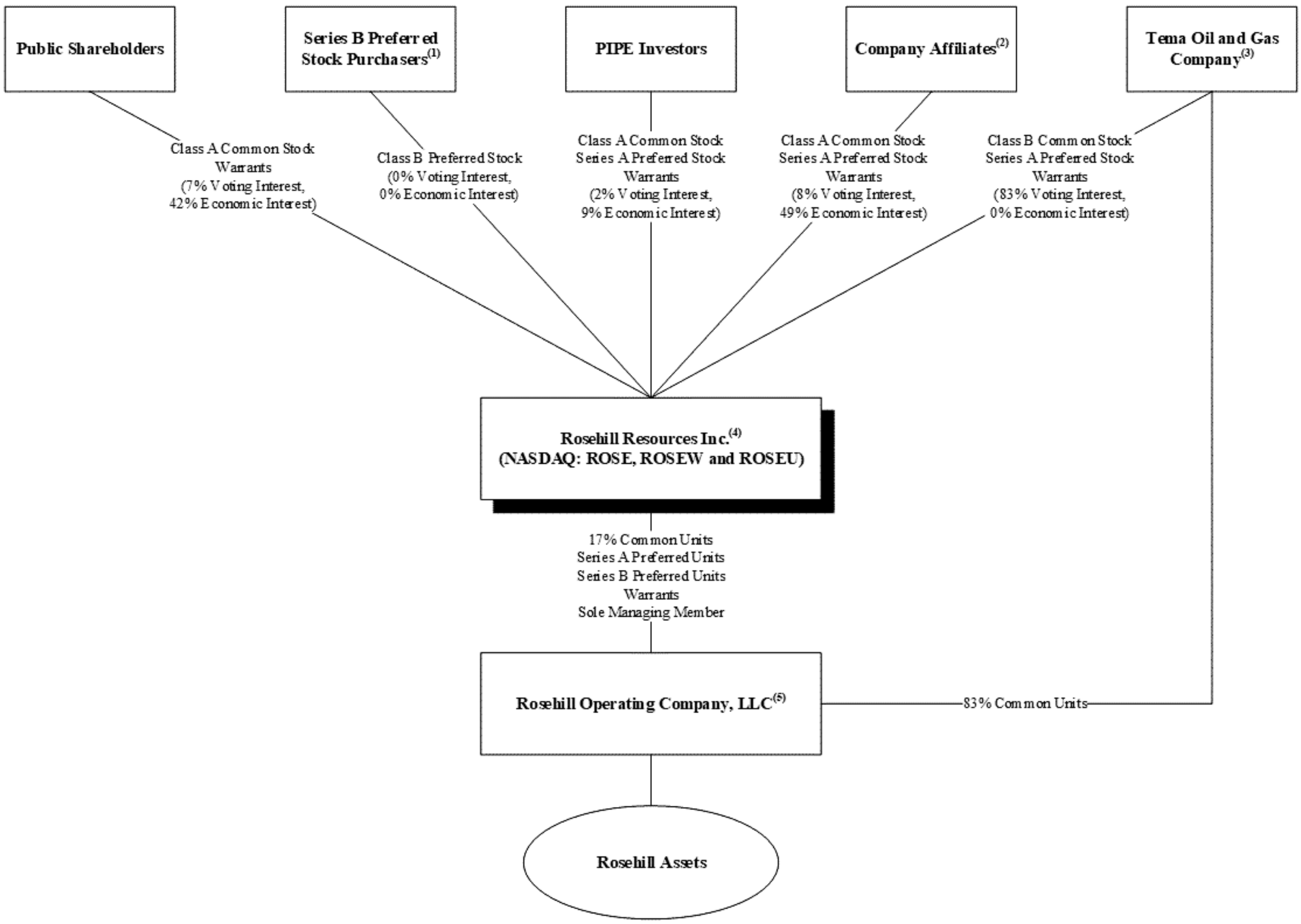
Presentation of Financial and Operating Data

The consolidated financial results of the Company consist of the financial results of Rosehill Resources, Inc. and Rosehill Operating, its consolidated subsidiary. Because Tema has effective control of the combined company before and after the consummation of the Transaction on April 27, 2017 through its majority voting interest in Rosehill Operating and the Company, respectively, the Transaction was structured as a reverse recapitalization. As a result, the reports filed by the Company subsequent to the Transaction are prepared “as if” Rosehill Operating is the predecessor and legal successor to the Company. The historical operations of Rosehill Operating are deemed to be those of the Company. Thus, the financial statements included in this report reflect:

- the historical operating results of Rosehill Operating prior to the Transaction;
- the combined results of the Company and Rosehill Operating following the Transaction;
- the assets and liabilities of Rosehill Operating at their historical cost; and
- the Company’s equity and earnings per share for all periods presented.

Organizational Structure

The following diagram illustrates the current ownership structure of the company:



(1) "Series B Preferred Stock Purchasers" refers to certain private funds and accounts managed by EIG Global Energy Partners, LLC.

(2) "Company Affiliates" refers to KLR Energy Sponsor, LLC, certain of our current and former directors and officers, and certain of our shareholders who own greater than 10% of the Company's common stock.

(3) Includes Class B Common Stock, Series A Preferred Stock and warrants held by Tema Oil and Gas Company.

(4) The economic and voting interests set forth above do not take into account (i) the exercise of outstanding warrants for shares of Class A Common Stock, (ii) the future issuance of shares of Class A Common Stock under the Rosehill Resources Inc. 2017 Long Term Incentive Plan or (iii) the conversion of Series A Preferred Stock into shares of Class A Common Stock or the redemption of Rosehill Operating Common Units (and corresponding shares of Class B Common Stock) for shares of Class A Common Stock.

(5) In connection with the conversion of our remaining Series A Preferred Stock into Class A Common Stock, the Rosehill Operating Series A preferred units owned by us will convert into Rosehill Operating Common Units and, on an as-converted basis, we will own approximately 33% of the Rosehill Operating Common Units.

Our Business

We are an independent oil and natural gas company focused on the acquisition, exploration, development, and production of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin. The Permian Basin is located in West Texas and Southeastern New Mexico and is comprised of three primary sub-basins; the Midland Basin, the Central Basin Platform and the Delaware Basin. Since the sale of our Barnett Shale assets during the fourth quarter of 2017, our assets are concentrated within the Delaware Basin, and we divide our operations into two core areas: the Northern Delaware Basin and the Southern Delaware Basin.

Our sole material asset is our interest in Rosehill Operating. As the sole managing member of Rosehill Operating, we, through our officers and directors, are responsible for all operational, management and administrative decisions relating to Rosehill Operating' s business without the approval of any other member, unless otherwise specified in the Second Amended and Restated Limited Liability Company Agreement of Rosehill Operating (the "Second Amended LLC Agreement").

Our management team has significant experience identifying, acquiring and developing unconventional oil and natural gas assets with the objective of being a returns-oriented pure-play Delaware Basin company focusing on (i) acreage with reduced development risk as a result of being in proved areas within the vicinity of other successful wells, (ii) stacked pay zones, including Brushy Canyon, Avalon/1st Bone Spring, 2nd Bone Spring, 3rd Bone Spring, Upper Wolfcamp A (X/Y), Lower Wolfcamp A, and Wolfcamp B, and (iii) application of geology, optimizing well process improvements and well returns. We believe these characteristics enhance our horizontal production capabilities, recoveries and economic results.

Recent Events

Credit Agreement

On March 28, 2018, we entered into an Amended and Restated Credit Agreement (the "New Credit Agreement") by and among us, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and certain other financial institutions party thereto, as lenders. The New Credit Agreement amends and restates in its entirety the original Credit Agreement entered into on April 27, 2017 and amended on December 8, 2017. Pursuant to the New Credit Agreement, the lenders party thereto have agreed to provide us with a $500 million secured reserve-based revolving credit facility with a current borrowing base of $150 million. The maturity date of the New Credit Agreement is August 31, 2022. The maturity date will be automatically extended to March 2023 upon the payment in full of the Second Lien Notes. The borrowing base will be redetermined semi-annually, with the lenders and us each having the right to one interim unscheduled redetermination between any two consecutive semi-annual redeterminations. The first scheduled redetermination date is August 1, 2018 and then beginning in 2019 each April 1 and October 1 thereafter.

White Wolf Acquisition

On December 8, 2017 (the "White Wolf Closing Date"), we acquired mineral rights and royalty interest to 4,565 net acres and other associated assets and interests in the Southern Delaware Basin (the "White Wolf Acquisition") for approximately $77.6 million in cash, subject to customary purchase price adjustments, pursuant to a Purchase and Sale Agreement (the "PSA") from certain sellers named therein (the "Sellers"). Subject to certain conditions under the PSA, until March 8, 2018, Rosehill Operating was obligated to acquire additional oil and natural gas leases located within a certain designated area in the Delaware Basin (the "Designated Area") from the Sellers for additional consideration of up to $80 million in cash in the aggregate. Such additional oil and natural gas leases (subject to certain selection criteria set forth in the PSA) include all oil and natural gas leases owned by any Seller (or its affiliates) within the Designated Area as of October 24, 2017 (the "Execution Date") but were not included in the initial 4,565 net acres acquired on the White Wolf Closing Date and any oil and natural gas lease acquired by any Seller (or its affiliates) during the period starting on the Execution Date and ending on March 8, 2018 (the "Additional Interests").

On December 21, 2017, we acquired from the Sellers additional mineral rights and royalty interest to 1,940 net acres and other associated assets and interest in the Southern Delaware Basin for $39.0 million. The option to purchase Additional Interests in the Designated Area expired on March 8, 2018. We did not acquire any additional acreage.

Private Placement of Series B Redeemable Preferred Stock and Senior Secured Second Lien Notes

On the White Wolf Closing Date, we also secured financing for the transaction from certain private funds and accounts managed by EIG Global Energy Partners, LLC (collectively, "EIG") through the issuance and sale (i) by us of 150,000 shares of 10.000% Series B Redeemable Preferred Stock, par value $0.0001 per share (the "Series B Preferred Stock") for an aggregate purchase price of $150.0 million and (ii) by Rosehill Operating of $100.0 million in aggregate principal amount of 10.00% Senior Secured Second Lien Notes due January 31, 2023 (the "Second Lien Notes"). We have the option, subject to certain conditions, to issue and sell from time to time up to an additional 50,000 shares of Series B Preferred Stock for a purchase price of $1,000 per share of Series B Preferred Stock. Such option became exercisable by us on March 8, 2018, and terminates on December 8, 2018. For a discussion of our Series B Preferred Stock, read Note 10 - 10% Series B Redeemable Preferred Stock in Item 8 of Part II. For a discussion of the Second Lien Notes, read Note 8 - Long term debt in Item 8 of Part II.

The proceeds received from the issuance of the Series B Preferred Stock and the Second Lien Notes were used to fund the White Wolf Acquisition, to fully repay all amounts outstanding under our revolving credit facility, and to pay related financing costs. The remaining proceeds and any proceeds received from any future issuance of the additional 50,000 shares of Series B Preferred Stock, will be used to fund operations and capital development.

Barnett Shale Divestiture

On November 2, 2017, we announced the closing of the sale of Barnett Shale assets (the "Barnett Shale Asset Sale") for approximately $7.1 million. After customary purchase price adjustments, the net purchase price was approximately $6.5 million. At the time of sale, production from the Barnett Shale assets was approximately 675 net Boe per day.

Our Operations

We operate in one industry segment, which is the exploration, development and production of oil and natural gas, and all operations are conducted in the United States. Consequently, we currently report a single reportable segment. See the notes to our consolidated financial statements for financial information about this reportable segment. Our future development will be focused predominately on horizontal development drilling in both our core acreage areas in the Northern Delaware Basin and the Southern Delaware Basin. We are currently operating two horizontal rigs and have one frac crew under contract.

Since 2012, we have drilled 46 gross horizontal wells in the Delaware Basin with a continuing drop in drilling times and an increase in operational capabilities and efficiencies. In late December 2017, our production exceeded 10,000 net barrels of oil equivalent per day, an increase of over 89% as compared to the daily average of the third quarter of 2017. We have assembled a multi-year inventory of horizontal development and exploration projects, including projects to further evaluate the regional extent and multi-pay potential of our assets. As of December 31, 2017, our portfolio included 39 gross operated producing horizontal wells and 3 gross operated horizontal wells that are completed but not yet producing in the Northern Delaware Basin and working interests in approximately 14,762 gross acres in the Northern and Southern Delaware Basin with an inventory of 530 gross operated and non-operated potential horizontal drilling locations.

We have identified 480 gross operated and 50 gross non-operated potential horizontal drilling locations, including 30 locations associated with proved undeveloped reserves as of December 31, 2017, in up to ten formations from Brushy Canyon down through the Wolfcamp B. As of December 31, 2017, 32 of our gross operated potential horizontal drilling locations in the Northern Delaware Basin were uneconomic using Securities and Exchange Commission (“SEC”) pricing assumptions. We believe that development drilling of our identified gross operated potential horizontal drilling locations, together with an increased focus on maximizing the value of existing assets by optimizing completions, reducing horizontal drilling costs, efficiently building out facilities, and reducing operating costs, will allow us to grow our production and reserves. We also intend to grow our production and reserves through acquisitions that meet certain strategic and financial objectives.

The table below sets forth our identified potential operated horizontal drilling locations for both of our core areas in the Delaware Basin by formation as of December 31, 2017. As we continue to delineate our Southern Delaware Basin acreage position and determine ultimate well spacing, we believe additional potential locations may be identified, including in the Wolfcamp C and Woodford formations.

Target Formation:	Operated Potential Horizontal Drilling Locations (1)(2)(3)(4) Gross	Net
Brushy Canyon	33	30
Upper Avalon	10	10
Lower Avalon / 1st Bone Spring	45	41
2nd Bone Spring Shale	19	19
2nd Bone Spring Sand	61	56
3rd Bone Spring Shale	19	19
3rd Bone Spring Sand	50	44
Wolfcamp A (X/Y)	70	63
Lower Wolfcamp A	80	71
Wolfcamp B	93	85
Total Horizontal Locations (5)	480	438

(1) Our inventory of gross operated potential horizontal drilling locations assumes four to six wells per 640-acre section within each of the ten formations, with the number of prospective formations varying from tract to tract depending on the geology of the specific area.

(2) Our estimated drilling locations are based on well spacing assumptions and the evaluation of our horizontal drilling results as well as results of other operators in the area, combined with our interpretation of available geologic and engineering data. In particular, we have analyzed and interpreted well results and other data acquired through our participation in the drilling of a vertical well that penetrated all of our targeted horizontal formations. In addition, to evaluate the prospects of our horizontal acreage, we have performed open-hole and mud log evaluations, core analysis, and drill cuttings analysis, and acquired and interpreted modern 3-D seismic data.

(3) Our identified gross operated potential horizontal drilling locations are located on operated and non-operated acreage. We will operate approximately 91% of our 530 identified gross potential horizontal drilling locations.

(4) The drilling locations that we actually drill will depend on the availability of capital, regulatory approvals, seasonal restrictions, commodity prices, costs, actual drilling results and other factors. Any drilling activities we are able to conduct on these identified potential horizontal drilling locations may not be successful and may not result in our ability to add additional proved reserves to our existing proved reserves. Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that could adversely affect our business, financial condition and results of operations. The identified gross potential horizontal 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 capital that would be necessary to drill such locations.

(5) Includes PUD and unproved locations for our leasehold in the Northern Delaware Basin and unproved locations in the Southern Delaware Basin.

We expect to drill between 50 and 54 wells in 2018, completing between 42 and 46 wells. As of December 31, 2017, we had 5 drilled uncompleted wells (“DUCs”) and expect to exit 2018 with 12 to 16 DUCs.

Our locations

Advanced petrophysical logs from the vertical portions of our wells, sidewall cores, and seismic data are being utilized to guide our horizontal development of the area. The use of seismic data has resulted in a better understanding of our leasehold’s geology relative to other parts of the basin. The depth to the top of the Wolfcamp from a representative well central to our leasehold is approximately 11,500 feet true vertical depth. The gross thickness of the potential pay section from the top of the Brushy Canyon formation through the base of the Wolfcamp B is approximately 4,500 feet, an attractive thickness for development with multiple horizontal landing formations. We believe that the combination of these conditions will allow us to achieve superior results during the development of our leasehold.

Historically, our horizontal drilling has been widespread across the majority of our lease acreage. We have established commercial production in seven distinct formations in the Delaware Basin in: the Upper Avalon, Lower Avalon, 2nd Bone Spring Sand, 3rd Bone Spring Sand, Upper Wolfcamp A (X/Y), Lower Wolfcamp A and Wolfcamp B. In addition, offset operators have drilled and are producing in all ten formations-from Brushy Canyon down through the Wolfcamp B, enabling us to evaluate our acreage across various geographic areas and stratigraphic formations. As of December 31, 2017, approximately 51% of our total net operated acreage was either held by production or under continuous drilling provisions. Offset operator activity within the 3rd Bone Spring Sand and the Wolfcamp formations as well as our recent successful Wolfcamp drilling program has been a catalyst for Rosehill Operating to generate a development program focused on the 3rd Bone Spring Sand, Upper Wolfcamp A (X/Y), Lower Wolfcamp A and Wolfcamp B formations. We will closely monitor this offset activity and adjust our future development plans with information and best practices learned from other operators.

Completion design and our effective execution are the predominant factors that dictate relative well performance in an area or zone. We have an evolving completion strategy that includes methodical adjustments of parameters, testing of different well designs on adjacent locations with similar rock characteristics, constant monitoring and re-evaluation of results and ultimately tailoring completions to the conditions specific to an area or formation. Our current base completion design is a hybrid fracture stimulation-a combination of slickwater and cross-linked gel. The field-level rate of return is most influenced by incremental improvements in well performance and cost savings; our philosophy is to focus on both parameters, with an emphasis on performance enhancement.

We believe all ten formations represent opportunities across our core acreage and we plan to target those formations in our future drilling program. In this Annual Report on Form 10-K, identified gross potential drilling locations are defined as locations on operated and non-operated leaseholds specifically identified by geologic, engineering and economic assessment. We have estimated our drilling locations based on well spacing assumptions and the evaluation of our operated horizontal drilling results as well as results of other operators in our area. Well performances are combined with interpretation of available geologic and engineering data to generate a development model for the assets. In addition, to evaluate the prospects of our horizontal acreage, we have performed open-hole and mud log evaluations, core analysis, and drill cuttings analysis. We have also acquired 48 square miles of 3-D seismic data that has been used to aid in the interpretation of the prospective formations. The availability of local infrastructure, well performance results, subsurface data and other factors that management may deem relevant, such as easement restrictions and state and local regulations, are considered in determining such locations. The locations that we will actually drill will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs and actual drilling results, among other factors.

Based on our evaluation of applicable geologic and engineering data, we currently have approximately 480 gross (438 net) identified potential operated horizontal drilling locations in multiple horizons on our acreage. We intend to continue to develop our reserves and increase production through development drilling and exploitation and exploration activities on this multi-year project inventory of identified potential drilling locations and through additional acquisitions that meet our strategic and financial objectives, targeting oil-weighted reserves.

Operational facilities

Our development plan includes the development of necessary infrastructure to lower our costs and support our drilling schedule and production growth. We expect to accomplish this goal primarily through contractual arrangements with third-party service providers. Our facilities are generally in close proximity to our well locations and include storage tank batteries, oil/natural gas/water separation equipment, and artificial lift equipment. A crude oil gathering system and a natural gas gathering system are already in place and functioning. We have sufficient gathering systems and pipeline takeaway capacity to continue ongoing and planned operations into 2018. As we continue to drill and develop our Delaware Basin assets, we expect that additional tank battery, water disposal and intra-field gathering lines will be required. We have agreements in place with third-party natural gas and crude oil purchasers and processors to benefit from existing downstream infrastructure. We expect to continue to evaluate the marketplace to obtain additional transportation and gathering options and capacity in the form of new pipeline tie-ins. We and Gateway Gathering and Marketing ("Gateway"), an affiliate of Tema, entered into crude oil gathering and natural gas gathering agreements for a ten-year term. Please read the section entitled “Management’s Discussion and Analysis of Financial Condition and Results of Operations-Related Party Transactions” for further detail.

Marketing and major customers

With respect to core properties we operate in the Northern Delaware Basin, we maintain contracts with Gateway to gather the majority of our production. We deliver crude oil, natural gas, and NGL production to Gateway and Gateway gathers, transports and redelivers the oil, natural gas, and NGLs to certain delivery points. We sell all of our natural gas and NGLs under contracts with terms generally greater than twelve months and all of our oil under contracts with terms generally less than twelve months.

On the Weber 26 Lease in Loving County, Texas, we sell our crude oil to Rio Energy International on a month-to-month basis, and our natural gas to Targa Resources, a midstream gas gathering and transportation company, with a five-year gas purchase contract. Gateway does not provide gathering services on the Weber 26 Lease.

We sell our production to a relatively small number of customers, as is customary in the industry. The following table shows the percentage of sales to each of our major customers relative to our total revenues.

	Year Ended December 31,		
	2017	**2016**	**2015**
Customer			
Gateway	80 %	70 %	54 %
ETC Field Services, LLC	10	17	—
Sunoco Inc.	—	—	13
Enlink Midstream Services, LLC	—	10	11
Regency Energy Partners, LP	—	—	11
Other	10	3	11
Total	100 %	100 %	100 %

The loss of any one or all of our significant customers as a purchaser 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 significant customers as a purchaser would not have a material adverse effect on our financial condition and results of operations because crude oil and natural gas are fungible products with well-established markets and numerous purchasers.

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil, NGL 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 12.5% to 25%, resulting in a net revenue interest to us generally ranging from 75% to 87.5%. As of December 31, 2017, 54% of our net leasehold acreage was held by production.

Transportation

Oil production from our core properties in the Northern Delaware Basin is delivered to our production facilities and then transported through Gateway’s Raven Pipeline to the interconnection between Raven Pipeline and Plains Pipeline. In connection with the Transaction, we entered into a Crude Oil Gathering Agreement with Gateway, which became effective on April 27, 2017 and will expire on April 27, 2027. Upon expiration, the Crude Oil Gathering Agreement will continue on a year-to-year basis until terminated by either party.

Our natural gas production from our core properties in the Northern Delaware Basin is delivered to our production facilities and then transported through Gateway’s Loving County Gas System ("LCGS") to the interconnection between LCGS Pipeline and our purchasers. Gateway provides transportation on the LCGS pipeline. We do not control Gateway's or any other third party's transportation facilities. In connection with the Transaction, we entered into a Gas Gathering Agreement with Gateway, which became effective on April 27, 2017 and will expire on April 27, 2027. Upon expiration the Gas Gathering Agreement will continue on a year-to-year basis until terminated by either party.

On the Weber 26 Lease located in the Northern Delaware Basin, our natural gas production is transported to Targa Resources, a midstream gas gathering and transportation company, with a five-year gas purchase contract. Gateway does not provide gathering services on the Weber 26 Lease.

During the further development of our properties in the Northern and Southern Delaware Basins, we expect to consider all gathering and delivery infrastructure options in the areas of our production. Gateway has a right of first refusal to build gathering and delivery infrastructure for our properties in the Northern Delaware Basin.

For descriptions of the Crude Oil Gathering Agreement and Gas Gathering Agreement, please read the section entitled "Management's Discussion and Analysis of Financial Condition and Results of Operations - Related Party Transactions".

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. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas market prices. 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, primarily based on price. Changes in the availability or price of oil and natural gas or other forms of energy, as well as business conditions, conservation, and the ability to convert to alternate fuels and other forms of energy may affect the demand for oil and natural gas. 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 future federal, state, and local laws and regulations more easily than we can, which would adversely affect our competitive position. Please see "Risk Factors - Risks Related to Our 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."

Seasonality of business

Demand for oil and natural gas generally decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. Weather conditions affect the demand for and prices of, oil, natural gas and NGLs. Due to these and other seasonal fluctuations, results of operations for quarterly periods may not be indicative of the results that may be realized on an annual basis. Such seasonal anomalies can also pose challenges for meeting our well drilling objectives and may increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay or temporarily halt our operations.

Operational hazards and insurance

The oil and natural gas industry involves a variety of operating risks, including, but not limited to, the risk of fire, explosions, blow outs, pipe failures and, in some cases, abnormally high-pressure formations which could lead to environmental hazards such as oil spills, natural gas leaks and the discharge of toxic gases. If any of these should occur, we could incur legal defense costs and could be required to pay amounts due to injury, loss of life, damage or destruction to property, natural resources and equipment, pollution or environmental damage, regulatory investigation and penalties and suspension of operations.

In accordance with what we believe to be industry practice, we maintain insurance against some, but not all, of the operating risks to which our business is exposed. We currently have insurance policies for certain property damages, control of well protection, general liability, commercial automobile, workers compensation, pollution liability (claims made coverage with a policy retroactive date), excess umbrella liability and other coverages.

Our insurance is subject to exclusion and limitations, and there is no assurance that such coverage will fully or adequately protect us against liability from all potential consequences, damages and losses. Any of these operational hazards could cause a significant disruption to our business. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows. See Item 1A. "Risk Factors - Risks Related to the Oil and Natural Gas Industry and Our Business-Operating hazards and uninsured risks may result in substantial losses and could prevent us from realizing profits."

We reevaluate the purchase of insurance, policy terms and limits annually. Future insurance coverage for our industry could increase in cost and may include higher deductibles or retentions. In addition, some forms of insurance may become unavailable in the future or unavailable on terms that we believe are economically acceptable. No assurance can be given that we will be able to maintain insurance in the future at rates that we consider reasonable and we may elect to maintain minimal or no insurance coverage. We may not be able to secure additional insurance or bonding that might be required by new governmental regulations. This may cause us to restrict our operations, which might severely impact our financial position. The occurrence of a significant event, not fully insured against, could have a material adverse effect on our financial condition and results of operations.

Generally, we also require our third-party vendors to sign master service agreements in which they agree to indemnify us for injuries and deaths of the service provider's employees as well as contractors and subcontractors hired by the service provider.

Regulation of the Oil and Natural Gas Industry

Our operations are substantially affected by federal, state and local laws and regulations. Failure to comply with these 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, 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, 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 the United States Congress ("Congress"), the states, the Federal Energy Regulatory Commission (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.

Regulation of oil and natural gas production

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 property interests in jurisdictions that regulate drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the source and disposal of water used in the drilling and completion process, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. Our operations are also subject to various conservation laws and regulations, including 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 limit or 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. These laws also govern various 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 may limit the amount of oil and natural gas that we can produce from our wells and 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, these jurisdictions impose a production or severance tax with respect to the production and sale of oil, NGLs and natural gas within its jurisdiction. 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 oil sales and transportation

Sales of oil, condensate and NGLs are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future. 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. FERC regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. 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. 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. In December 2015, H.R. 2029 was signed into law which lifted a ban on the export of crude oil from the United States. This will enable U.S. oil producers the flexibility to seek new markets and export oil into the global marketplace.

Regulation of natural gas sales and transportation

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.

The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act of 1938, as amended ("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 amends the NGA to add an anti-market manipulation provision that makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC Pursuant to the EP Act of 2005, FERC promulgated regulations that 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, use, or employ any device, scheme, or artifice to defraud; (ii) make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (iii) engage in any act or practice that operates as a fraud or deceit upon any person. The 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 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" gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the Annual Reporting requirements described below.

The EP Act of 2005 also 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 NGA 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. Under FERC's regulations, wholesale buyers and sellers of more than 2.2 million MMBtus of physical natural gas in the previous calendar year, including natural gas producers, gatherers and marketers, are now 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, and 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 transporting gas to point of sale locations may increase. we believe that the third-party natural gas pipelines on which our gas is gathered 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 those gathering facilities 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.

For 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 U.S. Commodity Futures Trading Commission. The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures or derivative contracts 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, as well as any manipulative or deceptive device or contrivance in connection with any contract of sale of any commodity in interstate commerce or futures or derivative contract on such commodity. Should we violate the anti-market manipulation laws and regulations, they 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 ships our 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 revenue 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 it 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 exploration, development and production operations are subject to stringent federal, regional, state and local laws and regulations governing the discharge of materials into the environment or otherwise relating to occupational health and safety, or the protection of the environment and natural resources. Numerous federal, state and local governmental agencies, such as the U.S. Environmental Protection Agency ("EPA"), issue regulations that often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for non-compliance. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, ecologically or seismically sensitive areas, and other protected areas, require action to prevent or remediate pollution from current or former operations, such as plugging abandoned wells or closing pits, result in the suspension or revocation of necessary permits, licenses and authorizations, require that additional pollution controls be installed and impose substantial liabilities for pollution resulting from our operations or related to our owned or operated facilities. Liability under such laws and regulations is often strict (i.e., no showing of “fault” is required) and can be joint and several. Moreover, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the release of hazardous substances, hydrocarbons or other waste products into the environment. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly pollution control or waste handling, storage, transport, disposal or cleanup requirements could materially adversely affect our operations and financial position, as well as the oil and natural gas industry in general. Our management believes that we are in substantial compliance with applicable environmental laws and regulations and we have not experienced any material adverse effect from compliance with these environmental requirements. This trend, however, may not continue in the future.

Regulation of 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. Although petroleum substances such as crude oil and natural gas are excluded from the definition of hazardous substances under CERCLA, various substances used in drilling and production operations are not covered by this exclusion and releases of these non-excluded substances or petroleum substances could give rise to CERCLA liability. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances or petroleum released into the environment. We are only able to directly control the operation of those wells for which we act as operator. Notwithstanding our lack of direct control over wells operated by others, the liability of an operator other than us for releases may, in certain circumstances, be attributed to us. We generate materials in the course of our operations that may be regulated as hazardous substances, but we are unaware of any liabilities for which it may be held responsible that would materially and adversely affect us.

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, in the course of their operations, we may 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 or are listed hazardous wastes. In addition, even wastes excluded from the definition of hazardous waste may be regulated by the EPA or state agencies under state laws or other federal laws. Moreover, it is possible that those particular oil and natural gas development and production wastes now excluded from the definition of hazardous wastes could be classified as hazardous wastes in the future. For example, from time to time various environmental groups have challenged the EPA's exclusion of certain oil and gas wastes from RCRA. In one such challenge, the U.S. District Court for the District of Columbia entered a consent decree requiring EPA to evaluate the exclusion and, by March 2019, to either sign a notice of proposed rulemaking revising the regulations excluding oil and gas wastes or sign a determination that revision of the exclusion is not necessary. A loss of the RCRA exclusion for drilling fluids, produced waters and related wastes, if the EPA were to eliminate the exclusion, 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. Although the costs of managing hazardous waste may be significant, we do not believe that our costs in this regard are materially more burdensome than those for similarly situated companies.

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.

Regulation of 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. The 2015 rule was previously stayed nationwide to determine whether federal district or appellate courts had jurisdiction to hear cases challenging the new rules. The EPA and the Corps issued a proposed rulemaking in June 2017 to repeal the June 2015 rule, and announced their intent to issue a new rule defining the Clean Water Act's jurisdiction. Recently, in January 2018, the U.S. Supreme Court issued a decision finding that jurisdiction resides with the federal district courts; following which, the previously-filed district court cases will be allowed to proceed. Following the Supreme Court's decision, the EPA and the Corps issued a final rule in January 2018 staying implementation of the 2015 rule for two years while the agencies reconsider the rule. Multiple states and environmental groups have challenged the stay. As a result of these recent developments, future implementation of the June 2015 rule is uncertain. To the extent any revised 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. 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 pollutants in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages.

In addition, 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," for on-site storage of significant quantities of oil. We believe that we maintain all required discharge permits necessary to conduct our operations and further believe we are in substantial compliance with the terms thereof.

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.

Regulation of air emissions

The federal Clean Air Act and comparable state laws restrict the emission of air pollutants from many sources, such as, for example, 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 Standards ("NAAQS") for ozone from 75 to 70 parts per billion. In November 2017, the EPA published a list of areas that are in compliance with the new ozone standard and, separately in December 2017, issued responses to state recommendations for designating non-attainment areas. States have the opportunity to submit new air quality monitoring to EPA prior to EPA finalizing any non-attainment designations. The EPA intends to issue final attainment status designations during the first half of 2018. State implementation of the revised NAAQS could result in stricter permitting requirements or could delay or limit 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 June 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 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. 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. However, we do not believe that compliance with such requirements will have a material adverse effect on our operations.

Regulation of greenhouse gas emissions ("GHG")

In response to findings that emissions of carbon dioxide, methane, and other GHG 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 GHG emissions from certain large stationary sources that otherwise require such permits for non-GHG emissions. 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 June 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 rule includes 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. However, the agency proposed a rulemaking in June 2017 to stay the requirements for a period of two years and revisit implementation of these methane standards in their entirety. The EPA has not yet published a final rule but, as a result of these developments, future implementation of the 2016 standards is uncertain at this time. To the extent implemented, compliance with these rules would 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 would also likely require hiring additional personnel to support these activities or the engagement of third-party contractors to assist with and verify compliance. New rules related to the reduction of methane and other GHG emissions could result in increased compliance costs on our operations.

There have not been significant legislative proposals to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional programs and initiatives have been enacted or are being considered that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs, direct taxation of carbon emissions, or that promote the use of less carbon-intensive fuels. These programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. At the international level, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France that requires member countries to review and ''represent a progression'' in their intended nationally determined contributions, which set GHG emission reduction goals every five years beginning in 2020. The Paris Agreement entered into force in November 2016. Although this agreement does not create any binding obligations for nations to limit their GHG emissions, it does include pledges from participating nations to voluntarily limit or reduce future emissions. In June 2017, President Trump stated that the United States would withdraw from the Paris Agreement, but may enter into a future international agreement related to GHGs. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process is uncertain and/or the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time.

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. Substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce and lower the value of our reserves. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and gas will continue to represent a substantial percentage of global energy use over that time. Finally, it should be noted that some scientists have concluded that 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, droughts, and other climatic events. Our operations are onshore and not located in coastal or flood-prone regions of the United States, but if any such effects were to occur at our locations, these effects have the potential to cause physical damage to our assets or affect the availability of water for our operations and thus could have a material adverse effect on our operations.

Regulation of hydraulic fracturing

Hydraulic fracturing is an important common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations, including shales. The process, which involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production, is typically regulated by state oil and natural gas commissions. However, legislation has been proposed in recent sessions of Congress to amend the Safe Drinking Water Act ("SDWA") to repeal the exemption for hydraulic fracturing from the definition of "underground injection," to require federal permitting and regulatory control of hydraulic fracturing, and to require disclosure of the chemical constituents of the fluids used in the fracturing process. Furthermore, several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has recently taken the position that hydraulic fracturing with fluids containing diesel fuel is subject to regulation under the Underground Injection Control program, specifically as "Class II" Underground Injection Control wells under the Safe Drinking Water Act. In addition, the EPA plans to develop a Notice of Proposed Rulemaking by June 2018, which would describe a proposed mechanism - regulatory, voluntary, or a combination of both - to collect data on hydraulic fracturing chemical substances and mixtures. Also, in June 2016, the EPA published a final rule prohibiting the discharge of wastewater from onshore unconventional oil and gas extraction facilities to publicly owned wastewater treatment plants.

The EPA has issued final regulations under the federal Clean Air Act that establish air emission controls for oil and natural gas production and natural gas processing operations. Specifically, the EPA's rule package includes New Source Performance standards to address emissions of sulfur dioxide and volatile organic compounds and a separate set of emission standards to address hazardous air pollutants frequently associated with oil and natural gas production and processing activities. These rules require a 95% reduction in volatile organic compounds emitted from these activities by requiring the use of reduced emission completions or "green completions" on new hydraulically-fractured wells. The rules also establish specific new requirements regarding emissions from compressors, controllers, dehydrators, storage tanks and other production equipment. These standards, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or mandate the use of specific equipment or technologies to control emissions.

The EPA has also released a study examining the potential for hydraulic fracturing activities to impact drinking water resources, finding that, under some circumstances, the use of water in hydraulic fracturing activities can impact drinking water resources. Also, on February 6, 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and minimizing the potential for significant injection-induced seismic events.

Several states, including Texas, and local jurisdictions, have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances, impose more stringent operating standards and/or require the disclosure of the composition of hydraulic fracturing fluids. For example, the Texas Railroad Commission has adopted rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. The Texas Railroad Commission has also adopted disposal well rule amendments designed, among other things, to require applicants for new disposal wells that will receive non-hazardous produced water and hydraulic fracturing flowback fluid to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed new disposal well. The disposal well rule amendments also clarify the Texas Railroad Commission's authority to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The Texas Railroad Commission has used this authority to deny permits for waste disposal wells.

There has been increasing public controversy regarding hydraulic fracturing with regard to the use of fracturing fluids, induced seismic activity, impacts on drinking water supplies, use of water and the potential for impacts to surface water, groundwater and the environment generally. A number of lawsuits and enforcement actions have been initiated across the country implicating hydraulic fracturing practices. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal, state or local level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal, state or local laws governing hydraulic fracturing.

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 or proposed for listing are known to 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. The agency missed this deadline and continues to review species for listing under the ESA. Also, in the past, the federal government has 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. However, in December 2017, the Department of Interior issued a new opinion revoking its prior enforcement policy and concluded that an incidental take is not a violation of the Migratory Bird Treaty Act. 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 a 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 ongoing operations. These permits are generally subject to protest, appeal, or litigation, which, in certain cases, can delay or halt projects and cease production or operation of wells, pipelines and other operations.

Employees

As of December 31, 2017, we had 48 full-time employees. We also hire independent contractors and consultants on an as needed basis in land, technical, regulatory and other disciplines who assist with specific tasks and perform various field and other services. None of our employees are represented by labor unions or covered by collective bargaining agreements, and we have not experienced any strikes or work stoppages. Our future success will depend partially on our ability to identify, attract, retain and motivate qualified personnel. We consider our relations with our employees to be satisfactory.

Principal Executive Offices and Internet Address

Our principal executive offices are located at 16200 Park Row, Suite 300, Houston, Texas 77084, and our telephone number at that address is (281) 675-3400.

Our website address is www.rosehillresources.com. We make our periodic reports and other information filed with or furnished to 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 Annual Report filed on Form 10-K.

Available information

We are required to file quarterly and annual reports, current reports, proxy statements and other information with the SEC. You may read and copy any documents filed by us with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. Our filings with the SEC are also available to the public at the SEC's website at http://www.sec.gov. Our common stock is listed and traded on the NASDAQ Capital Market under the symbol "ROSE."

We also make available on our website (http://www.rosehillresources.com) all documents that we file with the SEC, free of charge, as soon as reasonably practicable after we electronically file such material with the SEC. Our Code of Ethics and Corporate Governance Guidelines and the charters of our audit committee, compensation committee and nominating and governance committee are also available on our website and in print free of charge to any stockholder who requests them. Requests should be sent by mail to our corporate secretary at our corporate offices at 16200 Park Row, Suite 300, Houston, Texas 77084. Information contained on our website is not incorporated by reference into this Annual Report on Form 10-K. We intend to disclose on our website any amendments or waivers to our Code of Ethics that are required to be disclosed pursuant to Item 5.05 of Form 8-K.

ITEM 1A. RISK FACTORS

The nature of our business activities subjects us to certain hazards and risks. The following risks and uncertainties, together with other information set forth in this Annual Report on Form 10-K, should be carefully considered by current and future investors in our securities. These risks and uncertainties are not the only ones we face. Additional risks and uncertainties presently unknown to us or currently deemed immaterial also may impair our business operations. The occurrence of one or more of these risks or uncertainties could materially and adversely affect our business, our financial condition, and the results of our operations, which in turn could negatively impact the value of our securities.

Risks Related to Our Operations

Oil, natural gas and NGL prices are volatile. A 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 revenues, profitability, cash flows and future growth, as well as liquidity and ability to access additional sources of capital, depends substantially on prevailing prices for oil, natural gas, and NGLs. A reduction in or sustained lower prices will reduce the amount of oil, natural gas, and NGLs that we can economically produce and may result in impairments of our proved reserves or reduction of our proved undeveloped reserves. Oil, natural gas, and NGL prices also affect the amount of cash flow available for capital expenditures and ability to borrow and raise additional capital.

The markets for oil, natural gas, and NGLs have historically been volatile. For example, since 2014, the WTI spot price for oil declined from a high of $107.95 per barrel in June 2014 to a low of $26.19 per barrel in February 2016 and ended the year at $60.46 per barrel on December 29, 2017 and the NYMEX Henry Hub spot price for natural gas declined from a high of $8.15 per MMBtu in February 2014 to a low of $1.49 per MMBtu in March 2016 and ended the year at $3.69 per MMBtu on December 29, 2017. Likewise, NGLs, which are made up of ethane, propane, isobutane, normal butane and natural gasoline, each of which have different uses and different pricing characteristics, have suffered significant recent declines in realized prices. The price of propane (Mont Belvieu) ranged from a high of $1.70 per gallon in January 2014 to a low of $0.30 per gallon in January 2016 and ended the year at $0.98 per gallon on December 29, 2017, and the price of ethane (Mont Belvieu) ranged from a high of $0.45 per gallon in January 2014 to a low of $0.14 per gallon in December 2016 and ended the year at $0.22 per gallon on December 29, 2017.

The market prices for oil, natural gas, and NGLs depend on factors beyond our control. Some, but not all, of the factors that can cause fluctuation include:

- 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 (“OPEC”), its members and other state-controlled oil companies, including the ability of members of OPEC to agree to and maintain price and production controls;
- the level of global exploration, development and production;
- the level of global inventories;
- the extent to which U.S. shale producers become “swing producers” adding or subtracting to the world supply;
- 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, other natural disasters, and climate change;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels;
- worldwide conservation measures;
- domestic and foreign governmental relations, regulation, and taxes;

- worldwide governmental regulation and taxes;
- U.S. and foreign trade restrictions, regulations, tariffs, agreements, and treaties;
- the level and effect of trading in commodity futures markets, including commodity price speculators and others; and
- political conditions or hostilities and unrest in oil producing regions.

Lower commodity prices will reduce our cash flows and borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in the present value of our reserves and our ability to develop future reserves. Lower commodity prices may also reduce the amount of oil, natural gas and NGLs that we can produce economically and may impact our ability to satisfy our obligations under firm-commitment transportation agreements. We have historically been able to hedge our natural gas production at prices that are significantly higher than current strip prices. However, in the current commodity price environment, our ability to enter into comparable derivative arrangements may be limited.

Using lower prices in estimating proved reserves would likely result in a reduction in proved reserve volumes due to economic limits. While it is difficult to project future economic conditions and whether such conditions will result in impairment of proved property costs, we consider several variables including 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. In addition, sustained periods with oil and natural gas prices at levels lower than current 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. 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 or ability to finance planned capital expenditures.

Our development and acquisition 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 substantial capital expenditures related to development and acquisition projects. We expect to fund our capital expenditures with cash generated by operations, borrowings under the credit agreement, dated April 27, 2017, as amended by the first amendment thereto, dated December 8, 2017 (the “Credit Agreement”), by and among Rosehill Operating and PNC Bank, National Association, as administrative agent and issuing bank, and each of the lenders from time to time party thereto, the New Credit Agreement and through additional issuances of Series B Preferred Stock to EIG; however, financing needs may require an alteration or increase in our capitalization substantially through the issuance of debt or equity or the sale of assets. The issuance of additional indebtedness would require that a portion of the cash flow from our 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 by us would be dilutive to 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 and cost 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 volume 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;
- our ability to borrow under our Credit Agreement (or any replacement credit facility); and
- our ability to access the capital markets.

If cash flow from operations or available borrowings under our Credit Agreement decrease as a result of lower oil, natural gas and NGL prices, operational difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on acceptable terms, if at all. If cash flow from operations or available under existing or anticipated credit facilities are insufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of the 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.

Drilling for oil and natural gas involves numerous and significant risks and uncertainties.

Risks that we face while drilling wells include:

- effects of weather, floods, snowstorms, ice storms, and similar natural conditions, on the drilling location and delivery of materials to the wellsite;
- unforeseen water flows;
- lost circulation of drilling fluids;
- unexpected oil and gas flows into the well bore;
- drill pipe, casing and equipment failure, or loss of equipment in the well;
- failure or inaccuracies of directional drilling measurement devices;
- excessive hole washouts in the Salt/Anhydrite zones resulting in poor surface cement jobs;
- inability to reach the desired drilling zone with conventional bits and drilling techniques;
- failure to land a wellbore in the desired drilling zone;
- inability to stay in the desired drilling zone or being able to run tools and other equipment consistently while drilling horizontally through the formation;

- difficulties in running casing the entire length of the wellbore.

Risks that we face while completing wells include:

- 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. Furthermore, the results of our drilling in new or emerging formations are more uncertain initially than drilling results in areas that are more developed and have a longer history of established production. Newer or emerging formations and areas have limited or no production history and, consequently, we are more limited in assessing future drilling results in these areas. If our drilling results are less than anticipated, the return on our investment for a particular project may not be as attractive as anticipated, and we could incur material write-downs of unevaluated properties and a decline in the value of our undeveloped acreage.

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” below. In addition, our cost of drilling, completing and operating wells is often uncertain.

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 resulting from wastewater disposal, emissions 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 water for hydraulic fracturing activities;

- equipment failures, accidents or other unexpected operational events;

- lack of available gathering facilities or delays in construction of gathering facilities;

- lack of available capacity on interconnecting transmission pipelines;

- adverse weather conditions, including such conditions which are possibly connected to climate change;

- drought conditions limiting the availability of water for hydraulic fracturing, including such conditions as possibly connected to climate change;
- 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.

We may fail to realize the benefits anticipated from the White Wolf Acquisition.

The acreage and other associated assets and interests recently acquired in the White Wolf Acquisition involves potential risks, including, without limitation, inefficiencies and unexpected costs and liabilities. We may be unable to successfully integrate the acquired properties or to realize anticipated revenues or other benefits of the White Wolf Acquisition. Our ability to achieve the anticipated benefits of the White Wolf Acquisition will depend in part upon whether we can integrate the acquired properties into our existing business in an efficient and effective manner. We may not be able to accomplish this integration process successfully. If these risks or other expected costs and liabilities were to materialize, any desired benefits of the White Wolf Acquisition may not be fully realized, if at all, and our future financial performance and results of operations could be negatively impacted.

If the benefits of the White Wolf Acquisition do not meet the expectations of the marketplace, or financial or industry analysts, the market price of our Class A Common Stock may decline.

The market price of our Class A Common Stock may decline as a result of the White Wolf Acquisition if the acquired assets do not perform as expected, or we do not otherwise achieve the perceived benefits of the White Wolf Acquisition as rapidly as, or to the extent, anticipated by the marketplace, or financial or industry analysts. Our assessment of the White Wolf Acquisition properties to date has been limited and does not reveal all existing or potential problems, nor will it permit us to become familiar enough with the properties to assess fully their capabilities and deficiencies. Although we will inspect the acquired properties, inspections may not reveal all title, structural or environmental problems. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

The market price of our Class A Common Stock may decline as a result of the White Wolf Acquisition if, among other things, the integration and development of the acquired properties is unsuccessful or if the expenses, title, environmental and other defects, or transaction costs related to the White Wolf Acquisition are greater than expected or the acquired properties do not yield the anticipated returns. Accordingly, investors may experience a loss from a decreasing stock price and we may not be able to raise future capital, if necessary, in the equity markets.

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

A portion of our oil and natural gas production has historically been hedged in order to protect cash flow from falling prices. The use of these arrangements limits our ability to benefit from increases in the prices of natural gas and oil. As of December 31, 2017, we had open commodity derivative contracts for the months of January 2018 through December 2022 covering a total of 5,624 MBbls of oil and 9,900 MMcf of natural gas. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our commodity derivative.

Commodity derivatives may also expose us to the risk of financial loss in some circumstances, including when:

- production and sales are insufficient to offset losses under the commodity derivatives;
- the counterparty to the commodity derivatives defaults on its contractual obligations;
- there is an increase in the differential between the underlying price in the commodity derivatives and actual prices received;
- issues arise with regard to legal enforceability of such instruments; and
- applicable laws or regulations regarding such instruments are changed.

The use of commodity derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into commodity derivatives that require cash collateral, particularly if commodity prices or interest rates change in a manner averse 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 counterparties, highly volatile oil and natural gas prices and interest rates. In addition, commodity derivatives 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 accurately predict sudden changes, our ability to negate the risk may be limited depending upon market conditions.

During periods of declining commodity prices, our commodity derivative contract receivable positions have generally increased, which has increased 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.

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 oil and natural gas 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 oil and natural gas 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 our estimates 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 estimated reserves is the current market value of such 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. For example, our estimated proved reserves as of December 31, 2017 were, and related standardized measure was, calculated under SEC rules using twelve-month unweighted average first-day-of-the-month prices of $51.34 per barrel of oil (WTI), $31.82 per barrel of NGL (Mont Belvieu), and $2.98 per MMBtu of natural gas (Henry Hub) which, for certain periods in 2017, were substantially higher than the available spot prices. 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.

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

We have 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 potential drilling locations our management has identified will ever be drilled or if we will be able to produce oil or natural gas in commercial qualities 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 December 31, 2017, 480 gross operated potential horizontal drilling locations have been identified on our acreage based on four to six wells per 640-acre section within each of ten formations from the Brushy Canyon through Wolfcamp B formations. As of December 31, 2017, 189 of our Northern Delaware Basin gross operated potential horizontal drilling locations, of which 29 were PUDs, were economic using SEC pricing assumptions. Horizontal lateral effective lengths across our acreage range from 4,000 feet up to 10,000 feet. As a result of the limitations described above, we may be unable to drill many of the identified locations. Further, in connection with the White Wolf Acquisition, we acquired approximately 6,505 net acres in northwestern Pecos County, Texas, which is largely unproven and relatively undrilled compared to other areas in the Delaware Basin. We have no experience drilling in Pecos County. Based on future operations or regulatory changes, we may determine that certain formations cannot be physically or economically exploited or that spacing of wells may have to be changed.

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 development and acquisition 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" above. 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.

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 December 31, 2017, approximately 54% of our total net acreage was either held by production or under continuous drilling provisions. 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 or the leases are renewed. If our leases expire and we are unable to renew the leases, we will lose the 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 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 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.

All of our producing properties are located in the Delaware Basin, a sub-basin of the Permian Basin, in West Texas and New Mexico, 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 December 31, 2017, 100% 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.

In addition to the geographic concentration of our producing properties in the Northern Delaware Basin described above, at December 31, 2017, approximately 71% percent of our proved reserves were attributable to the 3rd Bone Spring, Wolfcamp A (X/Y) and Lower Wolfcamp A formations. This concentration of assets within a small number of producing horizons exposes us to additional risks, such as changes in field-wide rules and regulations that could cause us to permanently or temporarily shut-in all of our wells within a field. There were no proved reserves attributable to the Southern Delaware Basin as of December 31, 2017.

We will not be the operator on all of our acreage or drilling locations, and, therefore, we will not be able to control the timing of exploration or development efforts, associated costs, or the rate of production of any non-operated assets.

We have leased or acquired approximately 11,141 net acres in the Delaware Basin, approximately 91% of which we operate, as of December 31, 2017. As of December 31, 2017, we were the operator on 480 of our 530 identified gross horizontal drilling locations. We expect to operate approximately 100% of, and have an approximate 90% working interest in, the acreage we acquired and expect to operate in the White Wolf Acquisition and believe that the acreage may be prospective for six different shale formations. We will have limited ability to exercise influence over the operations of the drilling locations we do not operate, and the operators of those locations may at any time have economic, business or legal interests or goals that are inconsistent with us. Furthermore, the success and timing of development activities by such operators will depend on a number of factors that will be largely outside of our control, including:

- the timing and amount of capital expenditures;
- the operator's expertise and financial resources;
- the approval of other participants in drilling wells;
- the selection of technology; and

- the rate of production of reserves, if any.

This limited ability to exercise control over the operations and associated costs of some of our non-operated drilling locations could prevent the realization of targeted returns on capital in drilling or acquisition activities.

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

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

The marketability of our production will be dependent upon transportation and other facilities, certain of which we will not control. If these facilities are unavailable, 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. Our oil production is purchased at the wellhead by Gateway, an affiliate of Tema, and transported through Gateway’s Raven Gathering System (“Raven”) pipeline to the interconnection between Raven pipeline and Plains Marketing, LP pipeline. The oil is then transported on a third-party pipeline to Midland, Texas where it is sold. Our natural gas production is transported by Gateway on Gateway’s Loving County Gathering System (“LCGS”) pipeline from the wellhead to the interconnection between LCGS pipeline and ETC Field Services pipeline. The gas is sold by us to the third party (ETC Field Services) at the interconnection between LCGS and ETC Field Services. ETC Field Services transports the gas to our processing facility. In connection with the Transaction, we and Gateway entered into crude oil gathering and natural gas gathering agreements with ten-year terms.

We do not control Gateway’s or the third-party’s transportation facilities and our access to the facilities may be limited or denied. Insufficient production from our wells to support the construction of pipeline facilities by our purchasers or a significant disruption in the availability of 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 or flare natural gas. Any such shut-in, curtailment, or flaring 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.

Multi-well pad drilling may result in volatility in our operating results.

We utilize multi-well pad drilling where practical. Because wells drilled on a pad are not brought into production until all wells on the pad are drilled and completed and the drilling rig is moved from the location, multi-well pad drilling delays the commencement of production, which may cause volatility in our quarterly operating results.

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 have historically obtained 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 and may be required to pay damages to the actual owner of the lease.

Concerns over economic, business or industry conditions may have a material adverse effect on our results of operations, liquidity and financial condition.

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit, the European, Asian and the United States financial markets have contributed to increased economic uncertainty and diminished expectations for the global economy. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the global economy. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates, worldwide demand for petroleum products could diminish further, which could impact the price at which we can sell our production, affect the ability of our vendors, suppliers and customers to continue operations and ultimately adversely impact our results of operations, liquidity and financial condition.

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

As of December 31, 2017, 57% of our total estimated proved reserves were classified as PUDs. Development of these PUDS may take longer and require higher levels of capital expenditures than currently anticipated. For example, primarily as a result of factors outside our control, including a downturn in commodity prices during 2014, we adjusted our development plan to temporarily defer the drilling of certain PUD locations. As a result, no PUDs were converted from undeveloped to developed during 2015 and 2016. As a result of our failure to convert any PUDs during 2015 and 2016, we will have a shorter period of time available to convert such PUDs (due to the requirement to convert PUDs from undeveloped to developed within five years of initial booking). Further delays in the development of our PUDs, increases in costs to drill and develop such reserves or decreases in commodity prices will reduce the value of our estimated PUDs and future 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 if we no longer believe with reasonable certainty that we will develop the PUDs within five years after their initial booking. If we do not drill our PUD wells within five years after their respective dates of booking, we may be required to write-down our PUDs.

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 impairments or write-downs of the carrying values of our properties.

Accounting rules require periodic review of 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. Commodity prices have declined significantly in recent years. For example, the WTI spot price for oil declined from a high of $107.95 per barrel in June 2014 to a low of $26.19 per barrel in February 2016, and the NYMEX Henry Hub spot price for natural gas declined from a high of $8.15 per MMBtu in February 2014 to a low of $1.49 per MMBtu in March 2016. Likewise, NGLs have suffered significant recent declines in realized prices. The price of propane (Mont Belvieu) ranged from a high of $1.73 per gallon in February 2014 to a low of $0.30 per gallon in January 2016 and the price of ethane (Mont Belvieu) ranged from a high of $0.45 per gallon in January 2014 to a low of $0.13 per gallon in December 2015. Impairment expense for the years ended December 31, 2017, 2016, and 2015 was $1.1 million, zero, and $8.1 million, respectively. Lower commodity prices in the future could result in 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.

Unless we replace our reserves with new reserves and develops 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 acquires 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 the 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.

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

We have historically sold our production to a relatively small number of customers, as is customary in our business. For the year ended December 31, 2017 and 2016, two and three customers accounted for approximately 90% and 97%, respectively, of our total revenue. During such periods, no other purchaser accounted for 10% or more of our revenue. The loss of any one or all of our significant customers as a purchaser could materially and adversely affect our revenues in the short-term.

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, occupational health and safety aspects of our operations, or otherwise relating to the protection of the environment and natural resources. 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 the 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; or 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 may require us to perform 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; and plugging and abandonment responsibilities for wells which have ceased producing. 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 liabilities for costs required to remediate and restore sites where hazardous substances, hydrocarbons or solid wastes have been released into the environment. We may be required to remediate contaminated properties currently or formerly operated by us or our predecessors in interest 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. The trend has been for more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry, resulting in increased costs of doing business and consequently affecting profitability. For example, in June 2016, the EPA finalized a rule regarding criteria for aggregating multiple small surface sites into a single source for air-quality permitting purposes applicable to the oil and gas industry. This rule could cause small facilities, on an aggregate basis, to be deemed a major source, thereby triggering more stringent air permitting requirements. In addition, in October 2015, the EPA lowered the National Ambient Air Quality Standard ("NAAQS") for ozone from 75 to 70 parts per billion. In November 2017, the EPA published a list of areas that are in compliance with the new ozone standards and separately in December 2017 issued responses to state recommendations for designating non-attainment areas. States have the opportunity to submit new air quality monitoring to EPA prior to EPA finalizing any non-attainment designations, which EPA is expected to issue during the first half of 2018. 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. 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 the 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 exploration and 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 and air contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and drill pipe or casing failures or collapse;
- fire, explosions and ruptures of pipelines;
- personal injuries and death;
- natural disasters, which may include severe weather as possibly connected to climate change and seismic events as possibly connected to injection of produced water and flowback into disposal wells; 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;

- statutory or regulatory investigations and penalties; 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, statutory and regulatory penalties, 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 and data from other wells in the same area, or more fully explored prospects, will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, in commercial quantities. Further, drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, including:

- unexpected or adverse drilling conditions;
- title problems;
- elevated pressure or lost circulation in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental or contractual requirements; and
- increase 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 assets or 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 assets or business. The process of integrating acquired assets or businesses may involve unforeseen difficulties and may require a disproportionate amount of 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, Certificate of Designations for the Series B Preferred Stock and the Note Purchase Agreement impose, and future debt agreements may impose, among other things, limitations on our ability to enter into mergers or combination transactions. See "Restrictions in our Credit Agreement, Certificate of Designations for the Series B Preferred Stock and the Note Purchase Agreement limit, and our future debt agreements could limit, our ability to engage in certain activities." Such limitations may also restrict our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of assets or businesses.

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

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

- recoverable reserves;
- future oil and natural gas prices and their applicable differentials;
- geological risks;
- access to markets;
- 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. However, these reviews 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.

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

In order to bring equipment, supplies, water, personnel and produced products to and from certain of our properties, we and/or our contractors must obtain permissions or rights-of-way from other parties, including private property owners and governmental agencies. There is no guarantee that we or our contractors will be able to obtain or continue to obtain those permissions or rights or to obtain them at a reasonable cost. In addition, certain of our properties are subject to land use restrictions, including ordinances, which could limit the manner in which we conduct our business. Although none of our proposed drilling locations associated with proved undeveloped reserves as of December 31, 2017 are on properties currently subject to such land use restrictions, such restrictions may become effective in the future. All of the permissions, rights-of-way, and restrictions discussed above 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 incurred to comply with such restrictions may be significant in nature, and we may experience delays or curtailment in the pursuit of development activities and may 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.

We do not own any drilling rigs, nor do we own other equipment and supplies that are critical to our continuing ability to drill for and produce oil, gas, and NGLs. We are dependent on access to qualified and competent contractors for such equipment and supplies, as well as the personnel to engage in our drilling and production program. 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 has 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, has increased, as have the costs for those items. We may not be able to renew or obtain new drilling contracts for rigs whose contracts are expiring or are terminated or obtain drilling contracts for our uncontracted new builds. Any delay or inability to secure the personnel, including frac crews, equipment, power, services, resources and facilities access necessary for us to 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 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 prior or future commodity derivative activities.

Should we fail to comply with all applicable Federal Energy Regulatory Commission ("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, FERC has civil penalty authority under the Natural Gas Act of 1938 ("NGA") and the Natural Gas Policy Act of 1978 ("NGPA") to impose penalties of up to $1,238,271 per day for each violation for current violations 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's 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.

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 GHG emissions from certain large stationary sources that otherwise require such permits for non-GHG emissions. 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 June 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. However, in June 2017, the EPA published a proposed rule to stay certain portions of the June 2016 standards for two years and re-evaluate the entirety of the 2016 standards, but the EPA has not yet published a final rule and, as a result, the June 2016 rule remains in effect but future implementation of the 2016 standards is uncertain at this time. To the extent implemented, compliance with these rules would 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 would also likely require additional personnel time to support these activities or the engagement of third party contractors to assist with and verify compliance. New rules related to the reduction of methane and GHG emissions could result in increased compliance costs on our operations.

There have not been significant legislative proposals to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional programs and initiatives have been enacted or are being considered that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs, direct taxation of carbon emissions, or that promote the use of less carbon-intensive fuels. At the international level, the United States joined the international community at the 21st Conference of the Parties of the United Nations Framework Convention on Climate Change in Paris, France, which resulted in an agreement (the "Paris Agreement") that requires member countries to review and "represent a progression" in their intended nationally determined contributions, and set GHG emission reduction goals every five years beginning in 2020. The Paris Agreement entered into force in November 2016. Although this agreement does not create any binding obligations for nations to limit their GHG emissions, it does include pledges from the participating nations to voluntarily limit or reduce future emissions. In June 2017, President Trump stated that the United States would withdraw from the Paris Agreement, but may enter into a future international agreement related to GHGs on different terms. The Paris Agreement provides for a four-year exit process beginning when it took effect in November 2016, which would result in an effective exit date of November 2020. The United States' adherence to the exit process is uncertain and/or the terms on which the United States may reenter the Paris Agreement or a separately negotiated agreement are unclear at this time.

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. Substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce and lower the value of our reserves. Recently, activists concerned about the potential effects of climate change have directed their attention at sources of funding for fossil-fuel energy companies, which has resulted in certain financial institutions, funds and other sources of capital restricting or eliminating their investment in oil and natural gas activities. Ultimately, this could make it more difficult to secure funding for exploration and production activities. Notwithstanding potential risks related to climate change, the International Energy Agency estimates that global energy demand will continue to rise and will not peak until after 2040 and that oil and gas will continue to represent a substantial percentage of global energy use over that time. Finally, it should be noted that some scientists have concluded that 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, droughts, and other climatic events. Our operations are onshore and not located in coastal or flood-prone regions of the United States, but if any such effects were to occur, they have the potential to cause physical damage to our assets or affect the availability of water for our operations and thus could have a material adverse effect 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 and expect to continue that practice. Hydraulic fracturing is typically regulated by state oil and natural gas commissions, but 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 issued: final regulations under the federal Clean Air Act establishing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; and also finalized rules in June 2016 that prohibit the discharge of wastewater from hydraulic fracturing operations to publicly owned wastewater treatment plants.

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. As described elsewhere in this Annual Report on Form 10-K, these risks are regulated under various state, federal, and local laws. The EPA's study report did not find a direct link between the action of hydraulically fracturing the well itself and contamination of groundwater resources. The study report does not, therefore, appear to provide a reasonable basis to expect Congress to repeal the exemption for hydraulic fracturing under the federal Safe Drinking Water Act at the federal level.

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 includes 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. 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, including saltwater, 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 hydraulic fracturing related activities and the increased occurrence of seismic activity, and regulatory agencies at all levels are continuing to study the possible linkage between oil and gas activity and induced seismicity. In 2015, the United States Geological Survey identified eight states, including Texas, with areas of increased rates of induced seismicity that could be attributed to fluid injection or oil and gas extraction. In addition, a number of lawsuits have been filed in other states, for example recent lawsuits 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 on 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 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 for a disposal well permit fails to demonstrate that the saltwater or other fluids are confined to the disposal zone or if scientific data indicates that 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. The Oklahoma Corporation Commission also released well completion seismicity guidelines in December 2016 for operators in the SCOOP and STACK that call for hydraulic fracturing operations to be suspended following earthquakes of certain magnitudes in the vicinity. In addition, in February 2017, the Oklahoma Corporation Commission's Oil and Gas Conservation Division issued an order limiting future increases in the volume of oil and natural gas wastewater injected into the ground in an effort to reduce the number of earthquakes in the state. It is possible that similar measures could be implemented in the areas where we operate.

We dispose of large volumes of produced water, including saltwater, gathered from our drilling and production operations using disposal wells pursuant to permits issued by governmental authorities overseeing such disposal activities and pursuant to permissions granted by the owners of properties where the disposal wells are located. While these permits are issued in accordance with existing laws and regulations, these legal requirements are subject to change, as are the permissions granted by property owners. Any changes 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 or property owners regarding such gathering or disposal activities. The adoption and implementation of any new laws or regulations or changes that restrict our expected ability to use hydraulic fracturing or dispose of produced water gathered from our drilling and production activities, either by limiting disposal volumes, 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 our 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 such senior management or technical personnel could have a material adverse effect on our business, financial condition and results of operations.

Our business is difficult to evaluate because it may be susceptible to the potential difficulties associated with rapid growth and expansion.

Our assets have grown rapidly over the last several years. We believe 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 contained in this Annual Report on Form 10-K is not necessarily indicative of the results that may be realized in the future.

Failure to maintain effective internal controls over financial reporting could have a material adverse effect on our business, operating results and stock price.

Management concluded that the Company had a material weakness as of December 31, 2017 due to significant deficiencies in the following areas:

- asset retirement obligations estimates;
- timely reconciliation and review of accounts;
- determination of accrued liabilities;
- identification and documentation of related party transactions; and
- depreciation, depletion and amortization calculations.

A material weakness also existed at December 31, 2017 related to the timely identification and analysis of the appropriate accounting treatment of complex transactions. This relates to the beneficial conversion feature matter requiring restatement, filed on November 3, 2017, of the Company's financial statements for the period ended June 30, 2017, identification of an embedded derivative related to the change of control provision in our Series B Preferred Stock, accounting for noncontrolling interest and income taxes. As a result of the error and the related restatement of the Company's financial statements, and as a result of the material weaknesses identified, our CEO and CFO have concluded that our internal controls over financial reporting were not effective as of December 31, 2017.

Our disposition activities may be subject to factors beyond our control, and in certain cases we may retain unforeseen liabilities for certain matters.

We have regularly sold non-core assets in order to increase capital resources available for other core assets and to create organizational and operational efficiencies. We have also occasionally sold interests in core assets for the purpose of accelerating the development and increasing efficiencies in such core assets. Various factors could materially affect our ability to dispose of such assets in the future, including the approvals of governmental agencies or third parties and the availability of purchasers willing to acquire the assets with terms we deem acceptable.

Sellers often retain certain liabilities or agree to indemnify buyers for certain matters related to the sold assets. The magnitude of any such retained liability or of the indemnification obligation is difficult to quantify at the time of the transaction and ultimately could be material. Also, as is typical in divestiture transactions, third parties may be unwilling to release us from guarantees or other credit support provided prior to the sale of the divested assets. As a result, after a divestiture, we may remain secondarily liable for the obligations guaranteed or supported to the extent that the buyer of the assets fails to perform these obligations.

The standardized measure of our estimated proved reserves and our PV-10 are not necessarily the same as the current market value of our estimated proved oil, natural gas, and natural gas liquids reserves.

The present value of future net cash flow from our proved reserves, or standardized measure, and our related PV-10 calculation, may not represent the current market value of our estimated proved oil reserves. In accordance with SEC requirements, we base the estimated discounted future net cash flow from our estimated proved reserves on the 12-month average oil index prices, calculated as the unweighted arithmetic average for the first-day-of-the-month price for each month and costs in effect as of the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than current estimates. In addition, the 10% discount factor we use when calculating discounted future net cash flow for reporting requirements in compliance with the Financial Accounting Standard Board Codification 932, "Extractive Activities-Oil and Gas," may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general.

Our ability to use net operating loss carryforwards to offset future taxable income for U.S. federal income tax purposes is subject to limitation.

As of December 31, 2017, we have approximately $21 million of U.S. federal operating loss carryforwards ("NOLs"), which will begin to expire in 2035. Utilization of these NOLs depends on many factors, including our future income, which cannot be assured. In addition, Section 382 of the Internal Revenue Code of 1986, as amended ("Section 382"), generally imposes an annual limitation on the amount of NOLs that may be used to offset taxable income when a corporation that has undergone an "ownership change" (as determined under Section 382) An ownership change generally occurs if one or more shareholders (or group of shareholders) who are each deemed to own at least 5% of our stock change their ownership by more than 50 percentage points over their lowest ownership percentage during a rolling three-year period.

In the event that an ownership change has occurred, or were to occur, utilization of our NOLs in existence at the time of the ownership change would be subject to an annual limitation under Section 382, determined by multiplying the value of our stock at the time of the ownership change by the applicable long-term tax-exempt rate as defined in Section 382, subject to certain adjustments. Any unused annual limitation may be carried over to later years until they expire.

We believe we experienced an ownership change as a result of the Transaction on April 27, 2017, and our NOLs at the time of the Transaction are subject to limitation under Section 382 of the Code, which may cause U.S. federal income taxes to be paid earlier than otherwise would be paid if such limitation were not in effect and could cause such NOLs to expire unused, in each case reducing or eliminating the benefit of such NOLs. To the extent we are not able to offset our future income with our NOLs, this would adversely affect our operating results and cash flows if we attain profitability. Similar rules and limitations may apply for state income tax purposes.

We depend on computer and telecommunications systems and failures in our systems or cyber security attacks could significantly disrupt our business operations.

We have entered into agreements with third parties for hardware, software, telecommunications and other information technology services in connection with our business. In addition, we have developed proprietary software systems, management techniques and other information technologies incorporating software licensed from third parties. It is possible we could incur interruptions from cyber security attacks, computer viruses or malware. We believe that we have positive relations with our related vendors and maintain adequate anti-virus and malware software and controls; however, any interruptions to our arrangements with third parties to our computing and communications infrastructure or our information systems could significantly disrupt our business operations.

Our derivative transactions expose us to counterparty credit risk.

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

Hedging transactions may limit our potential gains and increase our potential losses.

In order to manage our exposure to price risks in the marketing of our oil, natural gas, and natural gas liquids production, we have entered into oil, natural gas, and natural gas liquids price hedging arrangements with respect to a portion of our anticipated production and we may enter into additional hedging transactions in the future. While intended to reduce the effects of volatile commodity prices, such transactions may limit our potential gains and increase our potential losses if commodity prices were to rise substantially over the price established by the hedge. In addition, such transactions may expose us to the risk of loss in certain circumstances, including instances in which:

- our production is less than expected;
- there is a widening of price differentials between delivery points for our production; or
- the counterparties to our hedging agreements fail to perform under the contracts.

The adoption of derivatives legislation by Congress could have an adverse impact on our ability to use derivative instruments to reduce the effects of commodity prices, interest rates and other risks associated with our business.

Historically, we have entered into a number of commodity derivative contracts in order to hedge a portion of our oil and natural gas production. On July 21, 2010, then President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, which requires the SEC and the Commodity Futures Trading Commission (or CFTC), along with other federal agencies, to promulgate regulations implementing the new legislation.

The CFTC has finalized other regulations implementing the Dodd-Frank Act's provisions regarding trade reporting, margin, clearing, and trade execution; however, some regulations remain to be finalized and it is not possible at this time to predict when the CFTC will adopt final rules. For example, the CFTC has re-proposed regulations setting position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions are expected to be made exempt from these limits. Also, it is possible that under recently adopted margin rules, some registered swap dealers may require us to post initial and variation margins in connection with certain swaps not subject to central clearing.

The Dodd-Frank Act and any additional implementing regulations could significantly increase the cost of some commodity derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of some commodity derivative contracts, limit our ability to trade some derivatives to hedge risks, reduce the availability of some derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing commodity derivative contracts. If we reduce our use of derivatives as a consequence, 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. Increased volatility may make us less attractive to certain types of investors. Finally, the Dodd-Frank Act was 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. If the implementing regulations result in lower commodity prices, our revenues could be adversely affected. Any of these consequences could adversely affect our business, financial condition and results of operations.

Future regulations relating to and interpretations of recently enacted U.S. federal income tax legislation may vary from our current interpretation of such legislation.

The U.S. federal income tax legislation recently enacted in Public Law No. 115-97, commonly referred to as the Tax Cuts and Jobs Act (the "Tax Act"), is highly complex and subject to interpretation. The presentation of our financial condition and results of operations is based upon our current interpretation of the provisions contained in the Tax Act. In the future, the Treasury Department and the Internal Revenue Service are expected to release regulations relating to and interpretive guidance of the legislation contained in the Tax Act. Any significant variance of our current interpretation of such legislation from any future regulations or interpretive guidance could result in a change to the presentation of our financial condition and results of operations and could negatively affect our business.

Changes to state tax laws in response to recently enacted U.S. federal tax legislation.

Currently, many states conform their calculation of corporate taxable income to the calculation of corporate taxable income at the U.S. federal level. Due to recently enacted changes to U.S. federal income tax laws, certain states may change or modify the calculation of corporate taxable income at the state level. Any resulting increase in costs due to such changes could have an adverse effect on our financial position, results of operations and cash flows.

Risks Related to Our Indebtedness

We may incur substantial additional debt, which could decrease our ability to maintain operations or service existing debt obligations.

Subject to the restrictions in our Credit Agreement, Certificate of Designations for the Series B Preferred Stock and the Note Purchase Agreement (as defined below), we may incur substantial additional debt in the future. We may also consider investments in joint ventures or acquisitions that may increase our indebtedness. Adding new debt to then existing debt levels could intensify the operational risks that we now face.

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 Agreement and Second Lien Notes or line of credit, 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 current and future 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 our 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 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. Our Credit Agreement, Certificate of Designations for the Series B Preferred Stock and the Note Purchase Agreement restrict, among other things, our ability to dispose of assets and our use of the proceeds from such disposition. See “Restrictions in our Credit Agreement, Certificate of Designations for the Series B."

Preferred Stock and the Note Purchase Agreement limit, and our future debt agreements could limit, our ability to engage in certain activities.” 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 Credit Agreement, Certificate of Designations for the Series B Preferred Stock and the Note Purchase Agreement limit, and our future debt agreements could limit, our ability to engage in certain activities.

Our Credit Agreement, Certificate of Designations for the Series B Preferred Stock and the Note Purchase Agreement contain, and our future debt agreements may contain, a number of significant covenants, including restrictive covenants that limit our ability to, among other things:

- incur additional indebtedness;
- be liable in respect of any third-party guaranty;
- incur liens;
- make loans to others;
- make investments;
- pay dividends or make distributions to third parties;
- liquidate, merge or consolidate with another entity;
- enter into commodity hedges exceeding a specified percentage of our expected production;
- enter into interest rate hedges exceeding a specified percentage of our outstanding indebtedness;
- sell properties or assets;
- issue additional shares of capital stock; and
- engage in certain other transactions without the prior consent of the holders of the Second Lien Notes, the Series B Preferred Stock and/or PNC Bank, National Association and the lenders under the Credit Agreement.

In addition, our Credit Agreement requires us to maintain the following financial ratios: (1) a working capital ratio, which is the ratio of consolidated current assets (including unused commitments under the Credit Agreement, but excluding non-cash assets) to consolidated current liabilities (excluding non-cash obligations, reclamation obligations to the extent classified as current liabilities and current maturities under the Credit Agreement), of not less than 1.0 to 1.0, and (2) a leverage ratio, which is the ratio of the sum of all of our Total Funded Debt to EBITDAX (as such terms are defined in the Credit Agreement) for the four fiscal quarters then ended, of not greater than 4.00 to 1.00. Failure to do so could result in mandatory or full repayment of the indebtedness. The senior secured revolving credit facility also does not permit us to borrow funds if at the time of such borrowing, we are not in pro forma compliance with the financial covenants.

A breach of any covenant in our Credit Agreement likely would result in a default under the Credit 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 may 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. If an event of default occurs under the Credit Agreement, PNC Bank, National Association will have the right to proceed against the pledged capital stock and take control of substantially all of our material operating subsidiaries that are guarantors' assets.

If we fail to pay dividends on the Series B Preferred Stock in any fiscal quarter, the dividend rate will increase from 10% to 12% per annum on the $1,000 liquidation preference per share of Series B Preferred Stock until such dividends are paid in full. In addition, if the Company fails to pay dividends for three out of four consecutive fiscal quarters or for six quarters (whether or not consecutive), then a representative appointed by the holders of a majority of the outstanding shares of Series B Preferred Stock shall have the right to appoint one director to our board of directors, and we shall be required to seek the approval of such representative for certain corporate actions, in each case, until three months following the date on which such dividends are paid in full.

The restrictions in our Credit Agreement, Certificate of Designations for the Series B Preferred Stock and the Note Purchase Agreement 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, Certificate of Designations for the Series B Preferred Stock and the Note Purchase Agreement impose on us.

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

Our Credit Agreement limits the amounts we can borrow up to a borrowing base amount, which the lenders, in their sole discretion, determine at certain periods throughout the year. The borrowing base depends on, among other things, projected revenues from, and asset values of, the oil and natural gas properties securing our loan. If we do not furnish the information required for the redetermination by the specified date, the lender may nonetheless redetermine the borrowing base in their sole discretion until the relevant information is received.

In the future, we may not be able to access adequate funding under our Credit Agreement (or a replacement facility) as a result of a decrease in our 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 respective 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.

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. Our Credit Agreement is subject to similar or greater interest rate expenses. Recent and continuing disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance 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 planned growth and operating results.

Risks Related to Our Capital Structure

We are a holding company. Our sole material asset is our equity interest in Rosehill Operating and we are accordingly dependent upon distributions from Rosehill Operating to pay taxes, make payments under the Tax Receivable Agreement, cover our corporate and other overhead expenses and make payments with respect to our Series A Preferred Stock and Series B Preferred Stock.

We are a holding company and have no material assets other than our equity interest in Rosehill Operating. We have no independent means of generating revenue. To the extent Rosehill Operating has available cash, we intend to cause Rosehill Operating to make (i) generally pro rata distributions to its unitholders, including us, in an amount at least sufficient to allow us to pay dividends with respect to the Series A Preferred Stock and the Series B Preferred Stock, pay our taxes and to make payments under the Tax Receivable Agreement with Tema and (ii) non-pro rata payments to us to reimburse us for our corporate and other overhead expenses. To the extent that we need funds and Rosehill Operating or its subsidiaries are restricted from making such distributions or payments under applicable law or regulation or under the terms of any financing arrangements, or are otherwise unable to provide such funds, our liquidity and financial condition could be materially adversely affected.

The market price of the Class A Common Stock may decline.

Fluctuations in the price of the Class A Common Stock could contribute to the loss of all or part of your investment. Prior to the closing of the Transaction, trading in our Class A Common Stock and Public Warrants had been limited. The trading price of the Class A Common Stock could be volatile and subject to wide fluctuations in response to various factors, some of which are beyond our control. Any of the factors listed below could have a material adverse effect on your investment and the Class A Common Stock may trade at prices significantly below the price you paid for them. In such circumstances, the trading price of the Class A Common Stock may not recover and may experience a further decline.

Factors affecting the trading price of the Class A Common Stock may include:

- actual or anticipated fluctuations in our quarterly financial results or the quarterly financial results of companies perceived to be similar to us;
- changes in the market's expectations about our operating results;
- success of competitors;
- our operating results failing to meet the expectation of securities analysts or investors in a particular period;
- changes in financial estimates and recommendations by securities analysts concerning us or our markets in general;
- operating and stock price performance of other companies that investors deem comparable to us;
- our ability to market new and enhanced products on a timely basis;
- changes in laws and regulations affecting our business;
- commencement of, or involvement in, litigation involving us;
- changes in our capital structure, such as future issuances of securities or the incurrence of additional debt;
- the volume of securities available for public sale;
- any major change in our board or management;
- sales of substantial amounts of our securities by our directors, executive officers or significant stockholders or the perception that such sales could occur; and
- general economic and political conditions such as recession; interest rate, fuel price, and international currency fluctuations; and acts of war or terrorism.

Many of the factors listed above are beyond our control. In addition, broad market and industry factors may materially harm the market price of the Class A Common Stock irrespective of our operating performance. The stock market in general, and NASDAQ have experienced price and volume fluctuations that have often been unrelated or disproportionate to the operating performance of the particular companies affected. The trading prices and valuations of our Class A Common Stock and Public Warrants, which trade on The NASDAQ Capital Market, may not be predictable. A loss of investor confidence in the market for retail stocks or the stocks of other companies which investors perceive to be similar to us could depress the price of the Class A Common Stock regardless of our business, prospects, financial conditions or results of operations. A decline in the market price of the Class A Common Stock also could adversely affect our ability to issue additional securities and our ability to obtain additional financing in the future.

If securities or industry analysts do not publish or cease publishing research or reports about us, our business, or our market, or if they change their recommendations regarding the Class A Common Stock adversely, the price and trading volume of the Class A Common Stock could decline.

The trading market for the Class A Common Stock relies in part on the research and reports that industry or financial analysts publish about us or our business. We do not control these analysts and there can be no assurance that any will cover us in the future. Furthermore, if one or more analysts do cover us and downgrade or provide negative outlook on our stock or our industry, or the stock of any of our competitors, or publishes inaccurate or unfavorable research about our business, the price of the Class A Common Stock could decline. If one or more of these analysts commence and subsequently cease coverage of our business or fail to publish reports on us regularly, we could lose visibility in the market, which in turn could cause our stock price or trading volume to decline.

Tema and KLR Energy Sponsor, LLC ("KLR Sponsor") own a significant percentage of our outstanding voting common stock.

Tema and KLR Sponsor currently beneficially own approximately 86.7% of our voting common stock and, upon the conversion of our Series A Preferred Stock, will beneficially own approximately 74.0% of our voting common stock. As long as Tema and KLR Sponsor own or control a significant percentage of outstanding voting power, they will continue to have the ability to strongly influence all corporate actions requiring stockholder approval, including the election and removal of directors and the size of our board of directors, any amendment of our charter or bylaws, or the approval of any merger or other significant corporate transaction, including a sale of substantially all of our assets.

The interests of Tema and KLR Sponsor may not align with the interests of our other stockholders. Tema and KLR Sponsor may acquire and hold interests in businesses that compete directly or indirectly with us. Tema and KLR Sponsor may also pursue acquisition opportunities that may be complementary to our business, and, as a result, those acquisition opportunities may not be available to us. In addition, our second amended and restated certificate of incorporation, amended and restated bylaws and the Shareholders' and Registration Rights Agreement, dated as of December 20, 2016, by and among the Company, Tema, KLR Sponsor, Anchorage Illiquid Opportunities V, L.P. and AIO V AIV 3 Holdings, L.P. (the "SHRRA"), provide that, subject to certain limitations, we renounce any interest or expectancy in the business opportunities of our officers and directors and their respective affiliates and each such party shall not have any obligation to offer us those opportunities unless presented to one of our directors or officers in his or her capacity as a director or officer.

We are currently a "controlled company" within the meaning of the NASDAQ Listing Rules, but may not retain that status in the event that we conduct equity offerings in the future. However, during the phase-in period we may continue to rely on exemptions from certain corporate governance requirements that provide protection to stockholders of other companies.

Because Tema and KLR Sponsor control a majority of the combined voting power of all classes of our outstanding voting stock, we have been a "controlled company" under NASDAQ corporate governance listing standards. Under the NASDAQ 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 NASDAQ 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; and

- the compensation committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities.

In the event that we conduct equity offerings in the future, Tema and KLR Sponsor may cease to control a majority of the combined voting power of all classes of our outstanding voting stock. Accordingly, we may no longer be a "controlled company" within the meaning of the rules of NASDAQ. Under NASDAQ rules, a company that ceases to be a controlled company must comply with the independent board committee requirements as they relate to the nominating and corporate governance and compensation committees on the following phase-in schedule: (1) one independent committee member at the time it ceases to be a controlled company, (2) a majority of independent committee members within 90 days of the date it ceases to be a controlled company and (3) all independent committee members within one year of the date it ceases to be a controlled company. Additionally, NASDAQ rules provide a 12-month phase-in period from the date a company ceases to be a controlled company to comply with the majority independent board requirement. During these phase-in periods, our stockholders will not have the same protections afforded to stockholders of companies of which the majority of directors are independent. Additionally, if, within the phase-in periods, we are not able to recruit additional directors who would qualify as independent, or otherwise comply with NASDAQ rules, we may be subject to enforcement actions by NASDAQ. Furthermore, a change in our board of directors and committee membership may result in a change in corporate strategy and operation philosophies, and may result in deviations from our current growth strategy.

The pro forma per share data included in this Annual Report on Form 10-K excludes the transaction costs attributable to the Transaction and may not be indicative of what our actual financial position or results of operations would have been had the Transaction not occurred.

We incurred non-recurring transaction costs that were directly attributable to the Transaction of $2.6 million and $2.8 million for the years ended December 31, 2017 and 2016, respectively. The pro forma per share data included in this Annual Report on Form 10-K was calculated excluding transactions costs attributable to the Transaction and is presented for illustrative purposes only. The pro forma per share data is not necessarily indicative of what our actual financial position or results of operations would have been had the Transaction not been completed on the dates indicated. See "Selected Financial Data."

Future sales of our common stock 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 Class A Common Stock or securities convertible into Class A Common Stock in subsequent public or private offerings. On December 31, 2017, 6,222,299 shares of our Class A Common Stock were issued and outstanding.

Downward pressure on the market price of our Class A Common Stock that likely will result from sales of our Class A Common Stock issued in connection with the exercise of warrants for shares of Class A Common Stock or the conversion of the Class B Common Stock or Series A Preferred Stock could encourage short sales of our Class A Common Stock by market participants. Generally, short selling means selling a security, contract or commodity not owned by the seller. The seller is committed to eventually purchase the financial instrument previously sold. Short sales are used to capitalize on an expected decline in the security's price. Such sales of our Class A Common Stock could have a tendency to depress the price of the stock, which could increase the potential for short sales.

We cannot predict the size of future issuances of our Class A Common Stock or securities convertible into Class A Common Stock or the effect, if any, that future issuances and sales of shares of our Class A Common Stock will have on the market price of our Class A Common Stock. Sales of substantial amounts of our Class A 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 Class A Common Stock are equity interests and are therefore subordinated to our indebtedness.

In the event of our liquidation, dissolution or winding up, the Class A Common Stock would rank below our Series A Preferred Stock and Series B Preferred Stock and all secured debt claims against us. As a result, holders of the Class A Common Stock will not be entitled to receive any payment or other distribution of assets upon our liquidation, dissolution or winding up until after all of our obligations to our secured debt holders and to holders of our Series A Preferred Stock and Series B Preferred Stock have been satisfied.

The Series A Preferred Stock and the Series B Preferred Stock rank junior to all of our indebtedness and other liabilities.

In the event of our bankruptcy, liquidation, reorganization or other winding-up, our assets will be available to pay obligations on the Series A Preferred Stock and the Series B Preferred Stock only after all of our indebtedness and other liabilities have been paid. In addition, we are a holding company and the Series A Preferred Stock and the Series B Preferred Stock will effectively rank junior to all existing and future indebtedness and other liabilities (including trade payables) of our subsidiaries and any capital stock of our subsidiaries not held by us. The rights of holders of the Series A Preferred Stock and the Series B Preferred Stock to participate in the distribution of assets of our subsidiaries will rank junior to the prior claims of that subsidiary's creditors and any other equity holders. Consequently, if we are forced to liquidate our assets to pay our creditors, we may not have sufficient assets remaining to pay amounts due on any or all of the Series A Preferred Stock and the Series B Preferred Stock then outstanding. We and our subsidiaries may incur substantial amounts of additional debt and other obligations that will rank senior to the Series A Preferred Stock and the Series B Preferred Stock.

We are not obligated to pay dividends on the Series A Preferred Stock and the Series B Preferred Stock if prohibited by law and will not be able to pay cash dividends if we have insufficient cash to do so.

Under Delaware law, dividends on capital stock may only be paid from "surplus" or, if there is no "surplus," from the corporation's net profits for the then-current or the preceding fiscal year. Unless we operate profitably, our ability to pay dividends on the Series A Preferred Stock and the Series B Preferred Stock would require the availability of adequate "surplus," which is defined as the excess, if any, of our net assets (total assets less total liabilities) over our capital.

Further, even if adequate surplus is available to pay dividends on the Series A Preferred Stock and the Series B Preferred Stock, we may not have sufficient cash to pay cash dividends on the Series A Preferred Stock and the Series B Preferred Stock. We may elect to pay dividends on the Series A Preferred Stock and the Series B Preferred Stock in shares of additional Series A Preferred Stock or Series B Preferred Stock, as applicable; however, our ability to pay dividends in shares of our Series A Preferred Stock and Series B Preferred Stock may be limited by the number of shares of Series A Preferred Stock and Series B Preferred Stock we are authorized to issue under our second amended and restated certificate of incorporation (the "certificate of incorporation"). In the case of the Series B Preferred Stock, with respect to dividends declared for any quarter ending on or prior to January 15, 2019, the Company may elect to pay as dividends additional shares of Series B Preferred Stock in kind in an amount up to 40% of that which would have been payable had the dividends been fully paid in cash. As of December 31, 2017, we had 97,698 shares of Series A Preferred Stock outstanding and 150,626 shares of Series B Preferred Stock outstanding out of 1,000,000 authorized shares of preferred stock, 150,000 of which are designated as Series A Preferred Stock and 210,000 shares are designated as Series B Preferred Stock.

The terms of our financing agreements may limit our ability to pay dividends on the Series A Preferred Stock and the Series B Preferred Stock.

Financing agreements, whether ours or those of our subsidiaries and whether in place now or in the future, may contain restrictions on our ability to pay cash dividends on our capital stock, including the Series A Preferred Stock and the Series B Preferred Stock. These limitations may cause us to be unable to pay cash dividends on the Series A Preferred Stock and the Series B Preferred Stock. For example, the Credit Agreement will restrict our ability to pay cash dividends unless certain criteria are met. Since we are not obligated to declare or pay cash dividends, we do not intend to do so to the extent we are restricted by any of our financing agreements.

The Series A Preferred Stock and the Series B Preferred Stock do not have an established trading market, which may negatively affect their market value and the ability to transfer or sell such shares.

The Series A Preferred Stock and the Series B Preferred Stock do not have an established trading market. Since the Series A Preferred Stock and the Series B Preferred Stock have no stated maturity date, investors seeking liquidity will be limited to selling their shares in the secondary market or, in the case of holders of Series A Preferred Stock, converting their shares and selling in the secondary market. We do not intend to list the Series A Preferred Stock and the Series B Preferred Stock on any securities exchange. We cannot make any assurances that an active trading market in the Series A Preferred Stock and the Series B Preferred Stock will develop or, even if it develops, we cannot assure that it will last. In either case, the trading price of the Series A Preferred Stock and the Series B Preferred Stock could be adversely affected and the ability of holders of our Series A Preferred Stock and Series B Preferred Stock to transfer their shares will be limited. We are not aware of any entity making a market in the shares of our Series A Preferred Stock or Series B Preferred Stock which we anticipate may further limit liquidity.

Upon conversion of the Series A Preferred Stock, holders may receive less valuable consideration than expected because the value of our Class A Common Stock may decline after such holders exercise their conversion right but before we settle our conversion obligation.

Under the Series A Preferred Stock, a converting holder will be exposed to fluctuations in the value of our Class A Common Stock during the period from the date such holder surrenders shares of Series A Preferred Stock for conversion until the date we settle our conversion obligation. Upon conversion, we will be required to deliver the shares of our Class A Common Stock, together with a cash payment for any fractional share, on the third business day following the relevant conversion date. Accordingly, if the price of our Class A Common Stock decreases during this period, the value of the shares of Class A Common Stock that holders of Series A Preferred Stock receive will be adversely affected and would be less than the conversion value of the Series A Preferred Stock on the conversion date.

The conversion rate of the Series A Preferred Stock may not be adjusted for all dilutive events.

The number of shares of our Class A Common Stock that holders of our Series A Preferred Stock are entitled to receive upon conversion of the Series A Preferred Stock is subject to adjustment for certain specified events, including, but not limited to, the issuance of certain stock dividends on our Class A Common Stock, the issuance of certain rights or warrants, subdivisions, combinations, distributions of capital stock, indebtedness, or assets, cash dividends and certain issuer tender or exchange offers, as set forth in the Certificate of Designations for the Series A Preferred Stock. However, the conversion rate may not be adjusted for other events, such as the exercise of stock options held by our employees or offerings of our Class A Common Stock or securities convertible into Class A Common Stock (other than those set forth in the Certificate of Designations for the Series A Preferred Stock) for cash or in connection with acquisitions, which may adversely affect the market price of our Class A Common Stock. Further, if any of these other events adversely affects the market price of our Class A Common Stock, we expect it to also adversely affect the market price of our Series A Preferred Stock. In addition, the terms of our Series A Preferred Stock do not restrict our ability to offer Class A Common Stock or securities convertible into Class A Common Stock in the future or to engage in other transactions that could dilute our Class A Common Stock. We have no obligation to consider the interests of the holders of our Series A Preferred Stock in engaging in any such offering or transaction. If we issue additional shares of Class A Common Stock, those issuances may materially and adversely affect the market price of our Class A Common Stock and, in turn, those issuances may adversely affect the trading price of the Series A Preferred Stock.

The additional shares of our Class A Common Stock deliverable for shares of Series A Preferred Stock converted in connection with a fundamental change may not adequately compensate holders of our Series A Preferred Stock.

If a "fundamental change" (as defined in the Certificate of Designations for the Series A Preferred Stock) occurs, we will under certain circumstances increase the conversion rate by a number of additional shares of our Class A Common Stock for shares of Series A Preferred Stock converted in connection with such fundamental change as described in the Certificate of Designations. While this feature is designed to, among other things, compensate holders of our Series A Preferred Stock for lost option time value of their shares of Series A Preferred Stock as a result of the fundamental change, it may not adequately compensate them for their loss as a result of such transaction.

In addition, holders of the Series A Preferred Stock will have no additional rights upon a fundamental change, and will have no right not to convert the Series A Preferred Stock into shares of our Class A Common Stock. Any shares of Class A Common Stock such holders receive upon a fundamental change may be worth less than the liquidation preference per share of Series A Preferred Stock.

Our obligation to satisfy the additional shares requirement could be considered a penalty, in which case the enforceability thereof would be subject to general principles of reasonableness and equitable remedies.

In some limited circumstances, we may not have reserved a sufficient number of shares of our Class A Common Stock to issue the full amount of shares of Class A Common Stock issuable upon conversion following a fundamental change.

Some significant restructuring transactions may not constitute a fundamental change but may nevertheless result in holders of the Series A Preferred Stock being adversely affected.

Upon the occurrence of a "fundamental change" (as defined in the Certificate of Designations for the Series A Preferred Stock), there may be an increase in the conversion rate as described in the Certificate of Designations. However, these provisions will not afford protection to holders of Series A Preferred Stock in the event of other transactions that could adversely affect the value of the Series A Preferred Stock. For example, transactions such as leveraged recapitalizations, refinancings, restructurings, or acquisitions initiated by us may not constitute a fundamental change. In the event of any such transaction, holders would not have the protection afforded by the provisions applicable to a fundamental change even though each of these transactions could increase the amount of our indebtedness, or otherwise adversely affect our capital structure or any credit ratings, thereby adversely affecting the holders of Series A Preferred Stock.

Upon a conversion in connection with a fundamental change, holders of our Series A Preferred Stock may receive consideration worth less than the $1,000 liquidation preference per share of Series A Preferred Stock, plus any accumulated and unpaid dividends thereon.

If a "fundamental change" (as defined in the Certificate of Designations for the Series A Preferred Stock) occurs, and regardless of the price paid (or deemed paid) per share of our Class A Common Stock in such fundamental change, then the conversion rate may be adjusted to increase the number of the shares of our Class A Common Stock deliverable upon conversion of each share of Series A Preferred Stock to the $1,000 liquidation preference per share of Series A Preferred Stock, *plus* any accumulated and unpaid dividends thereon. However, under certain circumstances, holders may receive a number of shares of Class A Common Stock worth less than the $1,000 liquidation preference per share of Series A Preferred Stock, *plus* any accumulated and unpaid dividends thereon. Holders of our Series A Preferred Stock have no claim against us for the difference between the value of the consideration they receive upon a conversion in connection with a fundamental change and the $1,000 liquidation preference per share of Series A Preferred Stock, *plus* any accumulated and unpaid dividends thereon.

We may issue additional series of preferred stock that rank equally to the Series A Preferred Stock and the Series B Preferred Stock as to dividend payments and liquidation preference.

Neither our certificate of incorporation, the Certificate of Designations for the Series A Preferred Stock nor the Certificate of Designations for the Series B Preferred Stock prohibits us from issuing additional series of preferred stock that would rank equally to the Series A Preferred Stock and the Series B Preferred Stock as to dividend payments and liquidation preference. Our certificate of incorporation, the Certificate of Designations for the Series A Preferred Stock and the Certificate of Designations for the Series B Preferred Stock provide that we have the authority to issue up to 1,000,000 shares of preferred stock, including up to 150,000 shares of Series A Preferred Stock and 210,000 shares of Series B Preferred Stock. The issuances of other series of preferred stock could have the effect of reducing the amounts available to the Series A Preferred Stock and the Series B Preferred Stock in the event of our liquidation, winding-up or dissolution. It may also reduce cash dividend payments on the Series A Preferred Stock and the Series B Preferred Stock if we do not have sufficient funds to pay dividends on all outstanding Series A Preferred Stock and Series B Preferred Stock and parity preferred stock.

Holders of our Series A Preferred Stock have no rights with respect to the shares of our Class A Common Stock underlying the Series A Preferred Stock until they convert their Series A Preferred Stock, but they may be adversely affected by certain changes made with respect to our Class A Common Stock.

Holders of our Series A Preferred Stock will have no rights with respect to the shares of our Class A Common Stock underlying their Series A Preferred Stock, including voting rights, rights to respond to Class A Common Stock tender offers, if any, and rights to receive dividends or other distributions on our Class A Common Stock, if any (in each case, other than through a conversion rate adjustment), prior to the conversion date with respect to a conversion of such holder's Series A Preferred Stock, but the investment in our Series A Preferred Stock may be negatively affected by these events. Upon conversion, holders of our Series A Preferred Stock will be entitled to exercise the rights of a holder of Class A Common Stock only as to matters for which the relevant record date occurs on or after the conversion date. For example, in the event that an amendment is proposed to our certificate of incorporation or bylaws requiring stockholder approval and the record date for determining the stockholders of record entitled to vote on the amendment occurs prior to the conversion date, holders of our Series A Preferred Stock will not be entitled to vote on the amendment, although they will nevertheless be subject to any changes in the powers, preferences or special rights of our Class A Common Stock.

Holders of our Series A Preferred Stock and Series B Preferred Stock will have no voting rights except under limited circumstances.

Except with respect to certain material and adverse changes to the Series A Preferred Stock and the Series B Preferred Stock as described in the Certificate of Designations for the Series A Preferred Stock and the Certificate of Designations for the Series B Preferred Stock, respectively, holders of our preferred stock do not have voting rights and have no right to vote for any members of our board of directors, except as may be required by Delaware law.

We may not have sufficient earnings and profits in order for distributions on the Series A Preferred Stock and the Series B Preferred Stock to be treated as dividends for U.S. federal income tax purposes.

Distributions payable by us on the Series A Preferred Stock and the Series B Preferred Stock may exceed our current and accumulated earnings and profits, as calculated for U.S. federal income tax purposes. To the extent that the amount of a distribution with respect to our Series A Preferred Stock or Series B Preferred Stock exceeds our current and accumulated earnings and profits, such distribution will be treated for U.S. federal income tax purposes as a return of capital and first be applied against and reduce the beneficial owner’s adjusted tax basis in the Series A Preferred Stock or the Series B Preferred Stock, but not below zero. Any excess over such adjusted tax basis will be treated as capital gain. Such treatment will generally be unfavorable for corporate beneficial owners and may also be unfavorable to certain other beneficial owners.

Holders of our Series A Preferred Stock may be subject to tax if we make or fail to make certain adjustments to the conversion rate of the Series A Preferred Stock even though they do not receive a corresponding cash distribution.

The conversion rate of the Series A Preferred Stock is subject to adjustment in certain circumstances, including the payment of cash dividends. If the conversion rate is adjusted as a result of a distribution that is taxable to our common stockholders, such as a cash dividend, holders of our Series A Preferred Stock may be deemed to have received a dividend subject to U.S. federal income tax without the receipt of any cash. In addition, a failure to adjust (or to adjust adequately) the conversion rate after an event that increases the proportionate interest of the holders of Series A Preferred Stock in us could be treated as a deemed taxable dividend to such holders. If a “fundamental change” (as defined in the Certificate of Designations for the Series A Preferred Stock) occurs, under some circumstances, we will increase the conversion rate for shares of Series A Preferred Stock converted in connection with such fundamental change. If a holder of the Series A Preferred Stock is not a non-U.S. holder (as defined below), any deemed dividend may be subject to U.S. federal withholding tax at a 30% rate, or such lower rate as may be specified by an applicable income tax treaty, which may be set off against subsequent payments on the Series A Preferred Stock.

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: (i) an individual who is a citizen or resident of the United States; (ii) 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; (iii) an estate the income of which is subject to U.S. federal income tax regardless of its source; or (iv) a trust (i) the administration of which 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 holder of our Series A Preferred Stock is a non-U.S. holder, dividends on our Series A Preferred Stock that are paid in shares may be subject to U.S. federal withholding tax in the same manner as a cash dividend, which the withholding agent might satisfy through a sale of a portion of the shares such holder receives as a dividend or through withholding of other amounts payable to such holder.

We may elect to pay dividends on our Series A Preferred Stock in shares of Series A Preferred Stock rather than in cash. Any such stock dividends paid to a holder of our Series A Preferred Stock will be taxable in the same manner as cash dividends and, if such holder is a non-U.S. holder, may be subject to U.S. federal withholding tax at a 30% rate, or such lower rate as may be specified by an applicable income tax treaty. Any required withholding tax might be satisfied by the withholding agent through a sale of a portion of the shares holders of our Series A Preferred Stock receive as a dividend or might be withheld from cash dividends or sales proceeds subsequently paid or credited to such holders.

Non-U.S. holders of our Series A Preferred Stock, Series B Preferred Stock or our Class A Common Stock could, in certain situations, be subject to U.S. federal income tax upon a sale, exchange, conversion or other disposition of such stock.

We believe that we are a “United States real property holding corporation” and likely will remain one in the foreseeable future. As a result, non-U.S. holders that own (or are treated as owning under constructive ownership rules) more than a specified amount of our Series A Preferred Stock, Series B Preferred Stock or our Class A Common Stock during a specified time period may be subject to U.S. federal income tax on a sale, exchange, conversion or other disposition of such stock and may be required to file a U.S. federal income tax return.

Because we currently have no plans to pay cash dividends on our Class A Common Stock, you may not receive any return on investment unless you sell your Class A Common Stock for a price greater than that which you paid for it.

We currently do not expect to pay any cash dividends on our Class A Common Stock. Any future determination to pay cash dividends or other distributions on our Class A Common Stock will be at the discretion of the board of directors and will be dependent on our earnings, financial condition, operation results, capital requirements, and contractual, regulatory and other restrictions, including restrictions contained in the senior secured credit facility or agreements governing any existing and future outstanding indebtedness we or our subsidiaries may incur, on the payment of dividends by us or by our subsidiaries to us, and other factors that our board of directors deems relevant.

As a result, you may not receive any return on an investment in our Class A Common Stock unless you sell the Class A Common Stock for a price greater than that which you paid for it.

Some of our total outstanding shares are restricted from immediate resale but may be sold into the market in the future. This could cause the market price of our Class A Common Stock to drop significantly, even if our business is doing well.

As of December 31, 2017, KLR Sponsor and Tema held approximately 86.7% of our issued and outstanding shares of Class A Common Stock, including Class A Common Stock issuable upon exchange of Class B Common Stock. While the SHRRA restricts, except in certain circumstances, KLR Sponsor and Tema from transferring any of their common stock until one year following the date of the consummation of the Transaction, these shares may be sold after the expiration of the lock-up period. As restrictions on resale end, the market price of our Class A Common Stock could decline if the holders of currently restricted shares sell them or are perceived by the market as intending to sell them. Additionally, the Tax Receivable Agreement grants Tema the right to prevent certain dispositions of the assets we acquired in the Transaction for a period of up to three years following the closing of the Transaction.

Additionally, in connection with the Transaction, we issued a total of 95,000 shares of Series A Preferred Stock (convertible into Class A Common Stock) and 9,000,000 warrants (exercisable for shares of Class A Common Stock), and have a total of 25,594,158 warrants outstanding at December 31, 2017. To the extent the Class A Common Stock that is issuable upon conversion or exercise of these securities is sold, the market price of our Class A Common Stock could decline.

Holders of our Series B Preferred Stock have certain limited consent rights that could prevent us from taking certain corporate actions, and as a result may adversely affect our business, operating results and stock price.

Holders of our Series B Preferred Stock have certain limited consent rights with respect to our ability to take certain corporate actions, including the following:

- the issuance, authorization or creation of any class or series of stock senior to or on parity with the Series B Preferred Stock;
- the incurrence of additional indebtedness, provided that such indebtedness may be incurred if, after giving pro forma effect to the incurrence and any application of the proceeds thereof, we maintain a Leverage Ratio (as defined in the Certificate of Designations for the Series B Preferred Stock) of less than 4.00 to 1.00;
- the issuance or incurrence of high-yield debt, unless the debt (A) does not have an all-in interest rate together with any component of yield greater than the Notes (as defined below) and a make-whole provision less favorable than the Second Lien Notes and (B) is used to refinance the Second Lien Notes;
- the entry into any joint venture agreement or issuance of equity securities of our subsidiaries, other than to us or our wholly-owned subsidiaries;
- sales of certain property having a fair market value greater than $15.0 million in any fiscal year and $40.0 million in the aggregate;
- and certain property acquisitions or investments in excess of $15.0 million in any fiscal year and $40.0 million in the aggregate, unless such acquisitions or investments are financed solely using our common equity (or cash proceeds of the issuance of our common equity).

The consent rights of the holders of our Series B Preferred Stock could prevent us from obtaining future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities, and as a result may adversely affect our business, operating results and stock price.

Anti-takeover provisions contained in our amended and restated charter, as well as provisions of Delaware law, could impair a takeover attempt.

Our amended and restated certificate of incorporation and bylaws contain provisions that may discourage unsolicited takeover proposals that stockholders may consider to be in their best interests. We are also subject to anti-takeover provisions under Delaware law, which could delay or prevent a change of control. Together these provisions may make more difficult the removal of management and may discourage transactions that otherwise could involve payment of a premium over prevailing market prices for our securities. These provisions include:

- a staggered board providing for three classes of directors, which limits the ability of a stockholder or group to gain control of our board;

- no cumulative voting in the election of directors, which limits the ability of minority stockholders to elect director candidates;

- the right of our board of directors to elect a director to fill a vacancy created by the expansion of the board of directors or the resignation, death, or removal of a director in certain circumstances, which prevents stockholders from being able to fill vacancies on our board of directors;

- the ability of our board of directors to determine whether to issue shares of our preferred stock and to determine the price and other terms of those shares, including preferences and voting rights, without stockholder approval, which could be used to significantly dilute the ownership of a hostile acquirer;

- the ability of each of Tema or KLR Sponsor to call a special meeting of stockholders, provided that such person owns 15% or more of the outstanding shares of common stock until the Trigger Date, and thereafter prohibit such ability;

- a prohibition on stockholders calling a special meeting upon and following the Trigger Date, which forces stockholder action to be taken at an annual or special meeting of our stockholders called by the board;

- the requirement that a meeting of stockholders may be called only by the board of directors after the Trigger Date, which may delay the ability of our stockholders to force consideration of a proposal or to take action, including the removal of directors;

- providing that after the Trigger Date directors may be removed prior to the expiration of their terms by stockholders only for cause or upon the affirmative vote of 75% of the voting power of all outstanding shares of the combined company;

- a requirement that changes or amendments to the certificate of incorporation or the bylaws must be approved (i) before the Trigger Date, by a majority of the voting power of outstanding common stock of the combined company, which such majority shall include at least 80% of the shares then held by KLR Sponsor and Tema, and (ii) thereafter, certain changes or amendments must be approved by at least 75% of the voting power of outstanding common stock of the combined company; and

- advance notice procedures that stockholders must comply with in order to nominate candidates to our board of directors or to propose matters to be acted upon at a stockholders' meeting, which may discourage or deter a potential acquirer from conducting a solicitation of proxies to elect the acquirer's own slate of directors or otherwise attempting to obtain control of the Company.

Changes in laws or regulations, or a failure to comply with any laws and regulations, may adversely affect our business, investments and results of operations.

We are subject to laws, regulations and rules enacted by national, regional and local governments and NASDAQ. In particular, we are required to comply with certain SEC, NASDAQ and other legal or regulatory requirements. Compliance with, and monitoring of, applicable laws, regulations and rules may be difficult, time consuming and costly. Those laws, regulations and rules and their interpretation and application may also change from time to time and those changes could have a material adverse effect on our business, investments and results of operations. In addition, a failure to comply with applicable laws, regulations and rules, as interpreted and applied, could have a material adverse effect on our business and results of operations.

We may be required to make payments under the Tax Receivable Agreement for certain tax benefits that we may claim, and the amounts of such payments could be significant.

In connection with the closing of the Transaction, we entered into the Tax Receivable Agreement with Tema. This agreement generally provides for the payment by us to Tema of 90% of the net cash savings, if any, in U.S. federal, state and local income tax and franchise tax that we actually realize (computed using simplifying assumptions to address the impact of state and local taxes) or are deemed to realize in certain circumstances in periods after the Transaction as a result of certain increases in the tax basis in the assets of Rosehill Operating and certain benefits attributable to imputed interest. We will retain the benefit of the remaining 10% of these cash savings.

The term of the Tax Receivable Agreement will continue until all tax benefits that are subject to the Tax Receivable Agreement have been utilized or expired, unless we exercise our right to terminate the Tax Receivable Agreement early within thirty (30) days of certain mergers or other changes of control (or the Tax Receivable Agreement is terminated early due to our breach of a material obligation thereunder), and we make the termination payment specified in the Tax Receivable Agreement. In addition, payments we make under the Tax Receivable Agreement will be increased by any interest accrued from the due date (without extensions) of the corresponding tax return.

The payment obligations under the Tax Receivable Agreement are our obligations and not obligations of Rosehill Operating, and we expect that the payments we will be required to make under the Tax Receivable Agreement will be substantial. Estimating the amount and timing of payments that may become due under the Tax Receivable Agreement is by its nature imprecise. For purposes of the Tax Receivable Agreement, cash savings in tax generally are calculated by comparing our actual tax liability (determined by using the actual applicable U.S. federal income tax rate and an assumed combined state and local income tax rate) to the amount we would have been required to pay had we not been able to utilize any of the tax benefits subject to the Tax Receivable Agreement. The actual increase in tax basis, as well as the amount and timing of any payments under the Tax Receivable Agreement, are dependent upon significant future events and assumptions, including the timing of the redemptions of Rosehill Operating Common Units, the price of our Class A Common Stock at the time of each redemption, the extent to which such redemptions are taxable transactions, the amount of Tema’s tax basis in its Rosehill Operating Common Units at the time of the relevant redemption, the depreciation and amortization periods that apply to the increase in tax basis, the amount and timing of taxable income we generate in the future, the U.S. federal income tax rates then applicable, and the portion of our payments under the Tax Receivable Agreement that constitute imputed interest or give rise to depreciable or amortizable tax basis. The payments under the Tax Receivable Agreement will not be conditioned upon a holder of rights under the Tax Receivable Agreement having a continued ownership interest in us or Rosehill Operating.

In certain cases, payments under the Tax Receivable Agreement may be accelerated and/or significantly exceed the actual benefits, if any, we realize in respect of the tax attributes subject to the Tax Receivable Agreement.

If we elect to terminate the Tax Receivable Agreement early within thirty (30) days of certain mergers or other changes of control or it is terminated early due to our breach of a material obligation thereunder, our obligations under the Tax Receivable Agreement would accelerate and we would be required to make a substantial immediate lump-sum payment. This payment would equal the present value of the hypothetical future payments that could be required to be paid under the Tax Receivable Agreement (determined by applying a discount rate equal to the one-year London Interbank Offered Rate ("LIBOR") plus 150 basis points). The calculation of hypothetical future payments will be based upon certain assumptions and deemed events set forth in the Tax Receivable Agreement, including (i) the assumption that we have sufficient taxable income to fully utilize the tax benefits covered by the Tax Receivable Agreement and (ii) the assumption that any Rosehill Operating Common Units (other than those held by us) outstanding on the termination date are deemed to be exchanged on the termination date. Any early termination payment may be made significantly in advance of the actual realization, if any, of the future tax benefits to which the termination payment relates.

Upon an early termination of the Tax Receivable Agreement, we could be required to make payments under the Tax Receivable Agreement that exceed our actual cash tax savings, if any, in respect of the tax attributes subject to the Tax Receivable Agreement. In these situations, our obligations under the Tax Receivable Agreement could have a substantial negative impact on our liquidity and could have the effect of delaying, deferring or preventing certain mergers, asset sales, or other forms of business combinations or changes of control. For example, if the Tax Receivable Agreement had been terminated immediately after the filing of this Annual Report on Form 10-K, the estimated termination payments would, in the aggregate, have been approximately $50 million (calculated using a discount rate equal to one-year LIBOR plus 150 basis points, applied against an undiscounted liability of $61 million, based upon the last reported closing sale price of our Class A Common Stock on December 31, 2017). The foregoing number is merely an estimate and the actual payments could differ materially. There can be no assurance that we will be able to finance our obligations under the Tax Receivable Agreement.

In the event that we elect to terminate the Tax Receivable Agreement early within thirty (30) days of certain mergers or other changes of control, the consideration payable to holders of our Class A Common Stock could be substantially reduced.

If we elect to terminate the Tax Receivable Agreement early within thirty (30) days of certain mergers or other changes of control, we would be obligated to make a substantial, immediate lump-sum payment, and such payment may be significantly in advance of, and may materially exceed, the actual realization, if any, of the future tax benefits to which the payment relates. As a result of this payment obligation, holders of our Class A Common Stock could receive substantially less consideration in connection with a change of control transaction than they would receive in the absence of such obligation. Further, our payment obligations under the Tax Receivable Agreement will not be conditioned upon Tema having a continued interest in us or Rosehill Operating. Accordingly, Tema's interests may conflict with those of the holders of our Class A Common Stock. Please read "Risk Factors - Risks Related to the Class A Common Stock and Our Capital Structure - In certain cases, payments under the Tax Receivable Agreement may be accelerated and/or significantly exceed the actual benefits we realize, if any, in respect of the tax attributes subject to the Tax Receivable Agreement" and "Certain Relationships and Related Party Transactions - Tax Receivable Agreement."

We will not be reimbursed for any payments made under the Tax Receivable Agreement in the event that any tax benefits are subsequently disallowed.

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

In certain circumstances, Rosehill Operating will be required to make tax distributions and tax advances to its unitholders, and the tax distributions and tax advances that Rosehill Operating will be required to make may be substantial.

Pursuant to the Second Amended LLC Agreement, Rosehill Operating will make generally pro rata cash distributions, or tax distributions, to its unitholders, including us, in an amount sufficient to allow us to pay our taxes and to allow us to make payments under the Tax Receivable Agreement with Tema. In addition to these pro rata distributions, certain Rosehill Operating unitholders will be entitled to receive tax advances in an amount sufficient to allow each such unitholder to pay its respective taxes on such holder’s allocable share of Rosehill Operating’s taxable income. Any such tax advance will be calculated after taking into account certain other distributions or payments received by the unitholders from Rosehill Operating. Under the applicable tax rules, Rosehill Operating is required to allocate net taxable income disproportionately to its members in certain circumstances. Tax advances will be determined based on an assumed individual tax rate and will be repaid upon exercise of Tema's redemption right.

Funds used by Rosehill Operating to satisfy its tax distribution and tax advance obligations will not be available for reinvestment in our business. Moreover, the tax distributions and tax advances Rosehill Operating will be required to make may be substantial, and because of the disproportionate allocation of net taxable income, may exceed the actual tax liability for some of the existing owners of Rosehill Operating.

The JOBS Act permits “emerging growth companies” like us to take advantage of certain exemptions from various reporting requirements applicable to other public companies that are not emerging growth companies.

We qualify as an “emerging growth company” as defined in the JOBS Act. As such, we take advantage of certain exemptions from various reporting requirements applicable to other public companies that are not emerging growth companies for as long as we continue to be an emerging growth company, including (i) the exemption from the auditor attestation requirements with respect to internal control over financial reporting under Section 404 of the Sarbanes-Oxley Act, (ii) the exemptions from say-on-pay, say-on-frequency and say-on-golden parachute voting requirements and (iii) reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements. As a result, our stockholders may not have access to certain information they deem important. We will remain an emerging growth company until the earliest of (i) the last day of the fiscal year following the fifth anniversary of the date of our initial public offering, (ii) the last day in the fiscal year in which we have total annual gross revenue of at least $1.07 billion (as adjusted for inflation pursuant to SEC rules from time to time), (iii) the date in which we are deemed to be a large accelerated filer, which means the market value of our Class A Common Stock that is held by non-affiliates exceeds $700 million as of the last business day of our prior second fiscal quarter, or (iv) the date on which we have issued more than $1.0 billion in non-convertible debt during the prior three-year period.

In addition, Section 107 of the JOBS Act provides that an emerging growth company can take advantage of the exemption from complying with new or revised accounting standards provided in Section 7(a)(2)(B) of the Securities Act as long as we are an emerging growth company. An emerging growth company can therefore delay the adoption of certain accounting standards until those standards would otherwise apply to private companies. The JOBS Act provides that a company can elect to opt out of the extended transition period and comply with the requirements that apply to non-emerging growth companies, but any such election to opt out is irrevocable. We have elected not to opt out of such extended transition period, which means that when a standard is issued or revised and it has different application dates for public or private companies, we, as an emerging growth company, can adopt the new or revised standard at the time private companies adopt the new or revised standard. This may make comparison of our financial statements with another public company which is neither an emerging growth company nor an emerging growth company which has opted out of using the extended transition period difficult or impossible because of the potential differences in accountant standards used.

We cannot predict if investors will find our Class A Common Stock less attractive because we will rely on these exemptions. If some investors find our Class A Common Stock less attractive as a result, there may be a less active trading market for our Class A Common Stock and our stock price may be more volatile.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Our properties

Our properties are located within the Northern and Southern Delaware Basins, a sub-basin of the 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 Permian 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 horizontal and vertical target formations, favorable operating environment, high oil and liquids-rich natural gas content, mature infrastructure, well-developed network of oilfield service providers, long-lived reserves with consistent reservoir quality and historically high drilling success rates. According to the U.S. Energy Information Administration, the Permian Basin is the most prolific unconventional oil producing area in the U.S. and accounts for nearly half of the active drilling rigs in the U.S. as of December 31, 2017.

Oil and Natural Gas Reserves

Estimation and review of proved reserves

Proved reserve estimates as of December 31, 2017 and 2016 were prepared by Ryder Scott, L.P. ("Ryder Scott"), our independent petroleum engineer. Proved reserve estimates as of December 31, 2015 were prepared internally by management. 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 our independent petroleum engineer's proved reserve report as of December 31, 2017 is attached as an exhibit to this Annual Report on Form 10-K.

We maintain an internal staff of petroleum engineers and geoscience professionals to work closely with our independent petroleum engineers to ensure the integrity, accuracy and timeliness of the data used to calculate the proved reserves relating to our assets. Our internal technical team members meet with our independent petroleum engineer 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, subsurface geologic data and operating and development costs. Our Vice President of Engineering, is primarily responsible for overseeing the preparations of all of our reserve estimates. He is a petroleum engineer with 28 years of petroleum engineering experience, including experience with both offshore conventional and onshore unconventional field developments. The preparation of our proved reserve estimates was 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 producing formations, well targets and the development plan by our Vice President of Geology and Vice President of Engineering;
- review and verification of historical production data, which data is based on actual production as reported by us;
- review of well by well reserve estimates by independent reserve engineers;
- review by our Vice President of Engineering of all of our reported proved reserves, including the review of all significant reserve changes and all new PUD additions;
- direct reporting responsibilities by our Vice President of Engineering to our Chief Executive Officer; and
- verification of property ownership interests by our land department.

Under the rules promulgated by the SEC, 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 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). 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 December 31, 2017, 2016 and 2015 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 established under SEC rules. 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 four broad categories or methods: (i) production performance-based methods; (ii) material balance-based methods; (iii) volumetric-based methods; and (iv) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserves for PDP wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to similar production, both of which are considered to provide a reasonably high degree of accuracy. Non-producing reserve estimates for developed and undeveloped properties were forecasted using analogy methods. This method provides a reasonably high degree of accuracy for predicting proved developed non-producing and PUD locations for our properties, due to the abundance of analog data.

To estimate economically recoverable proved reserves and related future net cash flows, Ryder Scott and management considered with respect to the carve-out figures many factors and assumptions, including the use of reservoir parameters derived from geological and engineering data, which cannot be measured directly, economic criteria based on current costs, 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, historical well costs and operating expense data.

Summary of Oil, Natural Gas and NGL Reserves

At December 31, 2017, our estimated proved oil and natural gas reserves were 31,131 MBoe and determined in accordance with the rules and regulations of the SEC. Based on this report, at December 31, 2017, our proved reserves were approximately 59% oil, 21% natural gas, 20% NGLs and 43% proved developed. The calculated percentages include proved developed non-producing reserves. At December 31, 2017, all of our proved reserves were located in the Permian Basin.

The following table presents our estimated net proved oil, natural gas and natural gas liquids reserves as of the fiscal years indicated:

	December 31,		
	2017 (1)	2016 (2)	2015 (3)
Proved reserves:			
Oil (MBbls)	18,436	7,356	5,652
Natural gas (MMcf)	39,316	17,355	13,899
NGL (MBbls)	6,142	2,985	1,994
Total (MBoe)	31,131	13,234	9,963
Proved developed reserves:			
Oil (MBbls)	8,814	3,068	2,698
Natural gas (MMcf)	14,171	10,574	10,116
NGL (MBbls)	2,285	1,802	1,481
Total (MBoe)	13,461	6,633	5,865
Proved undeveloped reserves:			
Oil (MBbls)	9,622	4,288	2,954
Natural gas (MMcf)	25,145	6,781	3,783
NGL (MBbls)	3,857	1,183	513
Total (MBoe)	17,670	6,601	4,098
Oil and Natural Gas Prices:			
Oil - WTI posted price per Bbl	$ 51.34	$ 42.75	$ 50.28
Natural gas - Henry Hub spot price per MMBtu	$ 2.98	$ 2.49	$ 2.58
NGL - per Bbl	$ 31.82	$ 11.73	$ 13.83

(1) Estimated net proved reserves were determined using average first-day-of-the-month prices for the prior twelve months in accordance with SEC guidance. For oil, the average West Texas Intermediate posted price of $51.34 per barrel as of December 31, 2017 was adjusted for quality, transportation fees, and a regional price differential. For natural gas volumes, the average Henry Hub spot price of $2.98 per MMBtu as of December 31, 2017 was adjusted for energy content and a regional price differential. For December 31, 2017, NGLs were priced at $31.82 per barrel using Mont Belvieu pricing, as adjusted, and not as a percentage of West Texas Intermediate. All prices are held constant throughout the producing life of the properties.

(2) Estimated net proved reserves were determined using average first-day-of-the-month prices for the prior twelve months in accordance with SEC guidance. For oil, the average West Texas Intermediate posted price of $42.75 per barrel as of December 31, 2016 was adjusted for quality, transportation fees, and a regional price differential. For natural gas volumes, the average Henry Hub spot price of $2.49 per MMBtu as of December 31, 2016 was adjusted for energy content and a regional price differential. For NGL volumes, 27.5% of the average West Texas Intermediate posted price of $42.75 per barrel, or $11.73, as of December 31, 2016 was adjusted for quality, transportation fees and a regional price differential. All prices are held constant throughout the producing life of the properties.

(3) Estimated net proved reserves were determined using average first-day-of-the-month prices for the prior twelve months in accordance with SEC guidance. For oil, the average West Texas Intermediate posted price of $50.28 per barrel as of December 31, 2015 was adjusted for quality, transportation fees and a regional price differential. For natural gas volumes, the average Henry Hub spot price of $2.58 per MMBtu as of December 31, 2015 was adjusted for energy content and a regional price differential. For NGL volumes, 27.5% of the average West Texas Intermediate posted price of $50.28 per barrel, or $13.83, as of December 31, 2015 was adjusted for quality, transportation fees and a regional price differential. All prices are held constant throughout the producing life of the properties.

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."

Additional information regarding our proved reserves can be found in the notes to our consolidated financial statements included elsewhere in this Annual Report on Form 10-K and the reserve report as of December 31, 2017, which is included as an exhibit to this Annual Report on Form 10-K.

Our proved reserves increased by 17,897 MBoe from 13,234 MBoe at December 31, 2016 to 31,131 MBoe at December 31, 2017. The increase was due to extensions of 15,157 MBoe, revisions of 5,137 MBoe, and acquisitions of 734 MBoe related to the purchase of additional working interests in various operated wells and leasehold interests in Loving County, Texas partially offset by production of 2,131 MBoe and 1,000 MBoe of divestitures. The increase due to extensions is primarily the result of the increased drilling in 2017 and the increase due to revisions is primarily due to increase oil and natural gas prices used to estimate proved reserves.

Proved undeveloped reserves (PUDs)

As of December 31, 2017, our proved undeveloped reserves totaled 9,622 MBbls of oil, 25,145 MMcf of natural gas and 3,857 MBbls of natural gas liquids, for a total of 17,760 MBoe. PUDs will be converted from undeveloped to developed as the applicable wells are drilled and begin production.

The following table summarizes the changes in PUD reserves for the year ended December 31, 2017 in MBoe:

December 31, 2016	6,601
Extensions, discoveries and other additions	7,182
Performance and price revisions	5,937
Acquisition of reserves	519
Disposition of reserves	—
Transferred to proved developed reserves	(2,569)
December 31, 2017	17,670

As of December 31, 2017, we had 28 operated PUD locations booked of which, five locations were originally booked at December 31, 2014, seven locations were originally booked at December 31, 2015 and three locations were originally booked at December 31, 2016.

During 2017, we spent a total of $31.8 million related to the development of proved undeveloped reserves, which resulted in the conversion of 2,569 MMBoe of proved undeveloped reserves to proved developed reserves. Our development plan resulted in four PUDs drilled in 2017. As of December 31, 2017, we had 5 DUCs included in PUDs which we incurred approximately $13.5 million drilling. Plans for 2018 include drilling 11 PUD targets. We believe that our progress to date in 2017 demonstrates our ability to execute on our development plan. Our development plan sets forth the remaining PUD locations to be brought to proved producing status within five years of initial booking. The future development of our proved undeveloped reserves is dependent on future commodity prices, costs and economic assumptions that align with our internal forecast as well as access to liquidity sources.

Oil and Natural Gas Production Prices and Production Costs

The prices that we receive for the oil, natural gas and natural gas liquids we produce is largely a function of market supply and demand. Demand is impacted by general economic conditions, weather and other seasonal conditions, including hurricanes and tropical storms. Over or under supply of oil or natural gas can result in substantial price volatility. Historically, commodity prices have been volatile, and we expect that volatility to continue in the future. A substantial or extended decline in oil, natural gas, and NGL prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of oil, natural gas, and NGL reserves that may be economically produced and our ability to access capital markets. Please see "Risk Factors - Risks Related to Our Operations - Oil, natural gas and NGL prices are volatile. A 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."

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

	Year Ended December 31,		
	2017	2016	2015
Production data:			
Oil (MBbls)	1,271	612	472
Natural gas (MMcf)	2,709	2,381	2,074
Natural gas liquids (MBbls)	408	358	312
Total production (MBoe)	2,131	1,367	1,130
Average daily production (Boe/d)	5,838	3,734	3,096
Average realized prices before effect of derivatives (1):			
Oil (per Bbl)	$ 48.46	$ 40.52	$ 43.62
Natural gas (per Mcf)	2.65	2.23	2.37
Natural gas liquids (per Bbl)	18.31	12.68	12.75
Average price (per Boe)	$ 35.77	$ 25.35	$ 26.09
Average price after the effect of settled derivatives (per Boe) (1)	$ 35.85	$ 22.30	$ 29.40
Average costs (per Boe)			
Lease operating expense	$ 5.11	$ 3.51	$ 4.06
Production taxes	1.66	1.13	1.16
Gathering and transportation	1.40	1.75	1.85
Depreciation, depletion and amortization	16.94	18.27	20.68
Impairment of oil and natural gas properties	0.50	—	7.20
Exploration costs	0.82	0.58	0.85
General and administrative expense	6.30	4.51	3.75
Transaction expenses	1.23	2.07	—
(Gain) loss on sale of property and equipment	(2.34)	(0.04)	0.02
Total (2)	$ 31.62	$ 31.78	$ 39.57

(1) Average prices shown in the table reflect prices both before and after the effects of commodity hedging settlements. Our calculation of such effects includes both gains and losses on cash settlements for commodity derivative transactions and premiums paid or received on options that settled during the period.

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

Drilling activity and results

The following table summarizes our drilling activity for the last three years.

	Year Ended December 31,			Year Ended December 31,		
	2017	2016	2015	2017	2016	2015
		Gross			Net	
Exploratory Wells:						
Productive (1)	15	3	2	15	2	—
Dry	—	—	—	—	—	—
Development Wells:						
Productive (1)	4	2	1	4	2	1
Dry	—	—	—	—	—	—
Total Wells						
Productive (1)	19	5	3	19	4	1
Dry holes	—	—	—	—	—	—
	19	5	3	19	4	1

(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 for which there is no production history.

Productive wells

The following table sets forth the number of productive oil and natural gas wells on our properties at December 31, 2017. This table does not include wells in which we own a royalty interest only.

	Gross Productive Wells			Net Productive Wells		
	Oil	Natural Gas	Total	Oil	Natural Gas	Total
Core Operating Areas:						
Northern Delaware Basin	29	14	43	25	14	39
Southern Delaware Basin	9	3	12	7	2	9
Total	38	17	55	32	16	48

As of December 31, 2017, we had an average working interest of 88% in 55 gross (48 net) productive wells, of which 43 gross (39 net) were horizontal wells in the Northern Delaware Basin acreage area and of which 12 gross (9 net) were vertical wells in the Southern Delaware Basin acreage area. Productive wells consist of producing wells and wells capable of production, including oil wells awaiting connection to production facilities. Gross wells are the total number of producing wells in which we have an interest and net wells are the sum of our fractional working interests owned in gross wells.

Our acreage

The following table sets forth information as of December 31, 2017 relating to our Delaware Basin 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.

Core Acreage Area:	Developed Acres Gross	Developed Acres Net	Undeveloped Acres Gross	Undeveloped Acres Net	Total Acres Gross	Total Acres Net
Northern Delaware Basin	4,624	3,041	2,040	968	6,664	4,009
Southern Delaware Basin	2,990	2,380	5,108	4,752	8,098	7,132
Total	7,614	5,421	7,148	5,720	14,762	11,141

We are the operator of approximately 95% of this acreage. In addition, we own mineral interests underlying approximately 14,762 gross (11,141 net) of these acres, with an average royalty interest of 78%. Through December 31, 2017, we have drilled 26 gross (26 net) wells in our Northern Delaware Basin leasehold acreage. As of December 31, 2017, we had 2 operated rigs running, 2 operated wells drilling and an inventory of 5 operated wells awaiting completion. We expect to continue to concentrate drilling activities within our core acreage in 2018, primarily targeting the Bone Spring and Wolfcamp formations.

Undeveloped acreage expirations

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. The following table sets forth the gross and net undeveloped acreage, as of December 31, 2017, that will expire over the next five years unless production is established within the spacing units covering the acreage or the lease is renewed or extended under continuous drilling provisions prior to the primary term expiration dates.

Expirations	2018 Gross	2018 Net	2019 Gross	2019 Net	2020 Gross	2020 Net	2021 Gross	2021 Net	2022 Gross	2022 Net
Northern Delaware Basin	1,240	868	—	—	—	—	—	—	—	—
Southern Delaware Basin	—	—	640	640	4,136	3,862	—	—	—	—
Total	1,240	868	640	640	4,136	3,862	—	—	—	—

Title to properties

We believe that we have satisfactory title to our producing properties in accordance with generally accepted industry standards. As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties for an acquisition of leasehold acreage. We perform a thorough title examination and curative work with respect to significant defects prior to either an acquisition of producing properties or prior to commencement of drilling operations on those properties. 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 our material assets. Although title to these properties is in some cases subject to encumbrances, 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.

ITEM 3. LEGAL PROCEEDINGS

From time to time, we are subject to various legal proceedings arising in the ordinary course of business, including proceedings for which we have insurance coverage. We do not believe the results of any legal proceedings, individually or in the aggregate, will have a material adverse effect on our business, financial condition, results of operations or liquidity.

ITEM 4. MINE SAFETY DISCLOSURES

None.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES.

Market Information

Our Class A Common Stock, Warrants and Units are currently quoted on NASDAQ under the symbols “ROSE” and "ROSEW", and “ROSEU,” respectively. Through April 26, 2017, our Class A Common Stock was quoted under the symbol “KLRE.” The following table sets forth, for the calendar quarter indicated, the high and low sales price per share of Class A Common Stock as reported on NASDAQ for the periods presented:

	2017		2016	
	High	Low	High	Low
Fourth Quarter	$ 10.84	$ 7.62	$ 10.50	$ 10.10
Third Quarter	$ 8.98	$ 5.52	$ 10.15	$ 9.91
Second Quarter	$ 11.69	$ 7.80	$ 10.15	$ 9.90
First Quarter	$ 10.65	$ 10.20	$ 9.95	$ 9.95

Holders of Record

Approximately 22 registered stockholders of record held our Class A Common Stock as of April 6, 2018. This number does not include owners or stockholders who beneficially own our shares through a broker or other entity who may hold shares in a “street name”.

There is no public market for our Class B Common Stock. On April 6, 2018, we had one holder of record of our Class B Common Stock.

Dividend Policy

We have not paid any cash dividends on our Class A Common Stock to date and do not currently contemplate paying dividends in the foreseeable future. The payment of cash dividends in the future will be dependent upon our revenues and earnings, if any, capital requirements and general financial condition. The payment of any future cash dividends will be within the discretion of our board of directors.

Pursuant to that certain Certificate of Designation for the Series A Preferred Stock filed with the Secretary of State of the State of Delaware on April 27, 2017, holders of Series A Preferred Stock are entitled to receive, when, as and if declared by our board of directors, cumulative dividends, payable in cash, Series A Preferred Stock, or a combination thereof, in each case, at the sole discretion of the Company, at an annual rate of 8% on the $1,000 liquidation preference per share of the Series A Preferred Stock, payable quarterly in arrears on January 15, April 15, July 15 and October 15 of each year, beginning on July 15, 2017.

Pursuant to that certain Certificate of Designation for the Series B Preferred Stock filed with the Secretary of State of the State of Delaware on December 8, 2017, holders of Series B Preferred Stock are entitled to receive, when, as and if declared by our board of directors, cumulative dividends, payable in cash, or with respect to dividends declared for any quarter ending on or prior to January 15, 2019, a combination of cash and Series B Preferred Stock, in each case, at the sole discretion of the Company, at an annual rate of 10% on the $1,000 liquidation preference per share of the Series B Preferred Stock, payable quarterly in arrears on January 15, April 15, July 15 and October 15 of each year, beginning on January 15, 2018.

Issuer Purchases of Equity Securities

Period	Total Number of Shares Purchased (1)	Average Price Paid per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs
October 2017	—	$ —	n/a	n/a
November 2017	—	—	n/a	n/a
December 2017	4,494	10.15	n/a	n/a
Total fourth-quarter 2017	4,494	$ 10.15	n/a	n/a

(1) These shares were withheld upon the vesting of employee restricted stock grants in connection with payment of required withholding taxes.

Equity Compensation Plan Information

On April 27, 2017, our stockholders approved the Rosehill Resources Inc. Long-Term Incentive Plan. See more details and discussion of the plan in Note 12 - *Stock Based Compensation*.

Plan category	**Number of securities to be issued upon exercise of outstanding options, warrants and rights**	**Weighted-average exercise price of outstanding options, warrants and rights**	**Number of securities remaining available for future issuance under equity compensation plans**
Equity compensation plans approved by security holders	713,939	$ —	6,666,605
Total	713,939	$ —	6,666,605

ITEM 6. SELECTED FINANCIAL DATA

The following selected financial data should be read in conjunction with “ITEM 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and “ITEM 8. Financial Statements and Supplementary Data,” both contained herein.

The following table shows our and Rosehill Operating’s selected consolidated historical financial information for the periods indicated. The selected historical financial balance sheet data of Rosehill Operating as of December 31, 2016 and 2015 and the statement of operations and cash flow data for the years ended December 31, 2016, 2015 and 2014 was derived from the audited carve-out historical financial statements of Tema. We have no direct operations and no significant assets other than our ownership interest in Rosehill Operating, an entity of which we act as the sole managing member and of whose Rosehill Operating Common Units we currently own approximately 17.3% (or 33.1% assuming the conversion of our Rosehill Operating Series A preferred units into Rosehill Operating Common Units). Unless the context otherwise requires, (i) prior to the completion of the Transaction, references to "Rosehill Operating" refer to the assets, liabilities and operations of the business that were contributed to Rosehill Operating Company, LLC in connection with the Transaction and (ii) following the completion of the Transaction, references to "Rosehill Operating" refer to Rosehill Operating Company, LLC.

	Year Ended December 31,			
	2017	2016	2015	2014
	(in thousands, except per share data)			
STATEMENTS OF OPERATIONS DATA				
Total revenues	$ 76,236	$ 34,645	$ 29,487	$ 43,563
Operating income (loss)	8,894	(8,803)	(15,207)	(16,504)
Net loss	(11,948)	(15,189)	(14,820)	(19,253)
Series A Preferred Stock dividends and deemed dividends	12,936	—	—	—
Series B Preferred Stock dividends, deemed dividends and return	2,447	—	—	—
Net loss attributable to Rosehill Resources Inc. common stockholders	(8,520)	(15,189)	(14,820)	(19,253)
Earnings (loss) per common share:				
Basic and diluted	$ (1.43)	$ (2.59)	$ (2.53)	(3.29)
Weighted average common shares outstanding	5,945	5,857	5,857	5,857
Pro Forma Per Share Data (in thousands, except per share data)(1)				
Pro forma net loss attributable to Rosehill Resources Inc. common stockholders	$ (8,068)	$ (12,355)		
Pro forma loss per share				
Basic and diluted	$ (1.36)	$ (2.11)		
Pro forma weighted average common shares outstanding				
Basic and diluted	5,945	5,857		
CASH FLOW DATA				
Net cash provided by (used in):				
Operating activities	$ 37,759	$ 11,461	$ 18,244	$ 25,525
Investing activities	(265,497)	(22,164)	(16,993)	(53,392)
Financing activities	243,986	(8,597)	17,519	23,457
Other financial data:				
Adjusted EBITDAX (unaudited)(2)	$ 46,766	$ 18,949	$ 21,743	$ 28,032

	December 31,		
	2017	2016	2015
BALANCE SHEET DATA			
Total current assets	$ 43,543	$ 16,343	$ 33,696
Property and equipment, net	432,615	123,373	122,873
Total assets	476,982	139,826	156,903
Total current liabilities	103,400	14,223	29,165
Long term debt, net	93,199	55,000	45,000
Mezzanine equity - Series B Preferred Stock	140,868	—	—
Total stockholders' equity / parent net investment	122,664	65,220	78,977

(1) The pro forma data is provided for illustrative purposes only. We incurred non-recurring transaction costs that were directly attributable to the Transaction of $2.6 million and $2.8 million for the years ended December 31, 2017 and 2016, respectively. Pro forma per share data was recalculated excluding transaction costs. The portion of transaction costs related to our 17% ownership was reduced from the net loss attributable to Rosehill Resources Inc. common stockholders.

(2) Adjusted EBITDAX is a non-GAAP financial measure. For a definition of Adjusted EBITDAX and a reconciliation of net income to Adjusted EBITDAX, see "Management's Discussion and Analysis of Financial Condition and Results of Operations - Non-GAAP Financial Measure".

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with the consolidated financial statements and notes thereto appearing elsewhere in this Annual Report on Form 10-K. 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 of 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, natural gas and NGLs, 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 Annual Report on Form 10-K, 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.

Overview

We are an independent oil and natural gas company focused on the acquisition, exploration, development and production of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin. Our assets are concentrated in the Delaware Basin, a sub-basin of the Permian Basin. We have drilling locations in ten distinct formations in the Delaware Basin in: the Brushy Canyon, Upper Avalon, Lower Avalon, 2nd Bone Spring Shale, 2nd Bone Spring Sand, 3rd Bone Spring Sand, 3rd Bone Spring Shale, Wolfcamp A (X/Y), Lower Wolfcamp A and Wolfcamp B, and our goal is to build a premier development and acquisition company focused on horizontal drilling in the Delaware Basin.

We have no direct operations and no significant assets other than our ownership interest in Rosehill Operating, an entity of which we act as the sole managing member and of whose common units we currently own approximately 17.3% (or 33.1%) assuming the conversion of Rosehill Operating Series A preferred units into Rosehill Operating Common Units).

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:

- production volumes;
- operating expenses on a per Barrel of oil equivalent ("Boe");
- cost of reserve additions from drilling operations; and
- Adjusted EBITDAX as defined under "Non-GAAP Financial Measure".

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. During 2015, 2016 and early 2017, 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 reflected the significant supply growth achieved in the United States as a result of shale drilling and oil production increases by certain other countries, including the efforts of Russia and Saudi Arabia 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. NGL prices generally correlate to the price of oil. Prices for domestic natural gas began to decline during the third quarter of 2014 and continued to be weak during 2015 through 2017.

This decline is primarily due to an imbalance between supply and demand across North America. Due to these and other factors, commodity prices cannot be accurately predicted.

Realized Prices

Our revenue, profitability and future growth are highly dependent on the prices we receive for our oil and natural gas production, as well as NGLs that are extracted from our natural gas during processing. The following table presents our average realized commodity prices before the effects of commodity derivative settlements:

	Year Ended December 31,		
	2017	**2016**	**2015**
Crude Oil (per Bbl)	$ 48.46	$ 40.52	$ 43.62
Natural Gas (per Mcf)	$ 2.65	$ 2.23	$ 2.37
NGLs (per Bbl)	$ 18.31	$ 12.68	$ 12.75

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, or ability to finance planned capital expenditures. Lower oil, natural gas, and NGL prices may also reduce the borrowing base under our credit agreement, which may be 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. Alternatively, higher oil and natural gas prices may result in significant non-cash fair value losses being incurred on our commodity derivatives, which could cause us to experience net losses when oil and natural gas prices rise.

A 10% change in our realized oil, natural gas and NGL prices would have changed revenue by the following amounts for the periods indicated:

	Year Ended December 31.		
	2017	**2016**	**2015**
		(In thousands)	
Oil sales	$ 6,160	$ 2,481	$ 2,060
Natural gas sales	717	530	491
NGL sales	747	453	398
Total revenues	$ 7,624	$ 3,464	$ 2,949

The prices we receive for our products are based on benchmark prices and are adjusted for quality, energy content, transportation fees, and regional price differentials. See "Results of Operations" below for an analysis of the impact changes in realized prices had on our revenues.

Sources of Our Revenues

Our revenues are derived from the sale of our oil and natural gas production, as well as the sale of NGLs that are extracted from our natural gas during processing. The following table shows the components of our revenues for the periods indicated, as well as the percentage each component contributed to total revenue.

Source of revenues (1)(2):	Year Ended December 31, 2017	2016	2015
Oil sales	81%	72%	70%
Natural gas sales	9	15	17
NGL sales	10	13	13
	100%	100%	100%

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

(2) The percentages exclude the effects of commodity derivative settlements.

Approximately 80%, 70%, and 54% of total revenues for the years ended December 31, 2017, 2016, and 2015, respectively, were from Gateway, a related-party.

Operational and Financial Highlights for the years ended December 31, 2017, 2016 and 2015

Production Results

The following table presents sales volumes for our properties for the periods indicated:

	Year Ended December 31, 2017	2016	2015
Oil (MBbls)	1,271	612	472
Natural gas (MMcf)	2,709	2,381	2,074
NGLs (MBbls)	408	358	312
Total (MBoe)	2,131	1,367	1,130
Average net daily production (Boe/d)	5,838	3,734	3,096

As reservoir pressures decline, production from a given well or formation decreases. Growth in our future 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 development projects and acquisitions is dependent on many factors, including our ability to borrow or raise capital, obtain regulatory approvals, procure contract drilling rigs and personnel and successfully identify and consummate acquisitions. Please read "Risk Factors - Risks Related to Our Operations" for a discussion of these and other risks affecting our proved reserves and production.

Derivative Activity

To achieve a more predictable cash flow and reduce exposure to adverse fluctuations in commodity prices, we have historically used commodity derivative instruments, such as swaps, two-way costless collars, and three-way costless collars, to hedge price risk associated with a portion of our anticipated oil and natural gas production. By removing a significant portion of the price volatility associated with our oil and natural gas production, we will mitigate, but not eliminate, the potential negative effects of declines in benchmark oil and natural gas prices on our cash flow from operations for those periods. However, in a portion of our current positions, hedging activity may also reduce our ability to benefit from increases in oil and natural gas prices. We will sustain losses to the extent our commodity derivative contract prices are lower than market prices and, conversely, we will sustain gains to the extent our commodity derivative contract prices are higher than market prices. In certain circumstances, where we have unrealized gains in our commodity derivatives portfolio, we may choose to restructure existing commodity derivative contracts or enter into new transactions to modify the terms of current contracts in order to realize the current value of our existing positions. We are under no obligation to hedge a specific portion of our production.

A description of our derivative financial instruments is provided below:

- A swap has an established fixed price. When the settlement price is below the fixed price, the counterparty pays us an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is above the fixed price, we pay our counterparty an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract value.

- A two-way costless collar is an arrangement that contains a fixed floor price (purchased put option) and a fixed ceiling price (sold call option) based on an index price which, in aggregate, have no net cost. At the contract settlement date, (1) if the index price is higher than the ceiling price, we pay the counterparty the difference between the index price and ceiling price, (2) if the index price is between the floor and ceiling prices, no payments are due from either party, and (3) if the index price is below the floor price, we will receive the difference between the floor price and the index price.

- A three-way costless collar is an arrangement that contains a purchased put option, a sold call option and a sold put option based on an index price which, in aggregate, have no net cost. At the contract settlement date, (1) if the index price is higher than the sold call strike price, we pay the counterparty the difference between the index price and sold call strike price, (2) if the index price is between the purchased put strike price and the sold call strike price, no payments are due from either party, (3) if the index price is between the sold put strike price and the purchased put strike price, we will receive the difference between the purchased put strike price and the index price, and (4) if the index price is below the sold put strike price, the Company will receive the difference between the purchased put strike price and the sold put strike price.

- A purchased put option has an established floor price. The buyer of the put option pays the seller a premium to enter into the put option. When the settlement price is below the floor price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is above the floor price, the put option expires worthless.

- A sold call option has an established ceiling price. The buyer of the call option pays the seller a premium to enter into the call option. When the settlement price is above the ceiling price, the seller pays the buyer an amount equal to the difference between the settlement price and the strike price multiplied by the hedged contract volume. When the settlement price is below the ceiling price, the call option expires worthless.

Below is a summary of our open commodity derivative instrument positions for 2018 and beyond as of December 31, 2017:

	2018	2019	2020	2021	2022
Commodity derivative swaps					
Oil:					
Notional volume (Bbls)	2,350,000	1,704,000	960,000	360,000	250,000
Weighted average fixed price ($/Bbl)	$ 54.28	$ 52.85	$ 51.37	$ 50.69	$ 50.21
Natural Gas:					
Notional volume (MMBtu)	4,040,000	2,160,000	1,500,000	1,200,000	1,000,000
Weighted average fixed price ($/MMbtu)	$ 3.10	$ 2.89	$ 2.84	$ 2.86	$ 2.86

After December 31, 2017 and through April 6, 2018, the Company entered into the following commodity derivative instruments.

	2018	2019	2020	2021	2022
Commodity derivative swaps					
Oil:					
Notional volume (Bbls)	360,000	960,000	—	—	50,000
Weighted average fixed price ($/Bbl)	$ 62.05	$ 55.19	$ —	$ —	$ 50.89
Natural Gas:					
Notional volume (MMBtu)	—	60,000	—	—	200,000
Weighted average fixed price ($/Mbtu)	$ —	$ 2.65	$ —	$ —	$ 2.93
Commodity derivative two-way collars					
Oil:					
Notional volume (Bbls)	210,000	420,000	—	—	—
Weighted average ceiling price ($/Bbl)	$ 58.25	$ 60.03	$ —	$ —	$ —
Weighted average floor price ($/Bbl)	$ 55.00	$ 53.14	$ —	$ —	$ —
Commodity derivative three-way collars					
Oil:					
Notional volume (Bbls)	—	240,000	—	—	—
Weighted average ceiling price ($/Bbl)	$ —	$ 61.75	$ —	$ —	$ —
Weighted average floor price ($/Bbl)	$ —	$ 52.50	$ —	$ —	$ —
Weighted average sold put option price ($/Bbl)	$ —	$ 42.50	$ —	$ —	$ —

See Note 4 - *Derivative Instruments* in the Consolidated Financial Statements under Part II, Item 8 of this Annual Report on Form 10-K for additional information about our derivatives

Principal Components of Our Cost Structure

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.

Lease Operating Expenses. Lease operating expenses ("LOE") are the costs incurred in the operation of producing properties and workover costs. Expenses for direct labor, water/gas injection, water handling and disposal, compressor rental, and chemicals comprise the most significant portion of our LOE. Certain items, such as direct labor and compressor rental, generally remain relatively fixed across broad production volume ranges, but can fluctuate depending on activities performed during a specific period. For example, repairs to our pumping equipment or surface facilities result in increased LOE in periods during which they are performed. Certain of our operating cost components are variable and increase or decrease as the level of produced hydrocarbons and / or water increases or decreases. For example, we incur water disposal costs in connection with various production-related activities, such as trucking water for disposal until connection can be made to a water disposal well. We are also subject to ad valorem taxes, which is included in LOE, in the counties where our production is located. Ad valorem taxes are generally based on the valuation of our oil and natural gas properties.

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 costs and could cause fluctuations when comparing LOE on a period to period basis.

Production 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 the changes in oil, natural gas, and NGL revenues.

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

Depreciation, Depletion, and Amortization. Depreciation, depletion, and amortization ("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 associated with our development and acquisition efforts and all successful exploration efforts, which are then depleted using the unit of production method. Deprecation of the cost of other property, plant and equipment is generally calculated using the straight-line depreciation method over the useful lives of the assets.

Accretion Expense. Accretion expense is the periodic accreting of the present value of the estimated asset retirement liability to reflect the passage of time.

Impairment Expense. We review our proved properties and unproved leasehold costs for impairment whenever events and changes in circumstances indicate that a decline in the recoverability of their carrying value may have occurred. Impairment is reviewed and recorded on a property-by-property basis. Please read "-Critical Accounting Policies and Estimates-Impairment of Oil and Natural Gas Properties" for further discussion.

General and Administrative Expense. General and administrative ("G&A") expense reflects costs incurred for overhead, including compensation 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. A portion of these expenses prior to the Transaction have been allocated to us from Tema (on the basis of direct usage when identifiable with the remainder allocated proportionately on a Boe basis).

Transaction Expense. Transaction expense reflects costs incurred in connection with the Transaction. Under the terms of the Business Combination Agreement dated December 31, 2016 (the "Business Combination Agreement"), Tema and Rosemore were entitled to be reimbursed for transaction expenses incurred through the closing of the transaction.

Interest Expense, Net. Interest paid to lenders under the revolving credit facility and other borrowings and interest income earned on cash balances, is reflected in interest expense, net.

Non-GAAP Financial Measure

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 (loss) before interest expense, net, income taxes, DD&A, accretion, impairment of oil and natural gas properties, exploration costs, stock based compensation, (gains) losses on commodity derivatives excluding net cash receipts (payments) on settled commodity derivatives, one-time costs incurred in connection with the Transaction, gains and losses from the sale of assets, (gains) losses on asset retirement obligation settlements, and other non-cash operating items. Adjusted EBITDAX is not a measure of net income as determined by U.S. GAAP.

Management believes Adjusted EBITDAX is useful because it allows them to more effectively evaluate our operating performance and compare our results of operations from period to period and against our peers without regard to 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 U.S. GAAP or as an indicator of our operating performance or liquidity. 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, none of which are components of Adjusted EBITDAX. Our presentation of Adjusted EBITDAX should not be construed as an inference that its results will be unaffected by unusual or non-recurring items. Our computations of Adjusted EBITDAX may not be comparable to other similarly titled measures of other companies.

The following table presents an unaudited reconciliation of net loss, the most directly comparable financial measure calculated and presented in accordance with U.S. GAAP, to Adjusted EBITDAX.

Non-GAAP Financial Measure

	Year Ended December 31,		
	2017	**2016**	**2015**
Net loss reconciliation to Adjusted EBITDAX (in thousands):			
Net loss	$ (11,948)	$ (15,189)	$ (14,820)
Interest expense, net	2,532	1,822	3,247
Income tax expense (benefit)	1,690	148	108
Depreciation, depletion, amortization and accretion	36,091	24,965	23,364
Impairment of oil and natural gas properties	1,061	—	8,131
(Gain) loss on unsettled commodity derivatives, net	16,553	3,345	735
Transaction costs	2,618	2,834	—
Stock based compensation	1,245	—	—
Exploration costs	1,747	794	960
(Gain) loss on sale of oil and natural gas properties and other property and equipment	(4,995)	(50)	18
Other (income) expense, net	172	280	—
Adjusted EBITDAX	$ 46,766	$ 18,949	$ 21,743

Factors Affecting the Comparability of Our Future Financial Data Results to the Historical Financial Results of Rosehill Operating

Our future results of our operations may not be comparable to the historical results of operations of Rosehill Operating for the periods presented due to the following reasons:

Income Taxes. Rosehill Operating is a limited liability company that is treated as a partnership for U.S. federal income tax purposes and for purposes of certain state and local income taxes. Rosehill Operating is not subject to U.S. federal income taxes. However, Rosehill Operating is subject to the Texas margin tax at a rate of 0.75%. Any taxable income or loss generated by Rosehill Operating is passed through to and included in the taxable income or loss of its members, including us, on a pro rata basis. We are a corporation and are subject to U.S. federal income taxes, in addition to state and local income taxes with respect to its allocable share of any taxable income or loss of Rosehill Operating, as well as any stand-alone income or loss generated by us.

In connection with the closing of the Transaction, we entered into a Tax Receivable Agreement with Tema. This agreement generally provides for the payment by us to Tema of 90% of the net cash savings, if any, in U.S. federal, state and local income tax and franchise tax that we actually realize (computed using simplifying assumptions to address the impact of state and local taxes) or are deemed to realize in certain circumstances in periods after the Transaction as a result of certain increases in the tax basis in the assets of Rosehill Operating and certain benefits attributable to imputed interest. We will retain the benefit of the remaining 10% of these cash savings.

Payments will generally be made under the Tax Receivable Agreement as we realize actual cash tax savings in periods after the Transaction from the tax benefits covered by the Tax Receivable Agreement. However, if the Tax Receivable Agreement terminates early, either at our election in connection with certain mergers or other changes of control or as a result of our breach of a material obligation thereunder, we could be required to make a substantial, immediate lump sum payment in advance of any actual cash tax savings. We will be dependent on Rosehill Operating to make distributions to us in an amount sufficient to cover our obligations under the Tax Receivable Agreement.

Public Company Expenses. We incur direct G&A expense 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 G&A expenses are not included in Rosehill Operating's historical financial results of operations prior to the Transaction date of April 27, 2017.

Results of Operations

Year ended December 31, 2017 compared to year ended December 31, 2016

Oil, Natural Gas and NGL Sales 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:

	Year Ended December 31,			
	2017	2016	Change	Change %
Revenues *(In thousands)*:				
Oil sales	$ 61,596	$ 24,807	$ 36,789	148%
Natural gas sales	7,171	5,304	1,867	35
NGL sales	7,469	4,534	2,935	65
Total revenues	$ 76,236	$ 34,645	$ 41,591	120%
Average realized prices before effect of derivatives:				
Oil (per Bbl)	$ 48.46	$ 40.52	$ 7.94	20%
Natural gas (per Mcf)	2.65	2.23	0.42	19
Natural gas liquids (per Bbl)	18.31	12.68	5.63	44
Average realized price (per Boe)	$ 35.77	$ 25.35	$ 10.42	41%
Average price after effect of settled derivatives (per Boe)	$ 35.85	$ 22.30	$ 13.55	61%
Net Production:				
Oil (MBbls)	1,271	612	659	108%
Natural gas (MMcf)	2,709	2,381	328	14
NGL (MBbls)	408	358	50	14
Total (MBoe)	2,131	1,367	764	56%
Average daily net production volume:				
Oil (Bbls/d)	3,483	1,673	1,810	108%
Natural gas (Mcf/d)	7,423	6,506	917	14
NGLs (Bbls/d)	1,118	977	141	14
Total (Boe/d)	5,838	3,734	2,104	56%

Total revenues increased by approximately $41.6 million, or 120%, from December 31, 2016 to December 31, 2017. The increase in total revenues was due to higher sales volumes and higher average sales prices. The increase in average sales price contributed approximately $22.2 million of the increase in total revenues and the increase in sales volume contributed approximately $19.4 million of the increase in total revenues. The increase in sales volume is primarily attributable to additional wells going into production in 2017.

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 operating expenses for the periods indicated:

	Year Ended December 31,			
	2017	2016	Change	Change %
Operating expenses *(in thousands)*:				
Lease operating expense	$ 10,881	$ 4,800	$ 6,081	127 %
Production taxes	3,535	1,541	1,994	129
Gathering and transportation	2,976	2,398	578	24
Depreciation, depletion, amortization and accretion	36,091	24,965	11,126	45
Impairment of oil and natural gas properties	1,061	—	1,061	100
Exploration costs	1,747	794	953	120
General and administrative, excluding stock based compensation	12,183	6,166	6,017	98
Stock based compensation	1,245	—	1,245	100
Transaction costs	2,618	2,834	(216)	(8)
Gain on sale of property and equipment	(4,995)	(50)	(4,945)	9,890
Total operating expenses	$ 67,342	$ 43,448	$ 23,894	55 %
Operating expenses per Boe:				
Lease operating expense	$ 5.11	$ 3.51	$ 1.60	46 %
Production taxes	1.66	1.13	0.53	47
Gathering and transportation	1.40	1.75	(0.35)	(20)
Depreciation, depletion, amortization and accretion expense	16.94	18.27	(1.33)	(7)
Impairment of oil and natural gas properties	0.50	—	0.50	100
Exploration costs	0.82	0.58	0.24	41
General and administrative, excluding stock based compensation	5.72	4.51	1.21	27
Stock based compensation	0.58	—	0.58	100
Transaction expense	1.23	2.07	(0.84)	(41)
Gain on sale of property and equipment	(2.34)	(0.04)	(2.30)	5,750
Total operating expenses per Boe	$ 31.62	$ 31.78	$ (0.16)	(1)%

Lease operating expense ("LOE"). LOE increased by $6.1 million, or 127%. The increase in LOE is primarily due to increases in water disposal costs of $3.0 million, surface and production equipment rentals of $2.1 million, ad valorem taxes and company overhead of $0.5 million, and injection of water and gas costs of $0.5 million. These increases were primarily due to increased production, which is largely attributable to the new wells we added in 2017.

Production taxes. Production taxes increased by $2.0 million, or 129%. Production taxes are primarily based on the market value of our wellhead production. The increase was primarily due to increased total revenues. Our total revenues increased by 120% and production taxes increased by 129%. Production taxes as a percentage of total revenues were approximately 4.6% and 4.5% as of December 31, 2017 and 2016, respectively.

Gathering and transportation. Gathering and transportation expense increased by $0.6 million, or 24%. Gathering and transportation expenses increased primarily due to the increase in production volumes.

Depreciation, depletion, amortization and accretion expense ("DD&A"). DD&A increased by $11.1 million, or 45%. See the following table for a breakdown of DD&A:

	Year Ended December 31,		
	2017	2016	Change
Components of DD&A	(In thousands)		
Depreciation, depletion, amortization of oil and gas properties	$ 35,414	$ 24,432	$ 10,982
Depreciation of other property and equipment	360	357	3
Accretion expense	317	176	141
	$ 36,091	$ 24,965	$ 11,126
DD&A per MBoe			
Depreciation, depletion, amortization of oil and gas properties	$ 16.62	$ 17.88	$ (1.26)
Depreciation of other property and equipment	0.17	0.26	(0.09)
Accretion expense	0.15	0.13	0.02
Total DD&A per MBoe	$ 16.94	$ 18.27	$ (1.33)

DD&A for oil and gas properties increased by approximately $11.0 million due to an increase of approximately $13.7 million related to an increase in production partially offset by approximately $2.7 million due to a decrease in DD&A rate. The reduction in the DD&A rate was primarily due to additions to proved reserves and proved developed reserves over the past 12 months at a higher rate than additions to drilling and completion costs being capitalized over that time period.

Impairment of oil and natural gas properties. Impairment for 2017 primarily relates to the write-down of our remaining proved property located in the Barnett Shale that was not included in the disposition of the Barnett Shale Asset Sale.

Exploration costs. Exploration costs increased by $1.0 million, or 120%. The increase in exploration costs was primarily due to increased geology and geophysics studies in the Permian Basin along with increased land title work. Our exploration costs did not contain any dry hole costs for the year ended December 31, 2017.

General and administrative ("G&A"), excluding stock based compensation. G&A expense increased by $6.0 million, or 98%. The increase to G&A expense was primarily due to an increase in payroll and payroll related costs of approximately $3.3 million. Also, there was an increase of approximately $1.3 million for public company expenses such as board of director fees and expenses, public relations costs, filing fees, audit fees, and legal fees. Furthermore, the company incurred an increase of approximately $1.2 million for consultants to assist with various corporate functions such as accounting and human resources. These expenses were not incurred at the same levels, or at all, in periods prior to the Transaction.

Stock based compensation. Stock based compensation increased by $1.2 million for 2017 compared to 2016. In April 2017, the stockholders approved the Rosehill Resources Inc. Long-Term Incentive Plan and grants were made in 2017. There was no stock based compensation plan in 2016.

Transaction expense. Transaction expense decreased by $0.2 million, or 8%. Transaction expenses incurred for the years ended December 31, 2017 and 2016 are related to the Transaction. We do not expect to incur such transaction expense from our normal operations going forward.

Gain on sale of property and equipment. Gain on sale of property and equipment primarily relates to the disposition of the Barnett Shale assets. On November 2, 2017, we consummated the Barnett Shale Asset Sale for a purchase price of approximately $7.1 million. After customary purchase price adjustments, the net purchase price was approximately $6.5 million. The net book value of the Barnett Shales assets on the date of divestiture was $1.2 million, which resulted in a gain on sale of $5.3 million. The increase was partially offset by $0.3 million in losses upon asset retirement obligation settlements.

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

	Year Ended December 31,			
	2017	2016	Change	Change %
Other income (expense) *(in thousands):*				
Interest expense, net	$ (2,532)	$ (1,822)	$ (710)	39%
Gain (loss) on commodity derivatives, net	(16,336)	(4,169)	(12,167)	292
Other income (expense), net	(284)	(247)	(37)	15
Total other income (expense)	$ (19,152)	$ (6,238)	$ (12,914)	207%

Interest expense, net. Interest expense increased by $0.7 million, or 39%. The increase was primarily due to interest incurred on the issuance of $100 million aggregate principal amount of 10.00% Senior Secured Second Lien Notes issued on December 8, 2017.

Loss on commodity derivatives, net. Loss on commodity derivatives increased by $12.2 million, or 292%. Net losses on our commodity derivatives are a function of fluctuations in the underlying commodity prices versus fixed hedge prices and the monthly settlement of the instruments. The total net loss for 2017 is comprised of net gains of $0.2 million on cash settlements and net losses of $16.5 million on mark-to-market adjustments on unsettled positions. The net loss for 2016 is comprised of net losses of $0.9 million on cash settlements and net losses of $3.3 million on marked-to-market adjustments on unsettled positions.

Year ended December 31, 2016 compared to year ended December 31, 2015

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

	Year Ended December 31,			
	2016	2015	Change	Change %
Revenues *(In thousands):*				
Oil sales	$ 24,807	$ 20,601	$ 4,206	20 %
Natural gas sales	5,304	4,909	395	8
NGL sales	4,534	3,977	557	14
Total revenues	$ 34,645	$ 29,487	$ 5,158	17 %
Average realized prices before effect of derivatives:				
Oil (per Bbl)	$ 40.52	$ 43.62	$ (3.10)	(7)%
Natural gas (per Mcf)	2.23	2.37	(0.14)	(6)
Natural gas liquids (per Bbl)	12.68	12.75	(0.07)	(1)
Average realized price (per Boe)	$ 25.35	$ 26.09	$ (0.74)	(3)%
Average price after effect of settled derivatives (per Boe)	$ 22.30	$ 29.40	$ (7.10)	(24)%
Net Production:				
Oil (MBbls)	612	472	140	30 %
Natural gas (MMcf)	2,381	2,074	307	15
NGL (MBbls)	358	312	46	15
Total (MBoe)	1,367	1,130	237	21 %
Average daily net production volume:				
Oil (Bbls/d)	1,673	1,294	379	29 %
Natural gas (Mcf/d)	6,506	5,683	823	14
NGL (Bbls/d)	977	855	122	14
Total (Boe/d)	3,734	3,096	638	21 %

As reflected in the table above, our total revenues for 2016 were 17% higher, or $5.2 million, as compared to 2015. Oil sales for 2016 as compared to 2015 increased 20%, or $4.2 million, primarily due to a 30% increase in oil production (140 MBbls), or $5.7 million, offset by a 7% decrease in the average realized price for oil ($3.10 per Bbl), or $1.5 million. Natural gas sales for 2016 as compared to 2015 increased 8%, or $0.4 million, primarily due to a 15% increase in natural gas production (307 MMcf), or $0.7 million, offset by a 6% decrease in the average realized price for natural gas ($0.14 per Mcf), or $0.3 million. NGL sales for 2016 as compared to 2015 increased 14%, or $0.6 million, primarily due to a 15% increase in NGL production (46 MBbls), or $0.6 million.

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 operating expenses for the periods indicated:

	Year Ended December 31,			
	2016	2015	Change	Change %
Operating expenses *(in thousands):*				
Lease operating expense	$ 4,800	$ 4,582	$ 218	5 %
Production taxes	1,541	1,311	230	18
Gathering and transportation	2,398	2,094	304	15
Depreciation, depletion, amortization and accretion	24,965	23,364	1,601	7
Impairment of oil and natural gas properties	—	8,131	(8,131)	(100)
Exploration costs	794	960	(166)	(17)
General and administrative	6,166	4,234	1,932	46
Transaction costs	2,834	—	2,834	100
(Gain) loss on sale of property and equipment	(50)	18	(68)	(378)
Total operating expenses	$ 43,448	$ 44,694	$ (1,246)	(3)%
Operating expenses per Boe:				
Lease operating expense	$ 3.51	$ 4.06	$ (0.55)	(14)%
Production taxes	1.13	1.16	(0.03)	(3)
Gathering and transportation	1.75	1.85	(0.10)	(5)
Depreciation, depletion, amortization and accretion expense	18.27	20.68	(2.41)	(12)
Impairment of oil and natural gas properties	—	7.20	(7.20)	(100)
Exploration costs	0.58	0.85	(0.27)	(32)
General and administrative	4.51	3.75	0.76	20
Transaction expense	2.07	—	2.07	100
(Gain) loss on sale of property and equipment	(0.04)	0.02	(0.06)	(300)
Total operating expenses per Boe	$ 31.78	$ 39.57	$ (7.79)	(20)%

Lease operating expense. LOE increased 5%, or $0.2 million, in 2016 as compared to 2015. The increase was due to purchases of injection water and gas of $0.2 million. On a Boe basis, LOE decreased 14%, or $1.0 million, primarily due to a 237 MBoe increase in production during 2016 compared to 2015.

Production taxes. Production taxes are primarily based on the market value of our production at the wellhead. Production taxes increased 18%, or $0.2 million, in 2016 as compared to 2015 due to an increase of $5.2 million in production revenues in 2016 as compared to 2015. On a Boe basis, production taxes decreased 3%, or $0.03 per Boe, primarily due to higher production volumes (237 MBoe) in 2016 as compared to 2015. Production taxes as a percentage of our revenue was 5% for 2016 compared to 4% for 2015.

Gathering and transportation expense. Gathering and transportation expenses increased 15%, or $0.3 million, during 2016 as compared to 2015 due to a 237 MBoe increase in sales and processing volumes. On a Boe basis, gathering and transportation expenses decreased 5%, or $0.10 per Boe, due to higher sales and processing volumes (237 MBoe) during 2016 compared to 2015.

Depreciation, depletion, amortization and accretion. Our DD&A rate can fluctuate as a result of impairments, dispositions, exploration and development costs, and proved reserve volumes. DD&A increased 7%, or $1.6 million, during the year ended December 31, 2016 compared to the prior year, due to higher production volumes in 2016 (237 MBoe), or $4.3 million, offset by a lower DD&A rate of $2.8 million. The DD&A rate on a Boe basis decreased 12%, or $1.8 million ($2.41 per Boe), due to the increases in proved developed reserves during 2016 (767 MBoe).

Impairment of oil and gas properties. We did not record any impairment in 2016. In 2015, we recorded an $8.1 million impairment expense, all of which was attributable to an impairment of developed properties.

Exploration costs. Exploration costs decreased 17%, or $0.2 million, due to a reduction in contract personnel during the year ended December 31, 2016 compared to the prior year. On a Boe basis, exploration costs decreased 32%, or $0.27 per Boe.

General and administrative. G&A expense increased 46%, or $1.9 million, primarily due to an increase in salaries and benefits ($1.4 million) and legal expense ($0.3 million). On a Boe basis, G&A expense increased 20%, or $0.76 per Boe.

Transaction expenses. Transaction expenses of $2.8 million related to the Transaction were incurred during the year ended December 31, 2016.

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

	Year Ended December 31,			
	2016	**2015**	**Change**	**Change %**
Other income (expense) *(in thousands):*				
Interest expense, net	$ (1,822)	$ (3,247)	$ 1,425	(44)%
Gain (loss) on commodity derivatives, net	(4,169)	3,735	(7,904)	(212)
Other income (expense), net	(247)	7	(254)	(3,629)
Total other income (expense)	$ (6,238)	$ 495	$ (6,733)	(1,360)%

Interest expense, net. Interest expense, net decreased 44%, or $1.4 million, due to a decrease in the average borrowings under our secured line of credit during the year ended December 31, 2016 ($55.0 million) compared to the prior year ($65.0 million).

Gain (loss) on commodity derivatives, net. The decrease was primarily due to a 212%, or $7.9 million, decrease in gain (loss) on commodity derivatives, net. The decrease in commodity prices that resulted in a 3% decrease in the average realized price per Boe, or $1.8 million ($0.74 per Boe), was offset by a 21% increase in average net daily production, or $6.9 million (237 MBoe), as compared to the prior year. The increase in average net daily production was attributable to four operated and one non-operated new wells coming on line during the year ended December 31, 2016.

During 2016, we recognized a $4.2 million commodity derivative loss as compared to a $3.7 million commodity derivative gain in 2015. Net gains and losses on our commodity derivatives are a function of fluctuations in the underlying commodity prices and the monthly settlement of the instruments.

Capital Requirements and Sources of Liquidity

Overview

Our development and acquisition activities require us to make significant operating and capital expenditures. Historically our primary sources of liquidity have been cash flows from operations, financing entered into in connection with the Transaction and the White Wolf Acquisition, proceeds from the sale of assets in the Barnett Shale and borrowings under our Credit Agreement. Our primary uses of cash have been for the acquisition and development of oil and natural gas properties, payments of operating and general and administrative costs, and interest payment on outstanding debt.

The following table summarizes our capital expenditures incurred during the year:

	Year Ended December 31, 2017
	(In thousands)
Well drilling and completion costs, excluding costs in progress at December 31, 2017	$ 179,303
Unproved leasehold acquisition costs, primarily White Wolf Acquisition	121,207
Well drilling and completion costs in progress at December 31, 2017	21,349
Facilities, disposal and water wells, and pipelines	20,709
Acquire additional working and royalty interest in Loving County	6,500
Additions to other property and equipment	575
Total capital expenditures incurred	$ 349,643

We expect our 2018 capital budget for drilling and completion activities and facilities costs to be in the range of $350 to $375 million. We anticipate that 80-85% of our 2018 capital budget will be incurred in connection with drilling and completion activities. We believe we have adequate liquidity to fund planned 2018 capital expenditures and to meet our near-term future obligations.

We expect to continue funding our short-term and long-term growth with cash on hand, cash flow from operations, availability under our Credit Agreement, the issuance of up to $50 million of additional Series B Preferred Stock and/or opportunistically accessing the capital markets. 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 operations, investing and financing activities, and our ability to assimilate acquisitions and execute our drilling program. We review our capital expenditure forecast periodically 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 execute on our drilling program.

Because we are the operator of a high percentage of our acreage, the timing and level of our capital spending is largely discretionary and within our control. We could choose to defer a portion of these planned 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, natural gas and NGLs, 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 "Description of 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 if such a deferral of planned capital expenditures means we will be unable to develop such reserves within five years of their initial booking.

In the event we make any acquisitions and the amount of capital required is greater than the amount we have available for acquisitions at that time, we could be required to reduce the expected level of capital expenditures and/or seek additional capital. If we require additional capital for that or other reasons, we may seek such capital through traditional reserve base borrowings, joint venture partnerships, production payment financings, asset sales, offerings of debt or equity securities, or other means.

At December 31, 2017, we were in compliance with the financial covenants in the Credit Agreement and other financing documents for the measurement period ended December 31, 2017. We plan to continue an active hedging program to reduce the impact of commodity price volatility on our cash flow from operations.

Working Capital Analysis

We define working capital as current assets less current liabilities. As of December 31, 2017, we had a working capital deficit of $60 million compared to a surplus of $2.1 million at December 31, 2016. The increase in our deficit was attributable to our increased drilling and completion activities in the Northern Delaware Basin. We may continue to incur working capital deficits in the future due to liabilities incurred in connection with our drilling program until revenue is recognized from the associated production. Collection of our accounts receivable has historically been timely, and losses associated with uncollectible receivables have historically not been significant. Cash and cash equivalents totaled $20.7 million and $8.4 million, at December 31, 2017 and December 31, 2016, respectively. The Company's borrowing base under its credit facility was $75 million, with no borrowings outstanding at December 31, 2017. We expect that the pace of development activities, production volumes, commodity prices, differentials to NYMEX prices for oil and natural gas production, and financing activities will be the most significant variables affecting our working capital.

Cash Flows from Operating, Investing and Financing Activities

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

	Year Ended December 31,		
	2017	**2016**	**2015**
Net cash provided by (used in)		(In thousands)	
Operating activities	$ 37,759	$ 11,461	$ 18,244
Investing activities	(265,497)	(22,164)	(16,993)
Financing activities	243,986	(8,597)	17,519
Net change in cash, cash equivalents, and restricted cash	$ 16,248	$ (19,300)	$ 18,770

Analysis of Cash Flow Changes for the Year Ended December 31, 2017 and 2016

Operating Activities. Net cash provided by operating activities is primarily driven by the changes in commodity prices, operating expenses, production volumes, and associated changes in working capital. The increase in net cash provided by operating activities of $26.3 million was primarily due to an increase in production and realized prices. Our total revenues increased by $41.6 million for the year ended December 31, 2017 compared to the year ended December 31, 2016. Although we reported a net loss for the year ended December 31, 2017, a significant amount of the loss was attributable to DD&A which is non-cash as well as a mark-to-market loss on unsettled commodity derivative instruments.

Investing Activities. Net cash used in investing activities is primarily comprised of acquisition and development of oil and natural gas properties. Net cash used in investing activities for the year ended December 31, 2017 primarily consisted of $114.8 million for the White Wolf Acquisition; $149.8 million for drilling and completion activities and facilities, which included $17.5 million for facilities, disposal and water wells, and pipelines and $12.1 million associated with drilling and completion cost in proress; $6.5 million to acquire additional interest in wells we operate in Loving County, and $0.6 million for other property and equipment. These amounts were partially offset by proceeds from our oil and natural gas properties dispositions of $6.3 million, which are primarily attributable to the net proceeds of $6.2 million from the Barnett Shale Asset Sale. In 2016, net cash used for investing activities included $22.0 million attributable to the acquisition and development of oil and natural gas properties.

Financing Activities. Net cash provided by financing activities increased by $252.6 million for the year ended December 31, 2017 compared to the year ended December 31, 2016. Net cash provided by financing activities for 2017 included net cash of $230.8 million from the issuance of the Series A Preferred Stock and the Series B Preferred Stock, $97.0 million of proceeds from the Second Lien Notes, and $18.7 million of proceeds from the Transaction. The cash provided by financing activity was partially offset by net cash payments on our revolving credit facility of $55 million, distribution to our noncontrolling interest in the amount of $40.5 million, debt issuance costs of $4.6 million, and distribution to the parent in the amount of $2.3 million. Net cash provided by financing activities in 2016 included $10.0 million of borrowings on Tema's secured line of credit, $20.0 million of repayments under Tema's secured line of credit and $1.4 million of parent investment.

Analysis of Cash Flow Changes for the Year Ended December 31, 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 decrease in net cash provided by operating activities of $6.8 million for the year ended December 31, 2016 as compared to the prior year was due to a decrease in net revenues, a decrease in accounts receivable ($3.9 million), and a decrease in prepaid and other current assets ($0.8 million), offset by an increase in accounts payable and accrued liabilities and other ($2.8 million), and an increase in net change in derivative instruments ($1.6 million).

Investing Activities. Net cash used in investing activities is primarily comprised of acquisition and development of oil and natural gas properties, net of dispositions. In 2016, net cash used for investing activities included $22.0 million attributable to the acquisition and development of oil and natural gas properties. In 2015, net cash used for investing activities included $17.2 million attributable to the acquisition and development of oil and natural gas properties.

Financing Activities. Net cash provided by financing activities in 2016 included $10.0 million of borrowings on Tema's secured line of credit, $20.0 million of repayments under Tema's secured line of credit and $1.4 million of parent investment. Net cash provided by financing activities in 2015 included $10.0 million of repayments under Tema's secured line of credit, $25.9 million of parent investment and $1.8 million of borrowings under a related party unsecured credit agreement.

Debt Agreements

Credit Agreement. On April 27, 2017, Rosehill Operating and PNC Bank, National Association, as lender, Administrative Agent and Issuing Bank, and each of the lenders from time to time party thereto (collectively, the "Lenders") entered into a credit agreement, as amended by the first amendment thereto, dated December 8, 2017 (the "Credit Agreement"), which provides Rosehill Operating with a revolving line of credit and a letter of credit facility of up to $250 million, subject to a borrowing base that is determined semi-annually by the Lenders based upon Rosehill Operating's financial statements and the estimated value of its oil and gas properties, in accordance with the Lenders' customary practices for oil and gas loans. Such redetermined borrowing base will become effective and applicable to Rosehill Operating and the Lenders on or about April 1st and October 1st of each year, as applicable, commencing October 1, 2017. Rosehill Operating and the Lenders may each request an additional redetermination of the borrowing base once between two successive scheduled redeterminations. The borrowing base will be automatically reduced upon the issuance or incurrence of debt under senior unsecured notes or upon Rosehill Operating's or any of its subsidiary's disposition of properties or liquidation of hedges in excess of certain thresholds. Amounts borrowed under the Credit Agreement may not exceed the borrowing base.

The initial borrowing base was $55 million, which may be increased with the consent of all lenders. The borrowing base increased to $75 million on October 30, 2017. The full amount of the borrowing base was available as of December 31, 2017. The Credit Agreement does not permit Rosehill Operating to borrow funds if at the time of such borrowing Rosehill Operating is not in pro forma compliance with the financial covenants. Additionally, Rosehill Operating's borrowing base may be reduced in connection with the subsequent redetermination of the borrowing base. The amounts outstanding under the Credit Agreement are secured by first priority liens on substantially all of Rosehill Operating's oil and natural gas properties and associated assets and all of the stock of Rosehill Operating's material operating subsidiaries that are guarantors of the Credit Agreement. If an event of default occurs under the Credit Agreement, the Lenders have the right to proceed against the pledged capital stock and take control of substantially all of Rosehill Operating and Rosehill Operating's material operating subsidiaries that are guarantors' assets.

Borrowings under the Credit Agreement will bear interest at a base rate plus an applicable margin ranging from 1.00% to 2.00% or at LIBOR plus an applicable margin ranging from 2.00% to 3.00%. The Credit Agreement matures on April 27, 2022. There was no amount outstanding at December 31, 2017 under the Credit Agreement.

The Credit Agreement contains various affirmative and negative covenants. These covenants may limit Rosehill Operating's ability to, among other things:

- incur additional indebtedness,
- make loans to others,
- make investments,
- enter into mergers,
- make or declare dividends or distributions,
- enter into commodity hedges exceeding a specified percentage of Rosehill Operating's expected production,
- enter into interest rate hedges exceeding a specified percentage of Rosehill Operating's outstanding indebtedness,
- incur liens,
- sell assets, and
- engage in certain other transactions without the prior consent of the Lenders.

The Credit Agreement also requires Rosehill Operating to maintain the following financial ratios:

- a working capital ratio, which is the ratio of consolidated current assets (including unused commitments under the Credit Agreement, but excluding non-cash assets) to consolidated current liabilities (excluding non-cash obligations, reclamation obligations to the extent classified as current liabilities and current maturities under the Credit Agreement), of not less than 1.0 to 1.0, and
- a leverage ratio, which is the ratio of the sum of all of Rosehill Operating's Total Funded Debt to EBITDAX (as such terms are defined in the Credit Agreement) for the four fiscal quarters then ended, of not greater than 4.00 to 1.00.

We were in compliance with the financial covenants in the Credit Agreement for the measurement period ended December 31, 2017.

On March 28, 2018, we entered into an Amended and Restated Credit Agreement (the "New Credit Agreement") by and among us, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and certain other financial institutions party thereto, as lenders. The New Credit Agreement amends and restates in its entirety the original Credit Agreement entered into on April 27, 2017 and amended on December 8, 2017. Pursuant to the New Credit Agreement, the lenders party thereto have agreed to provide us with a $500 million secured reserve-based revolving credit facility with a current borrowing base of $150 million. The maturity date of the New Credit Agreement is August 31, 2022 and automatically extended to March 2023 upon the payment in full of the Second Lien Notes. The borrowing base will be redetermined semi-annually, with the lenders and us each having the right to one interim unscheduled redetermination between any two consecutive semi-annual redeterminations. The first scheduled redetermination date is August 1, 2018 and then beginning in 2019 each April 1 and October 1 thereafter.

For additional information regarding our Credit Agreement, see Note 8 – *Long-term Debt -Revolving Credit Facility* in the Notes to the Consolidated Financial Statements under Item 8 of Part II of this Annual Report on Form 10-K.

Second Lien Notes. On December 8, 2017, Rosehill Operating issued and sold $100,000,000 in aggregate principal amount of 10.00% Senior Secured Second Lien Notes due January 31, 2023 (the “Second Lien Notes”) to EIG under and pursuant to the terms of that certain Note Purchase Agreement, dated as of December 8, 2017 (the “Note Purchase Agreement”), among Rosehill Operating and us, the holders of the Second Lien Notes party thereto (the “Holders”) and U.S. Bank National Association, as agent and collateral agent on behalf of the Holders (the “Agent”).

Under the Note Purchase Agreement, Rosehill Operating may, at its option, redeem the Second Lien Notes in whole or in part, together with accrued and unpaid interest thereon, (i) at any time after December 8, 2019 but on or prior to December 8, 2020, at a redemption price equal to 103% of the principal amount of the Second Lien Notes being redeemed, (ii) at any time after December 8, 2020 but on or prior to December 8, 2021, at a redemption price equal to 101.5% of the principal amount of the Second Lien Notes being redeemed and (iii) at any time after December 8, 2021, at a redemption price equal to the principal amount of the Second Lien Notes being redeemed. On or prior to December 8, 2019, Rosehill Operating may, at its option, redeem the Second Lien Notes in whole or in part, together with accrued and unpaid interest thereon, at a redemption price equal to 103% of the principal amount of the Second Lien Notes being redeemed plus an additional make-whole premium set forth in the Note Purchase Agreement.

The Second Lien Notes may become subject to redemption under certain other circumstances, including upon the incurrence of non-permitted debt or, subject to various exceptions, reinvestments rights and prepayment or redemption rights with respect to other debt or equity of Rosehill Operating, upon an asset sale, hedge termination or casualty event. Rosehill Operating will be further required to make an offer to redeem the Second Lien Notes upon a Change in Control (as defined in the Note Purchase Agreement) at a redemption price equal to 101% of the principal amount being redeemed. Other than in connection with a change in control or casualty event, the redemption prices and make-whole premium described in the foregoing paragraph shall also apply, at such times and to the extent set forth therein, to any mandatory redemption of the Second Lien Notes or any acceleration of the Second Lien Notes prior to the stated maturity thereof upon the occurrence of an event of default.

The Note Purchase Agreement requires Rosehill Operating to maintain a leverage ratio, which is the ratio of the sum of all of Rosehill Operating’s Total Funded Debt to EBITDAX (as such terms are defined in the Note Purchase Agreement) for the four fiscal quarters then ended, of not greater than 4.00 to 1.00.

The Note Purchase Agreement contains various affirmative and negative covenants. The negative covenants may limit Rosehill Operating’s ability to, among other things, incur additional indebtedness (including pursuant to senior unsecured notes), make investments, make or declare dividends or distributions, redeem its preferred equity, acquire or dispose of oil and gas properties and other assets or engage in certain other transactions without the prior consent of the Holders, subject to various exceptions, qualifications and value thresholds. Rosehill Operating is also required to meet minimum commodity hedging levels based on its expected production on an ongoing basis.

We are subject to certain limited restrictions under the Note Purchase Agreement, including (without limitation) a negative pledge with respect to our equity interests in Rosehill Operating and a contingent obligation to guarantee the Second Lien Notes upon request by the Holders in the event that we incur debt obligations.

The obligations of Rosehill Operating under the Note Purchase Agreement are secured on a second-lien basis by the same collateral that secures its first-lien obligations. In connection with the Notes Purchase Agreement, Rosehill Operating granted first-lien and second-lien security interests over additional collateral to meet the minimum mortgage requirements under the Note Purchase Agreement.

Preferred Stock and Warrants

We are authorized to issue up to 1,000,000 shares of our preferred stock, of which 150,000 have been designated as Series A Preferred Stock and 210,000 have been designated as Series B Preferred Stock. On April 27, 2017, we issued 75,000 shares of Series A Preferred Stock and 5,000,000 warrants (exercisable for shares of Class A Common Stock) in a private placement to certain qualified institutional buyers and accredited investors for net proceeds of $70.8 million. We issued an additional 20,000 shares of Series A Preferred Stock to Rosemore Holdings, Inc. and KLR Sponsor in connection with the closing of the Transaction. See “Note 1 - Organization and Basis of Presentation” in the Consolidated Financial Statements under Item 8 of Part II of this Annual Report on Form 10-K for additional information regarding our preferred stock and warrants issuance.

On December 8, 2017, in connection with the White Wolf Acquisition, see Note 3 - *Acquisitions and Divestitures*, we issued 150,000 shares of Series B Preferred Stock, par value of $0.0001 per share, to EIG (the "Series B Preferred Stock Purchasers) for an aggregate purchase price of $150.0 million, less transaction costs and up-front fees of approximately $10.0 million. The Company has the option, subject to certain conditions, to sell from time to time up to an additional 50,000 shares of Series B Preferred Stock, in the aggregate, to the Series B Preferred Stock Purchasers and their transferees for a purchase price of $1,000 per share of Series B Preferred Stock. Such option terminates on December 8, 2018.

Contractual Obligations

A summary of the Company's contractual obligations as of December 31, 2017 is provided in the following table:

	2018	2019	2020	2021	2022	Thereafter	Total
				(In thousands)			
Second Lien Notes (1)	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 10,000	$ 100,833	$ 150,833
Operating lease obligations	1,230	1,213	1,202	1,097	557	—	5,299
Capital lease obligations	34	34	3	—	—	—	71
Asset retirement obligations (2)	108	—	—	1,958	—	13,389	15,455
Series A Preferred Stock dividends (3)	7,869	8,518	—	—	—	—	16,387
Series B Preferred Stock dividends and return (4)	15,290	15,674	15,717	15,674	15,674	202,167	280,196
Drilling commitments (5)	11,709	—	—	—	—	—	11,709
Total	$ 46,240	$ 35,439	$ 26,922	$ 28,729	$ 26,231	$ 316,389	$ 479,950

(1) Includes both principal and interest

(2) Amounts represent estimates of our future asset retirement obligations. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology, and the political and regulatory environment.

(3) Does not include the effect of future redemptions or conversions, if any. We have the right to cause all or any portion of the outstanding shares of Series A Preferred Stock to be converted in Class A Common Stock on or after April 27, 2019; therefore, we assumed a conversion on April 27, 2019 which would no longer require us to pay dividends.

(4) Includes liquidation preference of $150.6 million outstanding as of December 31, 2017 plus the return necessary to achieve a 16% IRR. The holders of the Series B Preferred Stock may cause us to redeem all or a portion of the Series B Preferred Stock on or after December 8, 2023; therefore, we assumed a redemption on December 8, 2023.

(5) We had 2 drilling rigs under contracts as of December 31, 2017. Early termination of such contracts would have resulted in termination penalties of $4.9 million, which would have been payable as of December 31, 2017 in lieu of the remaining drilling commitments

under the contracts. These amounts only include daily drilling rates and not costs such as reimbursement of fees that we may incur from the contractor.

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, 2017, 2016 and 2015. Although the impact of inflation has been insignificant in recent years, it is still a factor in the United States economy, and in the past, we have tended to experience inflationary pressure on the cost of midstream and oilfield services and equipment as increasing oil and natural gas prices increased drilling activity in our areas of operations. We expect service costs to increase in 2018 due to higher demand resulting from the recent improvement in oil prices.

Off-Balance Sheet Arrangements

As of December 31, 2017, we had no off-balance sheet arrangements.

Recently Issued Accounting Pronouncements

Please refer to Note 2— *Summary of Significant Accounting Policies and Recently Issued Accounting Standards* in the Consolidated Financial Statements under Item 8 of Part II of this Annual Report on Form 10-K for a discussion of recent accounting pronouncements and their anticipated effect on us.

Critical Accounting Policies

Successful Efforts Method of Accounting for Oil and Natural Gas Activities

Oil and natural gas exploration, development and production activities are accounted for under the successful efforts method of accounting. Under this method, the costs incurred to acquire, drill, and complete productive wells and development wells are capitalized. Oil and gas lease acquisition costs are also capitalized.

Proved Oil and Natural Gas Properties. If proved reserves are found for these properties, costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering, and storing oil, natural gas, and NGLs are capitalized. All costs incurred to drill and equip successful exploratory wells, development wells, development-type stratigraphic test wells, and service wells, including unsuccessful development wells, are capitalized. Capitalized costs attributed to the properties and mineral interests are subject to depreciation, depletion and amortization ("DD&A"). Depletion of capitalized costs is provided using the units-of-production method based on proved oil and gas reserves related to the associated reservoir. If no proved reserves have been found, the costs of each of the related exploratory wells are charged to expense.

Unproved Properties. Acquisition costs associated with the acquisition of non-producing leaseholds are recorded as unproved leasehold costs and capitalized as incurred. These consist of costs incurred in obtaining a mineral interest or right in a property, such as a lease in addition to options to lease, broker fees, recording fees, and other similar costs related to acquiring properties. Leasehold costs are classified as unproved until proved reserves are discovered, at which time related costs are transferred to proved oil and natural gas properties.

Exploration Costs. Exploration costs, other than exploration drilling costs, are charged to expense as incurred. These costs include exploratory seismic expenditures, other geological and geophysical costs, and lease rentals. The costs of drilling exploratory wells and exploratory-type stratigraphic wells are initially capitalized 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.

In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. The costs of such exploratory wells are expensed if a determination of proved reserves has not been made within a 12-month period after drilling is complete.

For sales of a complete or partial unit of proved and unproved properties, and related facilities, the cost and related accumulated DD&A are removed from the property accounts and gain or loss is recognized for the difference between the proceeds received and the net carrying value of the properties sold.

Impairment of Oil and Natural Gas Properties

Our proved oil and natural gas properties are recorded at cost. Our proved properties are evaluated for impairment on a field-by-field basis whenever events or changes in circumstances indicate that an asset's carrying value may not be recoverable. We compare expected undiscounted future cash flows to the net book value of the asset. If the future undiscounted expected cash flows, based on its estimate of future oil and natural gas prices, operating costs and anticipated production from proved reserves and risk-adjusted probable and possible reserves, are lower than the net book value of the asset, the capitalized cost is reduced to fair value. Commodity pricing is estimated by using WTI and Henry Hub natural gas NYMEX strip market pricing, adjusted for quality, transportation fees and a regional price differential. While it is difficult to project future impairment write-downs in light of numerous factors involved, fluctuations in prices or costs could result in an impairment of our oil and natural gas properties.

Unproved oil and natural gas properties are assessed periodically, and no less than annually, for impairment on an aggregate basis based on remaining lease term, drilling results, reservoir performance, seismic interpretation and future plans to develop acreage. As unproved oil and natural gas properties are developed and reserves are proved, the capitalized costs are subject to depreciation and depletion. If the development of these properties is deemed unsuccessful, the capitalized costs related to the unsuccessful activity is expensed in the year the determination is made. The rate at which the unproved oil and natural gas properties are written off or reclassified to proved oil and natural gas properties depends on the timing and success of our future exploration and development program.

Depreciation, Depletion and Amortization for Oil and Gas Properties

The quantities of estimated proved oil and gas reserves are a significant component of our calculation of depreciation, depletion and amortization expense, and revisions in such estimates may alter the rate of future expense. Holding all other factors constant, if reserves were revised upward or downward, earnings would increase or decrease, respectively.

Depreciation, depletion and amortization of the cost of proved oil and gas properties is calculated using the unit-of-production method. The reserve base used to calculate depreciation, depletion and amortization for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. With respect to lease and well equipment costs, which include development costs and successful exploration drilling costs, the reserve base includes only proved developed reserves. Estimated future dismantlement, restoration and abandonment costs, net of salvage values, are taken into account.

Oil and gas properties are grouped based upon a reasonable aggregation of properties with a common geological structural feature or stratigraphic condition, such as a reservoir or field.

Depreciation, depletion and amortization rates are updated quarterly to reflect the addition of capital costs, reserve revisions (upwards or downwards) and additions, property acquisitions and/or property dispositions and impairments.

Oil and Natural Gas Reserve Quantities

Our estimated proved reserve quantities and future net cash flows are critical to the understanding of the value of our business. They are used in comparative financial ratios and are the basis for significant accounting estimates in its financial statements, including the calculations of depletion and impairment of proved oil and natural gas properties. Future cash inflows and future production and development costs are determined by applying prices and costs, including transportation, quality differentials, and basis differentials, applicable to each period to the estimated quantities of proved reserves remaining to be produced as of the end of that period. Expected cash flows are discounted to present value using an appropriate discount rate. For example, the standardized measure calculations require a 10% discount rate to be applied. Although reserve estimates are inherently imprecise, and estimates of new discoveries and undeveloped locations are more imprecise than those of established producing oil and gas properties, we make a considerable effort in estimating our reserves. We expect proved reserve estimates will change as additional information becomes available and as commodity prices and operating and capital costs change. We have and expect to evaluate and estimate our proved reserves each year-end. For purposes of depletion and impairment, reserve quantities are adjusted in accordance with U.S. GAAP for the impact of additions and dispositions.

Asset Retirement Obligations

An asset retirement obligation ("ARO") represents the estimated present value of the amount we will incur to retire a long-lived asset at the end of its productive life, in accordance with applicable state laws. We recognize an estimated liability for future costs primarily associated with the abandonment of our oil and natural gas properties and related assets. The amount of the ARO is determined by calculating the present value of estimated cash flows related to the liability. The retirement obligation is recorded as a liability at its estimated present value at inception (i.e., at the time the well is drilled or acquired and related assets are placed into service) with an offsetting increase in the carrying amount of the related long-lived asset that is included in proved oil and natural gas properties in the accompanying consolidated balance sheets. Periodic accretion of discount of the estimated liability is recorded as an expense in the income statement. We depreciate the long-lived asset, including the asset retirement cost, over its useful life and recognize an expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective oil and natural gas properties.

Asset retirement liability is determined using significant assumptions, including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive lives of assets, and our risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Because of the subjectivity of assumptions, the costs to ultimately retire our wells may vary significantly from prior estimates.

Commodity Derivative Instruments

We utilize commodity derivative instruments including swaps, collars, basis swaps, and other similar agreements to manage our exposure to oil and natural gas price volatility (i.e., price risk) associated with the forecasted sale of a portion of our oil and natural gas production. These commodity derivative instruments are not designated as hedges for accounting purposes. Accordingly, we record derivative instruments on the consolidated balance sheets as either an asset or liability measured at fair value and record the change in the fair value of derivatives in current earnings in the statements of operations as they occur in the period of change. Gains and losses on commodity derivatives and premiums paid for put options are included in cash flows from operating activities.

To the extent a legal right of offset exists with a counterparty, we report derivative assets and liabilities on a net basis. We have exposure to credit risk to the extent the counterparty is unable to satisfy its settlement obligation. We actively monitor the creditworthiness of counterparties and assesses the impact, if any, on our derivative position.

Beneficial Conversion Feature in the Series A Preferred Stock

The nondetachable conversion option embedded in the Series A Preferred Stock was evaluated to determine whether a beneficial conversion feature existed as of the closing date of the Transaction which would be recognized separately from the Series A Preferred Stock in our consolidated financial statements. The conversion option is considered beneficial if, at the commitment closing date, the effective conversion price (represented by the proceeds received less the allocated value of the warrants and Class A Common Stock) for the Series A Preferred Stock is less than the fair value of the Class A Common Stock into which it is convertible at the commitment closing date. As a result of this evaluation, we separately recognized in equity, with an offsetting reduction in the carrying amount of the Series A Preferred Stock, the value of the beneficial conversion feature at the commitment date of $6.7 million. Since our Series A Preferred Stock is perpetual and has no stated maturity date and no restrictions on conversion, the value attributable to the nondetachable conversion option was recognized immediately as a non-cash deemed dividend on the date that the Series A Preferred Stock was issued.

Future issuances of Series A Preferred Stock resulting from dividends paid-in-kind may, depending on the trading price per share of our Class A Common Stock on the dividend date, contain a beneficial conversion option determined on the same basis as described above and, thus, result in additional non-cash deemed dividends which will reduce net income attributable to our stockholders when such paid-in-kind preferred shares are granted.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES 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 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 occur in the future. The prices we receive for oil, natural gas, and NGLs production depend on numerous factors beyond our control, some of which are discussed under "Risk Factors - Risks Related to our Operations - *Oil, natural gas and NGL prices are volatile*" in Item 7A of Part I. A 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."

To achieve a more predictable cash flow and reduce exposure to adverse fluctuations in commodity prices, we have historically used commodity derivative instruments, such as swaps, two-way costless collars, and three-way costless collars, to hedge price risk associated with a portion of our anticipated oil and natural gas production. By removing a significant portion of the price volatility associated with our oil and natural gas production, we mitigate, but do not eliminate, the potential negative effects of declines in benchmark oil and natural gas prices on our cash flow from operations for those periods. We are under no obligation to hedge a specific portion of our production. See more information on our derivative activity in Item 7 of Part II, specifically the information set forth under the caption *"Derivative Activity"*.

Counterparty Exposure and Customer Credit Risk

Our commodity derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require counterparties to our commodity derivative contracts to post collateral, we do evaluate the credit standing of such counterparties as we deem appropriate. The counterparty to our commodity derivative contracts currently in place, all of which will either be transferred to us or settled in connection with the closing of the Transaction, 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 its 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. However, the credit quality of our customers is believed to be high.

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.

Our hedging policy permits us to enter into derivative contracts with major financial institutions or major energy entities. Our derivative contracts are currently with major financial institutions as lenders under our Credit Agreement. We have rights of offset against the borrowings under our Credit Agreement.

Interest Rate Risk

As of December 31, 2017, we had no borrowings outstanding under the Credit Agreement. Interest under the Credit Agreement is tiered based on amount borrowed. The interest rate is base rate (4.5% at December 31, 2017) plus an applicable margin ranging from 1.00% to 2.00% or LIBOR (1.4% at December 31, 2017) plus a range of 2% to 3% depending on the outstanding balance. 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 not materially impact our interest cost. We currently have no derivative arrangements to protect against fluctuations in interest rates applicable to our outstanding indebtedness.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Index to Consolidated Financial Statements

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Stockholders of
Rosehill Resources, Inc.
Houston, Texas

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Rosehill Resources, Inc. (the "Company") and its subsidiary as of December 31, 2017 and 2016, the related consolidated statements of operations, stockholders' equity/parent net investment, and cash flows for each of the three years in the period ended December 31, 2017, and the related notes (collectively referred to as the "consolidated financial statements"). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company and its subsidiary at December 31, 2017 and 2016, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2017, in conformity with accounting principles generally accepted in the United States of America.

Basis for Opinion

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

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

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

/s/ BDO USA, LLP

We have served as the Company's auditor since 2016.

Houston, Texas
April 17, 2018

ROSEHILL RESOURCES INC.
CONSOLIDATED BALANCE SHEETS
(In thousands, except share and per share amounts)

	December 31, 2017	December 31, 2016
ASSETS		
Current assets:		
Cash and cash equivalents	$ 20,677	$ 8,434
Restricted cash	4,005	—
Accounts receivable	1,527	1,928
Accounts receivable, related parties	16,022	4,837
Derivative assets	—	247
Prepaid and other current assets	1,312	897
Total current assets	43,543	16,343
Property and equipment:		
Oil and natural gas properties (successful efforts), net	431,332	122,267
Other property and equipment, net	1,283	1,106
Total property and equipment, net	432,615	123,373
Other assets, net	824	110
Total assets	$ 476,982	$ 139,826
LIABILITIES, MEZZANINE EQUITY AND STOCKHOLDERS' EQUITY / PARENT NET INVESTMENT		
Current liabilities:		
Accounts payable	$ 31,868	$ 4,658
Accounts payable, related parties	223	612
Derivative liabilities	10,772	1,856
Accrued liabilities and other	15,492	4,654
Accrued capital expenditures	45,045	2,443
Total current liabilities	103,400	14,223
Long-term liabilities:		
Long term debt, net	93,199	55,000
Asset retirement obligations, net of current portion	8,522	5,180
Deferred tax liabilities	153	—
Derivative liabilities	8,008	—
Other	168	203
Total long-term liabilities	110,050	60,383
Total liabilities	213,450	74,606
Commitments and contingencies (Note 16)		
Mezzanine equity		
Series B Preferred Stock, $0.0001 par value, 10.0% Redeemable, $1,000 per share liquidation preference; of the 1,000,000 shares of Preferred Stock authorized, 210,000 shares designated, 150,626 shares issued and outstanding as of December 31, 2017	140,868	—
Stockholders' equity / parent net investment		
Series A Preferred Stock, $0.0001 par value, 8.0% Cumulative Perpetual Convertible, $1,000 per share liquidation preference; of the 1,000,000 shares of Preferred Stock authorized, 150,000 shares designated, 97,698 shares issued and outstanding as of December 31, 2017	80,660	—
Class A Common Stock; $0.0001 par value, 95,000,000 shares authorized, 6,222,299 issued and outstanding as of December 31, 2017	1	—
Class B Common Stock; $0.0001 par value, 30,000,000 shares authorized, 29,807,692 issued and outstanding as of December 31, 2017	3	—
Additional paid-in capital	29,946	—
Retained earnings (deficit)	—	—
Total common stockholders' equity	29,950	—
Noncontrolling interest	12,054	—
Parent net investment	—	65,220
Total stockholders' equity / parent net investment	122,664	65,220
Total liabilities, mezzanine equity and stockholders' equity / parent net investment	$ 476,982	$ 139,826

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

ROSEHILL RESOURCES INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share amounts)

	Year Ended December 31,		
	2017	2016	2015
Revenues:			
Oil sales	$ 61,596	$ 24,807	$ 20,601
Natural gas sales	7,171	5,304	4,909
Natural gas liquids sales	7,469	4,534	3,977
Total revenues	76,236	34,645	29,487
Operating expenses:			
Lease operating expense	10,881	4,800	4,582
Production taxes	3,535	1,541	1,311
Gathering and transportation	2,976	2,398	2,094
Depreciation, depletion, amortization and accretion	36,091	24,965	23,364
Impairment of oil and natural gas properties	1,061	—	8,131
Exploration costs	1,747	794	960
General and administrative	13,428	6,166	4,234
Transaction costs	2,618	2,834	—
(Gain) loss on sale of property and equipment	(4,995)	(50)	18
Total operating expenses	67,342	43,448	44,694
Operating income (loss)	8,894	(8,803)	(15,207)
Other income (expense):			
Interest expense, net	(2,532)	(1,822)	(3,247)
Gain (loss) on commodity derivatives, net	(16,336)	(4,169)	3,735
Other income (expense), net	(284)	(247)	7
Total other income (expense)	(19,152)	(6,238)	495
Loss before income taxes	(10,258)	(15,041)	(14,712)
Income tax expense	1,690	148	108
Net loss	(11,948)	(15,189)	(14,820)
Net loss attributable to noncontrolling interest	(18,811)	—	—
Net income (loss) attributable to Rosehill Resources Inc. before preferred stock dividends	6,863	(15,189)	(14,820)
Series A Preferred Stock dividends and deemed dividends	12,936	—	—
Series B Preferred Stock dividends, deemed dividends and return	2,447	—	—
Net loss attributable to Rosehill Resources Inc. common stockholders	$ (8,520)	$ (15,189)	$ (14,820)
Loss per common share:			
Basic and diluted	$ (1.43)	$ (2.59)	$ (2.53)
Weighted average common shares outstanding:			
Basic and diluted	5,945	5,857	5,857

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

ROSEHILL RESOURCES INC.
CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY / PARENT NET INVESTMENT
(In thousands, except share amounts)

	Preferred Stock Series A		Common Stock									
			Class A		Class B							
	Shares	Value	Shares	Value	Shares	Value	Additional Paid-in Capital	Retained Earnings	Total Common Stockholders' Equity	Noncontrolling Interest	Parent Net Investment	Total Equity
Balance at December 31, 2014	—	$ —	—	$ —	—	$ —	$ —	$ —	$ —	$ —	$ 56,178	$ 56,178
Net income (loss)	—	—	—	—	—	—	—	—	—	—	(14,820)	(14,820)
Contribution from Parent in exchange for note payable	—	—	—	—	—	—	—	—	—	—	11,750	11,750
Distribution (to) from Parent	—	—	—	—	—	—	—	—	—	—	25,869	25,869
Balance at December 31, 2015	—	$ —	—	$ —	—	$ —	$ —	$ —	$ —	$ —	$ 78,977	$ 78,977
Net income (loss)	—	—	—	—	—	—	—	—	—	—	(15,189)	(15,189)
Distribution (to) from Parent	—	—	—	—	—	—	—	—	—	—	1,432	1,432
Balance at December 31, 2016	—	$ —	—	$ —	—	$ —	$ —	$ —	$ —	$ —	$ 65,220	$ 65,220
Net distribution to parent	—	—	—	—	—	—	—	—	—	—	(2,267)	(2,267)
Net income (loss)	—	—	—	—	—	—	—	2,449	2,449	(18,811)	4,414	(11,948)
Effect of the Transaction:												
Issuance of preferred stock and warrants	95,000	70,594	—	—	—	—	20,186	—	20,186	—	—	90,780
Proceeds and shares obtained in the Transaction	—	—	5,856,581	1	29,807,692	3	7,447	—	7,451	78,604	(67,367)	18,688
Distribution to noncontrolling interest, net	—	—	—	—	—	—	—	—	—	(38,106)	—	(38,106)
Benefit from reversal of valuation allowance	—	—	—	—	—	—	1,537	—	1,537	—	—	1,537
Restricted shares granted to directors and employee service awards	—	—	119,456	—	—	—	—	—	—	—	—	—
Stock based compensation	—	—	—	—	—	—	1,245	—	1,245	—	—	1,245
Series A Preferred stock dividends	5,530	12,898	—	—	—	—	(10,487)	(2,449)	(12,936)	—	—	(38)
Series A Preferred stock conversions	(2,832)	(2,832)	246,262	—	—	—	2,832	—	2,832	—	—	—
Series B Preferred stock dividends, deemed dividends and return	—	—	—	—	—	—	(2,447)	—	(2,447)	—	—	(2,447)
Impact of transactions affecting noncontrolling interests	—	—	—	—	—	—	9,633	—	9,633	(9,633)	—	—
Balance at December 31, 2017	97,698	$ 80,660	6,222,299	$ 1	29,807,692	$ 3	$ 29,946	$ —	$ 29,950	$ 12,054	$ —	$ 122,664

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

ROSEHILL RESOURCES INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2017	**2016**	**2015**
Cash flows from operating activities:			
Net loss	$ (11,948)	$ (15,189)	$ (14,820)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Depreciation, depletion, amortization and accretion	36,091	24,965	23,364
Impairment of oil and gas properties	1,061	—	8,131
Deferred income taxes	1,690	—	—
Stock-based compensation	1,245	—	—
Gain on sale of oil and natural gas properties	(4,995)	(50)	18
(Gain) loss on commodity derivative instruments	16,336	4,169	(3,735)
(Gain) loss on interest rate swaps	370	461	1,842
Net settlement of commodity derivative instruments	217	(823)	4,470
Net cash paid in settlement of interest rate swaps	(143)	(785)	(1,165)
Amortization of debt discount and issuance costs	274	113	98
Settlement of asset retirement obligations	(840)	(53)	(10)
Changes in operating assets and liabilities:			
(Increase) decrease in accounts receivable, including related parties	(8,230)	(3,091)	550
(Increase) decrease in prepaid and other assets	(451)	53	634
Increase (decrease) in accounts payable and accrued liabilities and other	7,476	1,691	(1,133)
Increase (decrease) in accounts payable, related parties	(394)	—	—
Net cash provided by operating activities	37,759	11,461	18,244
Cash flows from investing activities:			
Additions to oil and natural gas properties	(149,832)	(22,004)	(17,176)
Acquisition of White Wolf, net of escrow	(114,843)	—	—
Acquisition of leasehold interests	(6,500)	—	—
Additions to other property and equipment	(574)	(263)	(167)
Proceeds from sale of properties and equipment	6,252	103	350
Net cash used in investing activities	(265,497)	(22,164)	(16,993)
Cash flows from financing activities:			
Proceeds from revolving credit facility	66,000	10,000	—
Repayment on revolving credit facility	(121,000)	—	—
Repayment of long-term debt	—	(20,000)	(10,000)
Proceeds from issuance of Series A Preferred Stock and Warrants, net	95,000	—	—
Series A Preferred Stock issuance costs	(4,220)	—	—
Proceeds from issuance of Series B Preferred Stock, net	150,000	—	—
Series B Preferred Stock upfront fees and transaction costs	(10,017)	—	—
Proceeds from Second lien notes, net	97,000	—	—
Net proceeds from the Transaction	18,688	—	—
Distribution to noncontrolling interest	(40,487)	—	—
Contribution (distribution) to parent	(2,267)	1,432	25,869
Proceeds from notes payable to related party	—	—	1,750
Debt issuance costs	(4,640)	—	(72)
Dividends paid on Series A Preferred stock	(38)	—	—
Payment on capital lease obligation	(33)	(29)	(28)
Net cash provided by (used in) financing activities	243,986	(8,597)	17,519
Net increase (decrease) in cash and cash equivalents	16,248	(19,300)	18,770
Cash, cash equivalents, and restricted cash, beginning of period	8,434	27,734	8,964
Cash, cash equivalents, and restricted cash, end of period	$ 24,682	$ 8,434	$ 27,734

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

ROSEHILL RESOURCES INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS (Continued)
(In thousands)

Supplemental cash flow information and noncash activity:

	Year Ended December 31,		
	2017	2016	2015
Supplemental cash flow information:			
Cash paid for interest	1,889	1,794	2,371
Supplemental noncash activity:			
Asset retirement obligations incurred	5,766	1,641	515
Contribution from Parent in exchange for note payable	—	—	11,750
Changes in accrued capital expenditures	42,602	(1,434)	1,090
Changes in accounts payable for capital expenditures	25,541	—	—
White Wolf Acquisition escrow deposit	4,005	—	—
Series A Preferred Stock dividends paid in kind	5,530	—	—
Series B Preferred Stock dividends paid in kind	626	—	—
Series B Preferred Stock cash dividends declared but not yet paid	937	—	—
Series B Preferred Stock return	710	—	—
Settlement due from Tema	2,381	—	—

Reconciliation of cash, cash equivalents and restricted cash presented on the Consolidated Statement of Cash Flows:

	Year Ended December 31,		
	2017	2016	2015
Cash and cash equivalents	$ 20,677	$ 8,434	$ 27,734
Restricted cash	4,005	—	—
Total cash, cash equivalents and restricted cash	$ 24,682	$ 8,434	$ 27,734

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

Note 1 – Organization and Basis of Presentation

Organization

Rosehill Resources Inc. (the "Company" or "Rosehill") is an independent oil and natural gas company focused on the acquisition, exploration, development and production of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin. At December 31, 2017, the Company's assets are concentrated in the Delaware Basin, a sub-basin of the Permian Basin.

The Company was incorporated in Delaware on September 21, 2015 as a special purpose acquisition company under the name of KLR Energy Acquisition Corp. ("KLRE") for the purpose of effecting a merger, capital stock exchange, asset acquisition, stock purchase, reorganization or similar business combination involving the Company and one or more businesses. On April 27, 2017, the Company acquired a portion of the equity of Rosehill Operating Company, LLC ("Rosehill Operating") via a reverse recapitalization (the "Transaction"), into which Tema Oil & Gas Company ("Tema"), a wholly owned subsidiary of Rosemore, Inc. ("Rosemore"), contributed certain assets and liabilities. At the closing of the Transaction, the Company became the sole managing member of Rosehill Operating. Following the Transaction, the Company changed its name to Rosehill Resources Inc.

As the sole managing member of Rosehill Operating, the Company, through its officers and directors, is responsible for all operational and administrative decision-making and control of all of the day-to-day business affairs of Rosehill Operating without the approval of any other member, unless specified in the Second Amended and Restated Limited Liability Company Agreement of Rosehill Operating (the "LLC Agreement").

Transaction

On April 27, 2017, upon closing the Transaction, the Company acquired a portion of the common units of Rosehill Operating for (i) the contribution to Rosehill Operating by the Company of $35 million in cash (the "Cash Consideration"), excluding the working capital adjustment, and for the issuance to Rosehill Operating by the Company of 29,807,692 shares of its Class B Common Stock, (ii) the assumption by Rosehill Operating of $55 million in Tema indebtedness and (iii) the contribution to Rosehill Operating by the Company of the remaining cash proceeds of the Company's initial public offering net of redemptions of approximately $60.6 million. In connection with the closing of the Transaction, the Company issued to Rosehill Operating 4,000,000 warrants exercisable for shares of Class A Common Stock (the "Tema warrants") in exchange for 4,000,000 warrants exercisable for Rosehill Operating Common Units (the "Rosehill warrants"). The Cash Consideration, estimated working capital adjustment, Tema warrants and shares of Class B Common Stock were immediately distributed to Tema. The working capital adjustment was originally estimated to be $5.6 million and was contributed to Rosehill Operating by the Company upon closing the Transaction. The final working capital adjustment of $2.4 million due to the Company from Tema was reflected as a reduction to the preliminary purchase price as of December 31, 2017.

In connection with the Transaction, the Company issued and sold 75,000 shares of its 8% Series A Cumulative Perpetual Convertible Preferred Stock (the "Series A Preferred Stock") and 5,000,000 warrants in a private placement to certain qualified institutional buyers and accredited investors (the "PIPE Investors") for net proceeds of $70.8 million (the "PIPE Investment"). The Company issued an additional 20,000 shares of Series A Preferred Stock to Rosemore Holdings, Inc. (wholly owned subsidiary of Rosemore) and KLR Energy Sponsor, LLC (the "KLR Sponsor") in connection with the closing of the Transaction for net proceeds of $20 million. The Company contributed the net proceeds from the PIPE Investment and from the issuance of 20,000 shares of Series A preferred stock to Rosemore Holdings, Inc. and KLR Sponsor to Rosehill Operating in exchange for Rosehill Operating Series A preferred units and additional Rosehill warrants. Of these proceeds, $55 million was used to retire the indebtedness assumed by Rosehill Operating.

Net cash provided by the Company upon the closing of the Transaction was $109.5 million, which consisted of $90.8 million of net proceeds from the sale of Series A Preferred Stock and $18.7 million from the sale of common shares prior to the Transaction, net of redemptions and offering and transaction costs.

Basis of Presentation

The consolidated financial results of the Company consist of the financial results of Rosehill Resources Inc. and Rosehill Operating, its consolidated subsidiary. Pursuant to the Transaction described above, the Company acquired approximately 16% of the Rosehill Operating Common Units, while Tema retained approximately 84% of the Rosehill Operating Common Units.

The Transaction was structured as a reverse recapitalization. The historical operations of Rosehill Operating are deemed to be those of the Company. Thus, the financial statements included in this report reflect (i) the historical operating results of Rosehill Operating prior to the Transaction; (ii) the consolidated results of the Company and Rosehill Operating following the Transaction; (iii) the assets and liabilities of Rosehill Operating at their historical cost; and (iv) the Company's equity and earnings per share for all periods presented.

All periods prior to the date of the Transaction shown in the accompanying consolidated financial statements have been prepared on a "carve-out" basis and are derived from the accounting records of Tema. The accompanying consolidated financial statements prior to the Transaction include direct expenses related to Rosehill Operating and expense allocations for certain functions of Tema including, but not limited to, general corporate expenses related to finance, legal, information technology, human resources, communications, insurance, utilities, and compensation. These expenses have been allocated on the basis of direct usage when identifiable, actual volumes and revenues, with the remainder allocated proportionately on a barrel of oil equivalent ("Boe") basis. Management considers the basis on which the expenses have been allocated to reasonably reflect the utilization of services provided to or the benefit received by Rosehill Operating during the periods presented. The allocations may not, however, reflect the expenses that would have been incurred as an independent company for the periods presented. Actual costs that may have been incurred prior to the Transaction would depend on a number of factors, including the organizational structure, whether functions were outsourced or performed by employees and strategic decisions made in areas such as information technology and infrastructure. The allocations and related estimates and assumptions are described more fully in Note 15 – *Related Party Transactions.*

The financial statements have been prepared pursuant to the rules and regulations of the Securities and Exchange Commission ("SEC") and in accordance with generally accepted accounting principles in the United States ("U.S. GAAP").

Note 2 – Summary of Significant Accounting Policies

Use of Estimates

The preparation of the Company's consolidated financial statements requires the Company's management to make various assumptions, judgments and estimates to determine the reported amounts of assets, liabilities, revenues and expense, 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 and, accordingly, actual results could differ from amounts previously reported. The more significant areas requiring the use of assumptions, judgments and estimates include:

- the quantities and values of proved oil, natural gas and natural gas liquids ("NGLs") reserves used in calculating depletion and assessing impairment of oil and natural gas properties and related present value estimates of future net cash flows therefrom,
- the carrying value of oil and natural gas properties,
- impairment of oil and natural gas properties,

- asset retirement obligations,
- oil and natural gas reserve quantities,
- the fair value of commodity derivative instruments and positions,
- fair value of the Company's warrants,
- estimates of the fair value of equity-based compensation,
- estimates of current and deferred income taxes, and
- deferred income tax valuation allowances and amounts associated with the Company's Tax Receivable Agreement with Tema (the "Tax Receivable Agreement") (see Note 13 – *Income Taxes)*.

While management believes these estimates are reasonable, changes in facts and assumptions, or the discovery of new information may result in revised estimates. Actual results could differ from these estimates and it is reasonably possible these estimates could be revised in the near term, and these revisions could be material.

Reclassifications

Certain reclassifications have been made to prior year financial statements to conform to classifications made in the current year. These reclassifications have no impact on net income (loss), stockholders' equity or cash flows as previously presented.

Variable Interest Entities

Rosehill Operating is a variable interest entity ("VIE"). The Company determined that it is the primary beneficiary of Rosehill Operating as the Company is the sole managing member and has the power to direct the activities most significant to Rosehill Operating's economic performance as well as the obligation to absorb losses and receive benefits that are potentially significant. At December 31, 2017, the Company had an economic interest of approximately 17% in Rosehill Operating and consolidated 100% of Rosehill Operating's assets and liabilities and results of operations in the Company's consolidated financial statements. At December 31, 2017, Tema had an ownership interest of approximately 83% in Rosehill Operating; however, because it has disproportionately fewer voting rights, Tema is shown as a noncontrolling interest holder of Rosehill Operating. For further discussion, see *Noncontrolling Interest* in Note 11 - *Stockholders' Equity / Parent Net Investment.*

Cash and Cash Equivalents

The Company considers all cash on hand, and highly liquid instruments with an original maturity of three months or less to be cash and cash equivalents. The Company's cash and cash equivalents are held in financial institutions in amounts that may exceed the insurance limits of the Federal Deposit Insurance Corporation, however, management believes the Company's counter-party risks are minimal based on the reputation and history of the institutions selected.

Restricted Cash

In connection with the Company's initial closing of the White Wolf Acquisition in December 2017, see Note 3 - *Acquisitions and Divestitures*, the Company placed $4.0 million in an escrow account with an escrow agent to provide indemnification for any liabilities it may incur or sustain arising from third party claims against the seller. At the Company's option, the amount in escrow may be used to satisfy any such liability that arises within ninety (90) days following the closing date. Any remaining amounts within the escrow account will be released to the sellers, less the aggregate amount of all unsatisfied claims for indemnification that the Company makes.

Accounts Receivable

Accounts receivable consist of receivables from joint interest owners on properties the Company operates and from sales of oil and natural gas production delivered to purchasers. The purchasers remit payment for production directly to the Company. Most payments are received within three months after the production date. Accounts receivable are not collateralized.

Amounts due from joint interest owners or purchasers are stated net of an allowance for doubtful accounts when the Company believes collection is doubtful. For receivables from joint interest owners, the Company typically has the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Accounts receivable outstanding longer than the contractual payment terms are considered past due. The Company determines its allowance by considering a number of factors, including the length of time accounts receivable are past due, the Company's previous loss history, the debtor's current ability to pay its obligation to the Company, the condition of the general economy and the industry as a whole. The Company writes off specific accounts receivable when they become uncollectible, and payments subsequently received on such receivables are credited to the allowance for doubtful accounts. No allowance was deemed necessary at December 31, 2017 or December 31, 2016.

Accounts receivable is comprised of the following as of December 31, 2017 and 2016:

	December 31, 2017		December 31, 2016	
	Related Parties	Third-Parties	Related Parties	Third-Parties
	(In thousands)			
Revenue receivable	$ 13,601	$ 1,153	$ 4,554	$ 1,291
Transaction purchase price settlement	2,381	—	—	—
Joint interest billings	20	83	283	557
Other	20	291	—	80
Accounts receivable	$ 16,022	$ 1,527	$ 4,837	$ 1,928

Significant Customers. All of the revenue receivable from related parties is attributable to Gateway Gathering and Marketing. Each of the following purchasers accounted for 10% or more of the Company's revenue for the periods presented:

	Year Ended December 31,		
	2017	2016	2015
Gateway Gathering and Marketing (1)	80%	70%	54%
ETC Field Services, LLC	10	17	—
Sunoco Inc.	—	—	13
Enlink Midstream Services, LLC	—	10	11
Regency Energy Partners, LP	—	—	11

(1) For a further discussion see Note 15 - *Related Party Transactions*

Revenue Recognition

The Company derives its revenue primarily from the sale of produced oil, natural gas, and NGLs. Revenue is recognized when the Company's production is delivered to the purchaser, but payment is generally received between 30 and 90 days after the date of production. No revenue is recognized unless it is determined that title to the product has transferred to a purchaser. At the end of each month, the Company make estimates of the amount of production delivered to the purchaser and the price it will receive. The Company uses its knowledge of its properties, contractual arrangements, NYMEX and local spot market prices, and other factors as the basis for these estimates. Variances between the estimates and the actual amounts received are recorded in the month payment is received. Transportation expenses for oil are included as a reduction to oil revenues, while gathering and transportation expenses for natural gas and NGLs are recorded within gathering and transportation.

Successful Efforts Method of Accounting for Oil and Natural Gas Activities

Oil and natural gas exploration, development and production activities are accounted for under the successful efforts method of accounting. Under this method, the costs incurred to acquire, drill, and complete productive wells and development wells are capitalized. Oil and gas lease acquisition costs are also capitalized.

Proved Oil and Natural Gas Properties. If proved reserves are found for these properties, costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering, and storing oil, natural gas, and NGLs are capitalized. All costs incurred to drill and equip successful exploratory wells, development wells, development-type stratigraphic test wells, and service wells, including unsuccessful development wells, are capitalized. Capitalized costs attributed to the properties and mineral interests are subject to depreciation, depletion and amortization ("DD&A"). Depletion of capitalized costs is provided using the units-of-production method based on proved oil and gas reserves related to the associated reservoir. If no proved reserves have been found, the costs of each of the related exploratory wells are charged to expense.

Unproved Properties. Acquisition costs associated with the acquisition of non-producing leaseholds are recorded as unproved leasehold costs and capitalized as incurred. These consist of costs incurred in obtaining a mineral interest or right in a property, such as a lease in addition to options to lease, broker fees, recording fees, and other similar costs related to acquiring properties. Leasehold costs are classified as unproved until proved reserves are discovered, at which time related costs are transferred to proved oil and natural gas properties.

Exploration Costs. Exploration costs, other than exploration drilling costs, are charged to expense as incurred. These costs include personnel and other internal costs, geological and geophysical expenses, exploratory dry holes, delay rentals for leases, and cost associated with unsuccessful lease acquisitions. The costs of drilling exploratory wells and exploratory-type stratigraphic wells are initially capitalized 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.

In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. The costs of such exploratory wells are expensed if a determination of proved reserves has not been made within a 12-month period after drilling is complete.

For sales of a complete or partial unit of proved and unproved properties, and related facilities, the cost and related accumulated DD&A are removed from the property accounts and gain or loss is recognized for the difference between the proceeds received and the net carrying value of the properties sold.

Impairment of Oil and Natural Gas Properties

The Company's proved oil and natural gas properties are recorded at cost. The Company's proved properties are evaluated for impairment on a field-by-field basis whenever events or changes in circumstances indicate that an asset’s carrying value may not be recoverable. The Company compares expected undiscounted future cash flows to the net book value of the asset. If the future undiscounted expected cash flows, based on its estimate of future oil and natural gas prices, operating costs and anticipated production from proved reserves and risk-adjusted probable and possible reserves, are lower than the net book value of the asset, the capitalized cost is reduced to fair value. Commodity pricing is estimated by using WTI and Henry Hub natural gas NYMEX strip market pricing, adjusted for quality, transportation fees and a regional price differential. Fair value is calculated by discounting the future cash flows at a rate of 10%. The Company believes a 10% discount rate is commonly used by oil and gas industry peers, analysts, and investors in evaluating the monetary significance of oil and gas properties and for comparing the size and value of proved reserves among companies in our industry. Accordingly, the Company currently believes a 10% discount rate is consistent with a rate a market participant would consider in evaluating onshore domestic proved oil and gas reserves and produces a reasonable estimate of fair value.

Unproved oil and natural gas properties are assessed periodically, and no less than annually, for impairment on an aggregate basis based on remaining lease term, drilling results, reservoir performance, seismic interpretation and future plans to develop acreage. As unproved oil and natural gas properties are developed and reserves are proved, the capitalized costs are subject to depreciation and depletion. If the development of these properties is deemed unsuccessful, the capitalized costs related to the unsuccessful activity is expensed in the year the determination is made. The rate at which the unproved oil and natural gas properties are written off or reclassified to proved oil and natural gas properties depends on the timing and success of the Company's future exploration and development program.

Oil and Natural Gas Reserve Quantities

The Company's estimated proved reserve quantities and future net cash flows are critical to the understanding of the value of its business. They are used in comparative financial ratios and are the basis for significant accounting estimates in its financial statements, including the calculations of depletion and impairment of proved oil and natural gas properties. Future cash inflows and future production and development costs are determined by applying prices and costs, including transportation, quality differentials, and basis differentials, applicable to each period to the estimated quantities of proved reserves remaining to be produced as of the end of that period. Expected cash flows are discounted to present value using an appropriate discount rate. For example, the standardized measure calculations require a 10% discount rate to be applied. Although reserve estimates are inherently imprecise, and estimates of new discoveries and undeveloped locations are more imprecise than those of established producing oil and gas properties, the Company makes a considerable effort in estimating our reserves. The Company expects proved reserve estimates will change as additional information becomes available and as commodity prices and operating and capital costs change. The Company has and expects to evaluate and estimate its proved reserves each year-end. For purposes of depletion and impairment, reserve quantities are adjusted in accordance with U.S. GAAP for the impact of additions and dispositions.

Other Property and Equipment

Other property and equipment such as office furniture and equipment, buildings, computer hardware and software is recorded at cost. Depreciation is calculated using the straight-line method over the estimated useful lives of the assets ranging from three to twenty years. Major renewals and improvements are capitalized while expenditures for maintenance and repairs are expensed as incurred. When other property and equipment is sold or retired, the capitalized costs and related accumulated depreciation are removed from the accounts.

Asset Retirement Obligations

An asset retirement obligation ("ARO") represents the estimated present value of the amount a company will incur to retire a long-lived asset at the end of its productive life, in accordance with applicable state laws. The Company recognizes an estimated liability for future costs primarily associated with the abandonment of its oil and natural gas properties and related assets. The amount of the ARO is determined by calculating the present value of estimated cash flows related to the liability. The retirement obligation is recorded as a liability at its estimated present value at inception (i.e. at the time the well is drilled or acquired and related assets are placed into service) with an offsetting increase in the carrying amount of the related long-lived asset that is included in proved oil and natural gas properties in the accompanying consolidated balance sheets. Periodic accretion of discount of the estimated liability is recorded as an expense in the consolidated statements of operation. The Company depreciates the long-lived asset, including the asset retirement cost, over its useful life, and recognizes expense in connection with the accretion of the discounted liability over the remaining estimated economic lives of the respective oil and natural gas properties.

An asset retirement liability is determined using significant assumptions, including current estimates of plugging and abandonment costs, annual inflation of these costs, the productive lives of assets, and the Company's risk-adjusted interest rate. Changes in any of these assumptions can result in significant revisions to the estimated asset retirement obligation. Because of the subjectivity of assumptions, the costs to ultimately retire the Company's wells may vary significantly from prior estimates. See Note 9 - *Asset Retirement Obligations* for a further discussion.

Deferred Financing Costs

Deferred financing costs and discounts related to the Company's Revolving Credit Facility and its Second Lien Notes are included in other long-term assets and long-term debt, respectively, in the consolidated balance sheets and are stated at cost, net of amortization. The deferred financing costs associated with the Revolving Credit Facility and the Second Lien Notes are amortized to interest expense on a straight-line basis and an effective rate of interest method, respectively, over the borrowing terms. See Note 8 - *Long term debt* for a further discussion.

Commodity Derivative Instruments

The Company utilizes commodity derivative instruments including swaps, collars, basis swaps, and other similar agreements to manage its exposure to oil and natural gas price volatility (i.e., price risk) associated with the forecasted sale of a portion its oil and natural gas production. These commodity derivative instruments are not designated as hedges for accounting purposes. Accordingly, the Company records derivative instruments on the consolidated balance sheets as either an asset or liability measured at fair value and records changes in the fair value of derivatives in current earnings in the consolidated statements of operations as they occur in the period of change. Gains and losses on commodity derivatives and premiums paid for put options are included in cash flows from operating activities.

To the extent legal right of offset exists with a counterparty, the Company reports derivative assets and liabilities on a net basis. The Company has exposure to credit risk to the extent the counterparty is unable to satisfy its settlement obligation. The Company actively monitors the creditworthiness of counterparties and assesses the impact, if any, on its derivative position. See Note 4 - *Derivative Instruments* for a further discussion.

Fair Value of Financial Instruments

Fair value represents the price that would be received to sell the asset or paid to transfer the liability in an orderly transaction between market participants at the reporting date. The Company's assets and liabilities that are measured at fair value at each reporting date are classified according to a hierarchy that prioritizes inputs and assumptions underlying the valuation techniques. This fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities and the lowest priority to unobservable inputs and consists of three broad levels:

***Level 1*:**	Observable inputs that reflect unadjusted quoted prices for identical assets or liabilities in active markets as of the reporting date.
***Level 2*:**	Observable market-based inputs or unobservable inputs that are corroborated by market data. These are inputs other than quoted prices in active markets included in Level 1 that are either directly or indirectly observable as of the reporting date.
***Level 3*:**	Unobservable inputs that are not corroborated by market data and may be used with internally developed methodologies that result in management's best estimate of fair value.

Valuation techniques that maximize the use of observable inputs are favored. Assets and liabilities are classified in their entirety based on the lowest priority level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the placement of assets and liabilities within the levels of the fair value hierarchy. Reclassifications of fair value between Level 1, Level 2 and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter.

Income Taxes

The Company accounts for income taxes using the asset and liability method. Under this method, deferred tax assets and liabilities are recognized for the estimated future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are calculated by applying existing tax laws and the rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect of a change in tax rates on deferred tax assets and liabilities is recognized in the year of the enacted rate change.

The Company accounts for uncertainty in income taxes using a recognition and measurement threshold for tax positions taken or expected to be taken in a tax return, which are subject to examination by federal and state taxing authorities. The tax benefit from an uncertain tax position is recognized when it is more likely than not that the position will be sustained upon examination by taxing authorities based on technical merits of the position. The amount of the tax benefit recognized is the largest amount of the benefit that has a greater than 50% likelihood of being realized upon ultimate settlement. The effective tax rate and the tax basis of assets and liabilities reflect management’s estimates of the ultimate outcome of various tax uncertainties. The Company recognizes penalties and interest related to uncertain tax positions within the provision (benefit) for income taxes line in the accompanying consolidated statements of operations.

Rosehill Operating, the Company’s accounting predecessor, is a limited liability company treated as a partnership for U.S. federal income tax purposes that is not subject to U.S. federal income tax.

Earnings (Loss) Per Share

The two-class method of computing earnings per share is required for entities that have participating securities. The two-class method is an earnings allocation formula that determines earnings per share for participating securities according to dividends declared (or accumulated) and participation rights in undistributed earnings. Our Class B Common Stock has no economic interest in the earnings of the Company. Basic earnings (loss) per common share is calculated by dividing net income (loss) attributable to common shareholders by the weighted average number of shares of Class A Common Stock outstanding each period. Diluted earnings per share adds to those shares the incremental shares that would have been outstanding assuming exchanges of the Company's outstanding Class B Common Stock, Series A Preferred Stock and warrants for Class A Common Stock, and the vesting of unvested restricted stock units of Class A Common Stock. An anti-dilutive impact is an increase in earnings per share or a reduction in net loss per share resulting from the conversion, exercise, or contingent issuance of certain securities.

The Company uses the "if-converted" method to determine the potential dilutive effect of conversions of its outstanding Class B Common Stock and Series A Preferred Stock, and the treasury stock method to determine the potential dilutive effect of its outstanding warrants exercisable for shares of Class A Common Stock and the vesting of unvested restricted stock units of Class A Common Stock.

Beneficial Conversion Feature in the Series A Preferred Stock

The non-detachable conversion option embedded in the Series A Preferred Stock was evaluated to determine whether a beneficial conversion feature existed as of the closing date of the Transaction which would be recognized separately from the Series A Preferred Stock in the Company's consolidated financial statements. The conversion option is considered beneficial if, at the commitment closing date, the effective conversion price (represented by the proceeds received less the allocated value of the warrants and Class A Common Stock) for the Series A Preferred Stock is less than the fair value of the Class A Common Stock into which it is convertible at the commitment closing date. As a result of this evaluation, the Company separately recognized in equity, with an offsetting reduction in the carrying amount of the Series A Preferred Stock, the value of the beneficial conversion feature at the commitment date of $6.7 million. Since the Company's Series A Preferred Stock is perpetual and has no stated maturity date and no restrictions on conversion, the value attributable to the non-detachable conversion option was recognized immediately as a non-cash deemed dividend on the date that the Series A Preferred Stock was issued.

Future issuances of Series A Preferred Stock resulting from dividends paid-in-kind may, depending on the trading price per share of the Company's Class A Common Stock on the dividend date, contain a beneficial conversion option determined on the same basis as described above and, thus, result in additional non-cash deemed dividends which will reduce net income attributable to Rosehill Resources Inc. common stockholders when such paid-in-kind preferred shares are granted.

Recently Issued Accounting Standards Adopted in 2017

The Company is an “emerging growth company,” as defined in Section 2(a) of the Securities Act of 1933, as amended, (the “Securities Act”), as modified by the Jumpstart our Business Startups Act of 2012, (the “JOBS Act”), and it may take advantage of certain exemptions from various reporting requirements that are applicable to other public companies that are not emerging growth companies including, but not limited to, not being required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act, reduced disclosure obligations regarding executive compensation in its periodic reports and proxy statements, and exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and shareholder approval of any golden parachute payments not previously approved.

Further, Section 102(b)(1) of the JOBS Act exempts emerging growth companies from being required to comply with new or revised financial accounting standards until private companies (that is, those that have not had a Securities Act registration statement declared effective or do not have a class of securities registered under the Exchange Act) are required to comply with the new or revised financial accounting standards. The JOBS Act provides that a company can elect to opt out of the extended transition period and comply with the requirements that apply to non-emerging growth companies but any such election to opt out is irrevocable. The Company has elected not to opt out of such extended transition period, which means that when a standard is issued or revised and it has different application dates for public or private companies, the Company, as an emerging growth company, can adopt the new or revised standard at the time private companies adopt the new or revised standard. This may make comparison of the Company’s financial statements with another public company which is neither an emerging growth company nor an emerging growth company which has opted out of using the extended transition period difficult or impossible because of the potential differences in accounting standards used.

Deferred Taxes. In November 2015, the FASB issued ASU 2015-17*, Income Taxes (Topic 704): Balance Sheet Classification of Deferred Taxes*. ASU No. 2015-17 eliminated the current requirement for organizations to present deferred tax liabilities and assets as current and non-current in a classified balance sheet. Instead, companies are required to classify all deferred tax assets and liabilities as non-current. ASU 2015-17 is effective for interim and annual periods beginning after December 15, 2016. The adoption of this ASU did not have a material impact on the Company's financial statements.

Business Combinations. In January 2017, the FASB issued ASU 2017-01, *Business Combinations (Topic 805): Clarifying the Definition of a Business*, which clarifies the definition of a business with the objective of adding guidance to assist entities with evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. ASU 2017-01 is effective for the Company for fiscal years beginning after December 15, 2018, and interim periods within fiscal years beginning after December 15, 2019. The adoption of this ASU, using a prospective approach, could have a material impact on the financial statements and related disclosures if future acquisitions or disposals are treated as asset purchases (or sales) rather than acquisition or disposal of a business. The Company elected to early adopt this ASU in connection with the White Wolf Acquisition, and has accounted for the White Wolf Acquisition as an acquisition of assets. See Note 3 - *Acquisitions and Divestitures* for further detail.

Statement of Cash Flows - Restricted Cash. In November 2017, the FASB issued ASU 2016-18, *Statement of Cash Flows (Topic 230): Restricted Cash*, a consensus of the FASB's Emerging Issues Task Force. This new standard requires that the statement of cash flows explain the change during the period in the combined total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents when reconciling the beginning and end of period balances on the statement of cash flow. This new guidance also requires that the Company disclose how the statement of cash flows reconciles to the balance sheet when the balance sheet includes more than one line item of cash, cash equivalents, and restricted cash. The Company adopted this ASU during the year ended December 31, 2017 and retroactively presented.

Statement of Cash Flows. In August 2016, the FASB issued ASU 2016-15, *Statement of Cash Flows (Topic 320): Classification of Cash Receipts and Cash Payments*, which addresses eight specific cash flow issues with the objective of reducing the existing diversity of presentation and classification in the statement of cash flows. The new standard applies to cash flows associated with debt payment or debt extinguishment costs, settlement of zero-coupon debt or other debt instruments with coupon rates that are insignificant in relation to effective interest rate of borrowing, contingent consideration payments made after a business combination, proceeds from the settlement of insurance claims, proceeds from the settlement of corporate-owned life insurance policies, distributions received from equity method investees, beneficial interests in securitization transactions and separately identifiable cash flows and application of the predominance principle. ASU 2016-15 is effective for the Company for fiscal years beginning after December 15, 2018, and interim periods within fiscal years beginning after December 15, 2019. Early adoption is permitted, but only if all amendments are adopted in the same period. The adoption of the ASU did not have a material impact on the Company's consolidated financial statements and related disclosures.

Recently Issued Accounting Standards Not Yet Adopted

Revenue Recognition. In August 2015, the FASB issued ASU 2015-14, *Revenue from Contracts with Customers (Topic 606): Deferral of Effective Date*, which defers the effective date of ASU 2014-09 by one year to be effective for annual reporting periods beginning after December 15, 2018, and interim reporting periods within annual reporting periods beginning after December 31, 2019. ASU 2014-09, *Revenue from Contracts with Customers*, supersedes the revenue recognition requirements in *Topic 605, Revenue Recognition*, and industry-specific guidance in *Subtopic 932-605, Extractive Activities-Oil and Gas-Revenue Recognition* and requires an entity to recognize revenue when it transfers promised goods or services to customers in an amount that reflects the consideration the entity expects to be entitled to in exchange for those goods or services. Subsequently, in April 2016, the FASB issued ASU 2016-10, *Revenue from Contracts with Customers (Topic 606): Identifying Performance Obligations and Licensing* as further clarification on identifying performance obligations and the licensing implementation guidance. In May 2016, the FASB issued ASU 2016-12, *Revenue from Contracts with Customers (Topic 606): Narrow-Scope Improvements and Practical Expedients*, as clarifying guidance to improve the operability and understandability of the implementation guidance on principal versus agent considerations. In December 2016, the FASB further issued ASU 2016-20, *Technical Corrections and Improvements to Topic 606, Revenue from Contracts with Customers*, to increase stakeholders' awareness of the proposals and to expedite improvements to ASU 2014-09. The Company is still in the early stages of evaluating this ASU.

Leases. In February 2016, the FASB issued ASU 2016-02, *Leases (Topic 842),* which requires the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases under previous U.S. GAAP. ASU 2016-02 is effective for the Company for fiscal years beginning after December 15, 2019, and interim periods within fiscal years beginning after December 15, 2020. Early adoption is permitted. The method of adoption and impact this standard will have on the financial statements and related disclosures is currently being evaluated.

Financial Instruments – Credit Losses. In June 2016, the FASB issued ASU 2016-13, *Financial Instruments – Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments* requiring the measurement of all expected credit losses for financial assets, which include trade receivables, held at the reporting date based on historical experience, current conditions, and reasonable and supportable forecasts. The guidance in this ASU is effective for the Company for fiscal years beginning after December 15, 2020, and interim periods within fiscal years beginning after December 15, 2021 with early adoption permitted for interim and annual periods beginning after December 15, 2018. The evaluation of this standard and its impact on the financial statements and related disclosures is currently being assessed.

Non-financial assets. In February 2017, the FASB issued ASU 2017-05, *Other Income – Gains and Losses from the Derecognition of Nonfinancial Assets (Subtopic 610-20): Clarifying the Scope of Asset Derecognition Guidance and Accounting* *for Partial Sales of Nonfinancial Assets*, which clarifies the scope of Subtopic 610-20 and provides further guidance for partial sales of nonfinancial assets. Subtopic 610-20, which was issued in May 2014 as part of ASU 2014-09, provides guidance for recognizing gains and losses from the transfer of nonfinancial assets in contracts with noncustomers. An entity is required to apply the amendments in ASU 2017-05 at the same time it applies the amendments in ASU 2014-09. Therefore, ASU 2017-05 is effective for the Company for fiscal years beginning after December 15, 2018, and interim periods within fiscal years beginning after December 15, 2019. An entity may elect to apply the amendments in ASU 2017-05 either retrospectively to each period presented in the financial statements in accordance with the guidance on accounting changes in FASB's Accounting Standards Codification ("ASC") Topic 250, *Accounting Changes and Error Corrections*, paragraphs 10-45-5 through 10-45-10 (i.e. the retrospective approach) or retrospectively with a cumulative-effect adjustment to retained earnings as of the beginning of the fiscal year of adoption (i.e. the modified retrospective approach). An entity may elect to apply all of the amendments in ASU 2017-05 and ASU 2014-09 using the same transition method, and alternatively may elect to use different transition methods. Entities may apply the guidance earlier as of annual reporting periods beginning after December 15, 2016, including interim reporting periods within that reporting period. The impact ASU 2017-05 will have on the financial statements and related disclosures is currently ongoing.

Equity-based Compensation. In May 2017, the FASB issued ASU 2017-09 – *Compensation – Stock Compensation (Topic 718); Scope of Modification Accounting.* The new guidance clarifies when to account for a change to the terms or conditions of a share-based payment award as a modification. Under the new guidance, modification accounting is required only if the fair value, the vesting conditions, or the classification of the award as equity or liability changes as a result of the change in terms or conditions. This ASU is not expected to have a material impact on the Company's consolidated financial results.

Earnings Per Share, Derivatives and Hedging, Mandatorily Redeemable Noncontrolling Interests. In July 2017, the FASB issued ASU 2017-11—*Earnings Per Share (Topic 260); Distinguishing Liabilities from Equity (Topic 480); Derivatives and Hedging (Topic 815): (Part I) Accounting for Certain Financial Instruments with Down Round Features, (Part II) Replacement of the Indefinite Deferral for Mandatorily Redeemable Financial Instruments of Certain Nonpublic Entities and Certain Mandatorily Redeemable Noncontrolling Interests with a Scope Exception*. The amendments in Part I of ASU 2017-11 change the classification analysis of certain equity-linked financial instruments (or embedded features) with down round features and also clarify existing disclosure requirements for equity-classified instruments. For the Company, the amendments in Part I of this Update are effective for fiscal years beginning after December 15, 2019, and interim periods within fiscal years beginning after December 15, 2020. Early adoption is permitted, including adoption in an interim period. If an entity early adopts the amendments in an interim period, any adjustments should be reflected as of the beginning of the fiscal year that includes that interim period.

Derivatives and Hedging. In August 2017, the FASB issued ASU 2017-12, *Derivatives and Hedging (Topic 815): Targeted Improvements to Accounting for Hedging Activities*, which expands and refines hedge accounting for both financial and non-financial risk components, aligns the recognition and presentation of the effects of hedging instruments and hedge items in the financial statements, and includes certain targeted improvements to ease the application of current guidance related to the assessment of hedge effectiveness. ASU 2017-12 is effective for the Company for fiscal years beginning after December 15, 2019. Early adoption is permitted. The Company has not yet evaluated the impact of this standard on its financial statements and related disclosures.

Note 3 - Acquisitions and Divestiture

White Wolf Acquisition

In December 2017, the Company acquired mineral rights and other associated assets and interests in the Southern Delaware Basin (the "White Wolf Acquisition") for approximately $116.6 million, subject to customary purchase price adjustments, pursuant to a Purchase and Sale Agreement (the "PSA") from certain sellers named therein (the "Sellers"). Subject to certain conditions under the PSA, until March 8, 2018, Rosehill Operating had the option to acquire additional oil and natural gas leases located within a certain designated area in the Delaware Basin (the "Designated Area") from the Sellers. The option to purchase

Additional Interest in the Designated Area expired on March 8, 2018 with the Company not acquiring any additional acreage. The Company incurred transaction fees of $2.9 million in connection with the White Wolf Acquisition, which were capitalized.

In addition to acquiring mineral rights, some of the leases contained producing wells and their associated personal property such as tank batteries and pumping units, which were holding those particular leases. The Company acquired the asset retirement obligation for those producing wells and associated personal property which totaled $1.6 million as of December 31, 2017. Total consideration paid in connection with the White Wolf Acquisition was $121.1 million. The Company accounted for the White Wolf Acquisition as an asset acquisition. The total consideration was recorded to unproved oil and natural gas properties and the liability acquired was recorded to asset retirement obligation based on relative fair value.

As of December 31, 2017, $4.0 million of the White Wolf Acquisition purchase price was in an escrow account. The PSA required that $4.0 million be placed in an escrow account to provide a non-exclusive source of funds to satisfy any liabilities incurred or sustained by the Company arising from any claims that the Sellers have indemnity obligations under the terms of the PSA. The funds were required to be escrowed until March 8, 2018, at which time any unused cash in the escrow account would be remitted to the Sellers. The Company did not use any of the escrowed funds and the full amount was released to the Seller in March 2018.

Other Acquisitions

In the second quarter of 2017, Rosehill Operating completed the purchase of additional working interests in various operated wells and leasehold interests in Loving County, Texas, from unaffiliated individuals and entities for total consideration of $6.5 million, which approximates fair value. The effective date of the purchase of the working interests was May 1, 2017. The acquisition was accounted for as a business acquisition. The difference between the historical results of operations and the unaudited pro forma results of operations was determined to be de minimus and therefore not provided.

Barnett Shale Divestiture

On November 2, 2017, the Company consummated the sale of Barnett Shale assets for a purchase price of approximately $7.1 million. After customary purchase price adjustments, the net purchase price was approximately $6.5 million, which resulted in gain on sale of $5.3 million. The divestiture of the Barnett Shale assets did not represent a strategic shift with a major effect on the Company's operations and financial results, therefore, was not reported as a discontinued operation.

Note 4 – Derivative Instruments

The Company enters into various derivative instruments primarily to mitigate a portion of the exposure to potentially adverse market changes in oil and natural gas commodity prices and the associated impact on cash flows. All contracts are entered into for other-than-trading purposes. Oil and natural gas commodity derivative instruments are recorded on the balance sheet at fair value as either an asset or a liability with changes in fair value recognized currently in earnings. While commodity derivative instruments are utilized to manage the price risk attributable to expected oil and natural gas production, the Company's commodity derivative instruments are not designated as accounting hedges under the accounting guidance. The related cash flow impact of the commodity derivative activities is reflected as cash flows from operating activities unless they are determined to have a significant financing element at inception, in which case they are classified within financing activities. A description of the Company’s derivative financial instruments is provided below:

Fixed price swaps - The Company receives a fixed price for the contract and pays a floating market price to the counterparty.

Purchased put options - The Company purchases put options based on an index price from the counterparty by payment of a cash premium. If the index price is lower than the put’s strike price at the time of settlement, the Company receives from the counterparty such difference between the index price and the purchased put strike price. If the market price settles above the put’s strike price, no payment is due from either party.

Two-way costless collars - Arrangements that contain a fixed floor price (purchased put option) and a fixed ceiling price (sold call option) based on an index price which, in aggregate, have no net cost. At the contract settlement date, (1) if the index price is higher than the ceiling price, the Company pays the counterparty the difference between the index price and ceiling price, (2) if the index price is between the floor and ceiling prices, no payments are due from either party, and (3) if the index price is below the floor price, the Company will receive the difference between the floor price and the index price.

Three-way costless collars - Arrangements that contain a purchased put option, a sold call option and a sold put option based on an index price which, in aggregate, have no net cost. At the contract settlement date,

(1) if the index price is higher than the sold call strike price, the Company pays the counterparty the difference between the index price and sold call strike price,

(2) if the index price is between the purchased put strike price and the sold call strike price, no payments are due from either party,

(3) if the index price is between the sold put strike price and the purchased put strike price, the Company will receive the difference between the purchased put strike price and the index price, and (4) if the index price is below the sold put strike price, the Company will receive the difference between the purchased put strike price and the sold put strike price

Basis swaps - Arrangements that guarantee a price differential for natural gas from a specified delivery point. The Company receives a payment from the counterparty if the price differential is greater than the stated terms of the contract and pays the counterparty if the price differential is less than the stated terms of the contract.

Interest rate swaps -Interest rate swaps are used to fix or float interest rates on existing or anticipated indebtedness. The purpose of these instruments is to manage the Company's existing or anticipated exposure to unfavorable interest rate changes.

Tema's interest rate swap was terminated by Tema on April 20, 2017. At the closing of the Transaction, selected crude oil options and natural gas options were designated to remain with Tema. In connection with the Transaction, certain crude oil swaps and natural gas swaps were transferred to the Company. Contracts with one counterparty were novated to the Company in July 2017.

Series B Preferred Stock bifurcated derivative - In the event of a change of control, the Company shall redeem in cash all of the outstanding shares of Series B Preferred Stock, excluding Series B PIK Shares as defined in Note 10 - *10% Series B Redeemable Preferred Stock*, for a price per share equal to the Base Return Amount as defined in Note 10 - *10% Series B Redeemable Preferred Stock*. The Company assessed the change of control feature and determined that the redemption of the outstanding shares of Series B Preferred stock excluding Series B PIK Shares, for a price per share equal to the Base Return Amount was a bifurcated derivative. See Note 10 - *10% Series B Redeemable Preferred Stock* for defined terms and more detail.

The fair value of the derivative assets and liabilities is as follows as of the following dates:

	December 31, 2017		
	Gross Fair Value	Gross Amounts Offset (1)	Net Recognized Fair Value
	(In thousands)		
Assets			
Commodity derivatives - current	$ 1,079	$ (1,079)	$ —
Commodity derivatives - non-current	120	(120)	—
Total assets	$ 1,199	$ (1,199)	$ —
Liabilities			
Commodity derivatives - current	$ (11,851)	$ 1,079	$ (10,772)
Commodity derivatives - non-current	(7,503)	120	(7,383)
Series B Preferred Stock bifurcated derivative - non-current	(625)	—	(625)
Total liabilities	$ (19,979)	$ 1,199	$ (18,780)

(1) The Company has agreements in place with all of its counterparties that allow for the financial right of offset for derivative assets and liabilities.

	December 31, 2016		
	Gross Fair Value	Gross Amounts Offset (1)	Net Recognized Fair Value
	(In thousands)		
Assets			
Commodity derivatives - current	$ 556	$ (309)	$ 247
Commodity derivatives - non-current	—	—	—
Total assets	$ 556	$ (309)	$ 247
Liabilities			
Commodity derivatives - current	$ (2,164)	$ 309	$ (1,856)
Commodity derivatives - non-current	—	—	—
Total liabilities	$ (2,164)	$ 309	$ (1,856)

(1) The Company has agreements in place with all of its counterparties that allow for the financial right of offset for derivative assets and liabilities.

In a typical commodity swap agreement, if the agreed upon published third-party index price ("index price") is lower than the swap fixed price, the Company receives the difference between the index price and the agreed upon swap fixed price. If the index price is higher than the swap fixed price, the Company pays the difference.

As of December 31, 2017, the open commodity derivative positions with respect to future production were as follows:

	2018	2019	2020	2021	2022
Commodity derivative swaps					
Oil:					
Notional volume (Bbl)	2,350,000	1,704,000	960,000	360,000	250,000
Weighted average price ($/Bbl)	$ 54.28	$ 52.85	$ 51.37	$ 50.69	$ 50.21
Natural Gas:					
Notional volume (MMBtu)	4,040,000	2,160,000	1,500,000	1,200,000	1,000,000
Weighted average fixed price ($/MMBtu)	$ 3.10	$ 2.89	$ 2.84	$ 2.86	$ 2.86

For the years ended December 31, 2017, 2016 and 2015, the effect of the derivative activity on the Company's Consolidated Statements of Operations was as follows:

	Year Ended December 31,		
	2017	2016	2015
		(In thousands)	
Gain (loss) on settled derivatives			
Commodity options	$ 172	$ 511	$ 4,340
Commodity swaps	45	(1,334)	130
Total	217	(823)	4,470
Interest rate swap	(143)	(785)	(1,165)
Total gain (loss) on settled derivatives	$ 74	$ (1,608)	$ 3,305
Gain (loss) on unsettled derivatives			
Commodity derivative options	$ 313	$ (1,508)	$ (735)
Commodity derivative swaps	(16,866)	(1,838)	—
Total	(16,553)	(3,346)	(735)
Interest rate swap	(226)	324	(677)
Total gain (loss) on unsettled derivatives	$ (16,779)	$ (3,022)	$ (1,412)

The gains and losses resulting from the cash settlement and mark-to-market of unsettled commodity derivatives are included within "Other income (expense)" in the Consolidated Statements of Operations. The gains and losses resulting from the cash settlement and mark-to-market of the interest rate swap are included in "Interest expense, net" in the Consolidated Statements of Operations.

Note 5 – Fair Value Measurements

Financial Instruments

The financial instruments measured at fair value on a recurring basis consist of the following:

	December 31, 2017	December 31, 2016
	(In thousands)	
Derivative assets (liabilities)		
Derivative assets - current	$ —	$ 247
Derivative liabilities - current	(10,772)	(1,856)
Derivative liabilities - non-current	(8,008)	—
Total derivative assets (liabilities), net	$ (18,780)	$ (1,609)

Derivative assets and liabilities primarily represent unsettled amounts related to commodity derivative positions, including swaps and options. Derivative liabilities also include the Series B Preferred Stock bifurcated derivative for the various redemption amounts that the Company could incur if a change of control event occurs. The Company utilizes Level 3 assumptions to estimate the probability of a change in control occurring and when that would occur as the timing impacts the Base Return Amount as defined in Note 10 - *10% Series B Redeemable Preferred Stock*.

The tables below set forth by level within the fair value hierarchy represent the gross components of the assets and liabilities that were measured at fair value on a recurring basis as of December 31, 2017 and 2016. These gross balances are intended solely to provide information on sources of inputs to fair value and proportions of fair value involving objective versus subjective valuations and do not represent either the actual credit exposure or net economic exposure.

	December 31, 2017			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Derivative assets (liabilities)				
Commodity derivative liabilities - current	$ —	$ (10,772)	$ —	$ (10,772)
Commodity derivative liabilities - non-current	—	(7,383)	—	(7,383)
Series B Preferred Stock bifurcated derivative - non-current	—	—	(625)	(625)
Total derivative assets (liabilities), net	$ —	$ (18,155)	$ (625)	$ (18,780)

	December 31, 2016			
	Level 1	Level 2	Level 3	Total
	(In thousands)			
Derivative assets (liabilities)				
Commodity derivative assets - current	$ 21	$ 226	$ —	$ 247
Commodity derivative liabilities - current	(1,856)	—	—	(1,856)
Total derivative assets (liabilities), net	$ (1,835)	$ 226	$ —	$ (1,609)

The carrying amounts of the Company's cash and cash equivalents, accounts receivable, accounts payable, and accrued liabilities approximate fair value because of the short-term maturities and/or liquid nature of these assets and liabilities. The carrying values of the amounts outstanding under the credit agreement approximate fair value because the variable interest rates are reflective of current market conditions.

Financing Arrangements

The fair value measurements for amounts outstanding under the Revolving Credit Facility and the 10.00% Senior Secured Second Lien Notes (see Note 8 - *Long term* d*ebt*) represent Level 2 inputs. The carrying value of the 10% Senior Secured Second Lien Notes are representative of their fair values as of December 31, 2017 because the instruments were negotiated on an arm's length basis with reputable third-party lenders at prevailing market rates in December 2017. The Revolving Credit Facility book value is representative of its fair value because the interest rate changes monthly based on the current market of the stated rates in the agreement.

Non-Financial Assets and Liabilities

The fair value measurements of assets acquired and liabilities assumed are measured on a nonrecurring basis on the acquisition date using an income valuation technique based on inputs that are not observable in the market and therefore represent Level 3 inputs. Significant inputs to the valuation of acquired oil and gas properties include estimates of: (i) reserves; (ii) production rates; (iii) future operating and development costs; (iv) future commodity prices, including price differentials; (v) future cash flows; and (vi) a market participant-based weighted average cost of capital rate. These inputs require significant judgments and estimates by the Company’s management at the time of the valuation. Refer to Note 3 - *Acquisitions and Divestitures* for additional information on the fair value of assets acquired during 2017.

Non-financial assets and liabilities that are initially measured at fair value are comprised of asset retirement obligations and the corresponding increase to the related long-lived asset and are not remeasured at fair value in subsequent periods. Such initial measurements are classified as Level 3 since certain significant unobservable inputs are utilized in their determination. The fair value of additions to asset retirement obligation liability and certain changes in the estimated fair value of the liability are measured using valuation techniques consistent with the income approach, converting future cash flows to a single discounted amount. Significant inputs to the valuation include (i) estimated plug and abandonment cost per well based on historical experience and information from third-party vendors; (ii) estimated remaining life per well; (iii) future inflation factors; and (iv) average credit-adjusted risk-free rate. These inputs require significant judgments and estimates by management at the time of the valuation and are the most sensitive and subject to change.

If the carrying amount of oil and natural gas properties exceeds the estimated undiscounted future cash flows, the carrying amount of the oil and natural gas properties will be adjusted to the fair value. The fair value of oil and natural gas properties is determined using valuation techniques consistent with the income and market approach. The factors used to determine fair value are subject to management’s judgment and expertise and include, but are not limited to, (i) recent sales prices of comparable properties; (ii) the present value of future cash flows, net of estimated operating and development costs using estimates of proved oil and natural gas reserves; (iii) future commodity prices; (iv) future production estimates; (v) anticipated capital expenditures; and (vi) various discount rates commensurate with the risk and current market conditions associated with the projected cash flows. These assumptions represent “Level 3” inputs.

Note 6 – Property and equipment

Property and equipment is comprised of the following:

	December 31, 2017	December 31, 2016
	(In thousands)	
Proved oil and natural gas properties	$ 423,611	$ 258,530
Unproved oil and natural gas properties	121,690	1,942
Land	406	1,561
Less: accumulated DD&A	(114,375)	(139,766)
Total oil and natural gas properties (successful efforts), net	431,332	122,267
Other property and equipment	4,345	3,808
Less: accumulated DD&A	(3,062)	(2,702)
Total other property and equipment	1,283	1,106
Total property and equipment, net	$ 432,615	$ 123,373

As the Company's exploration and development work progresses and the reserves on the Company's properties are proven, capitalized costs attributed to the properties and mineral interests are subject to DD&A. Depletion of capitalized costs is provided using the units-of-production method based on proved oil and gas reserves related to the associated field. DD&A expense related to oil and natural gas properties was $35.4 million, $24.4 million, and $22.8 million for the years ended December 31, 2017, 2016 and 2015, respectively. Depreciation and amortization expense related to other property and equipment was $0.4 million for each of the years ended December 31, 2017, 2016 and 2015.

Costs not subject to DD&A primarily include leasehold costs, broker and legal expenses and capitalized internal costs associated with developing oil and natural gas prospects on these properties. Leasehold costs are transferred into costs subject to depletion on an ongoing basis as these properties are evaluated and proved reserves are established. Additionally, costs associated with development wells in progress or awaiting completion at year-end are not subject to DD&A. These costs are transferred into costs subject to DD&A on an ongoing basis as these wells are completed and proved reserves are established or confirmed. These capitalized costs totaled $57.2 million at December 31, 2017 and $10 million at December 31, 2016.

Impairment charges related to proved and unproved oil and natural gas properties were $1.1 million and no impairment charges for the years ended December 31, 2017 and 2016, respectively. There were no exploratory well costs pending determination of proved reserves for the years ended December 31, 2017 or 2016. Unsuccessful exploratory dry hole costs were $0.2 million for the year ended December 31, 2017. There were no unsuccessful exploratory well costs during the year ended December 31, 2016.

Note 7 – Accrued Liabilities and Other

Accrued liabilities and other is comprised of the following as of the respective dates:

	December 31, 2017	December 31, 2016
	(In thousands)	
Accrued payroll	$ 2,352	$ 948
Accrued legal and professional fees	340	223
Accrued insurance	153	—
Production taxes	147	120
Royalties payable	3,903	2,494
Advances from joint owners	113	219
Asset retirement obligations, current	108	251
Accrued lease operating expense	2,230	—
Series B Preferred Stock dividends payable	937	—
Contingent liability - White Wolf Acquisition	4,005	—
Other	1,204	399
Total accrued liabilities and other	$ 15,492	$ 4,654

Note 8 – Long term debt, net

The Company's debt is comprised of the following:

	December 31, 2017	December 31, 2016
	(In thousands)	
Revolving Credit Facility	$ —	$ 55,000
Second Lien Notes	100,000	—
Total Debt	100,000	55,000
Debt issuance cost on Second Lien Notes, net	3,830	—
Discount on Second Lien Notes, net	2,971	—
Total debt issuance cost and discounts	$ 6,801	$ —
Total long-term debt, net	$ 93,199	$ 55,000

Revolving Credit Facility

On April 27, 2017, Rosehill Operating and PNC Bank, National Association, as lender, Administrative Agent and Issuing Bank, and each of the lenders from time to time party thereto (collectively, the “Lenders”) entered into a credit agreement, which provides Rosehill Operating with a revolving line of credit and a letter of credit facility of up to $250 million (the "Credit Agreement”), subject to a borrowing base that is determined semi-annually by the Lenders based upon Rosehill Operating’s financial statements and the estimated value of its oil and gas properties, in accordance with the Lenders’ customary practices for oil and gas loans. Such redetermined borrowing base will become effective and applicable to Rosehill Operating and the Lenders on or about April 1st and October 1st of each year, as applicable, and commenced on October 1, 2017. Rosehill Operating and the Lenders may each request an additional redetermination of the borrowing base once between two successive scheduled redeterminations. The borrowing base will be automatically reduced upon the issuance or incurrence of debt under senior unsecured notes or upon Rosehill Operating’s or any of its subsidiary’s disposition of properties or liquidation of hedges in excess of certain thresholds. Amounts borrowed under the Credit Agreement may not exceed the borrowing base. Rosehill Operating’s initial borrowing base was $55 million, which was increased to $75 million on October 30, 2017. The Credit Agreement also does not permit Rosehill Operating to borrow funds, if at the time of such borrowing, Rosehill Operating is not in pro forma compliance with the financial covenants. Additionally, Rosehill Operating's borrowing base may be reduced in connection with the subsequent redetermination of the borrowing base. The amounts outstanding under the Credit Agreement are secured by first priority liens on substantially all of Rosehill Operating's oil and natural gas properties and associated assets and all of the stock of Rosehill Operating's material operating subsidiaries that are guarantors of the Credit Agreement. If an event of default occurs under the Credit Agreement, the Lenders have the right to proceed against the pledged capital stock and take control of substantially all of Rosehill Operating and Rosehill Operating's material operating subsidiaries that are guarantors' assets.

Borrowings under the Credit Agreement will bear interest at a base rate plus an applicable margin ranging from 1.00% to 2.00% or at London Interbank Offered Rate ("LIBOR") plus an applicable margin ranging from 2.00% to 3.00%. The Credit Agreement matures on April 27, 2022. There were no amounts outstanding under the Credit Agreement as of December 31, 2017.

The Credit Agreement contains various affirmative and negative covenants. These covenants may limit Rosehill Operating's ability to, among other things: incur additional indebtedness; make loans to others; make investments; enter into mergers; make or declare dividends or distributions; enter into commodity hedges exceeding a specified percentage of Rosehill Operating's expected production; enter into interest rate hedges exceeding a specified percentage of Rosehill Operating's outstanding indebtedness; incur liens; sell assets; and engage in certain other transactions without the prior consent of the Lenders.

The Credit Agreement also requires Rosehill Operating to maintain the following financial ratios: (1) a working capital ratio, which is the ratio of consolidated current assets (including unused commitments under the Credit Agreement, but excluding non-cash assets) to consolidated current liabilities (excluding non-cash obligations, reclamation obligations to the extent classified as current liabilities and current maturities under the Credit Agreement), of not less than 1.0 to 1.0; (2) a leverage ratio, which is the ratio of the sum of all of Rosehill Operating's Total Funded Debt to EBITDAX (as such terms are defined in the Credit Agreement) for the four fiscal quarters then ended, of not greater than 4.00 to 1.00. The Company was in compliance with the financial covenants in the Credit Agreement for the measurement period ended December 31, 2017.

On March 28, 2018, the Company entered into an Amended and Restated Credit Agreement (the "New Credit Agreement") by and among the Company, as borrower, JPMorgan Chase Bank, N.A., as administrative agent, and certain other financial institutions party thereto, as lenders. The New Credit Agreement will bear interest at an adjusted base rate plus an applicable margin ranging from 1.00% to 2.00% or at an adjusted LIBO Rate plus an applicable margin ranging from 2.00% to 3.00%. The New Credit Agreement amends and restates in its entirety the original Credit Agreement entered into on April 27, 2017 and amended on December 8, 2017. Pursuant to the New Credit Agreement, the lenders party thereto have agreed to provide the Company with a $500 million secured reserve-based revolving credit facility with a current borrowing base of $150 million. The maturity date of the New Credit Agreement is August 31, 2022 and automatically extended to March 2023 upon the payment in full of the Second Lien Notes. The borrowing base will be redetermined semi-annually, with the lenders and the Company each having the right to one interim unscheduled redetermination between any two consecutive semi-annual redeterminations. The first scheduled redetermination date is August 1, 2018 and then beginning in 2019 each April 1 and October 1 thereafter.

Second Lien Notes

On December 8, 2017, Rosehill Operating issued and sold $100,000,000 in aggregate principal amount of 10.00% Senior Secured Second Lien Notes due January 31, 2023 (the "Second Lien Notes") to EIG under and pursuant to the terms of that certain Note Purchase Agreement, dated as of December 8, 2017 (the "Note Purchase Agreement"), among Rosehill Operating, the Company, the holders of Notes party thereto (the "Holders") and U.S. Bank National Association, as agent and collateral agent on behalf of the Holders (the "Agent"). The Notes were issued and sold to the Holders in a private placement exempt from the registration requirements under the Securities Act (such issuance and sale, the "Notes Purchase").

Under the Note Purchase Agreement, Rosehill Operating may, at its option, redeem the Second Lien Notes in whole or in part, together with accrued and unpaid interest thereon, (i) at any time after December 8, 2019 but on or prior to December 8, 2020, at a redemption price equal to 103% of the principal amount of the Notes being redeemed, (ii) at any time after December

8, 2020 but on or prior to December 8, 2021, at a redemption price equal to 101.5% of the principal amount of the Notes being redeemed and (iii) at any time after December 8, 2021, at a redemption price equal to the principal amount of the Notes being redeemed. On or prior to December 8, 2019, Rosehill Operating may, at its option, redeem the Second Lien Notes in whole or in part, together with accrued and unpaid interest thereon, at a redemption price equal to 103% of the principal amount of the Second Lien Notes being redeemed plus an additional make-whole premium set forth in the Note Purchase Agreement.

The Second Lien Notes may become subject to redemption under certain other circumstances, including upon the incurrence of non-permitted debt or, subject to various exceptions, reinvestments rights and prepayment or redemption rights with respect to other debt or equity of Rosehill Operating, upon an asset sale, hedge termination or casualty event. Rosehill Operating will be further required to make an offer to redeem the Second Lien Notes upon a Change in Control (as defined in the Note Purchase Agreement) at a redemption price equal to 101% of the principal amount being redeemed. Other than in connection with a change in control or casualty event, the redemption prices and make-whole premium described in the foregoing paragraph shall also apply, at such times and to the extent set forth therein, to any mandatory redemption of the Second Lien Notes or any acceleration of the Second Lien Notes prior to the stated maturity thereof upon the occurrence of an event of default.

The Note Purchase Agreement requires Rosehill Operating to maintain a leverage ratio, which is the ratio of the sum of all of Rosehill Operating's Total Funded Debt to EBITDAX (as such terms are defined in the Note Purchase Agreement) for the four fiscal quarters then ended, of not greater than 4.00 to 1.00.

The Note Purchase Agreement contains various affirmative and negative covenants, events of default and other terms and provisions that are based largely on the existing first-lien revolving credit facility of Rosehill Operating, with a number of important modifications reflecting the second lien nature of the Second Lien Notes and certain other terms that were agreed with the Holders. The negative covenants may limit Rosehill Operating's ability to, among other things, incur additional indebtedness (including under senior unsecured notes), make investments, make or declare dividends or distributions, redeem its preferred equity, acquire or dispose of oil and gas properties and other assets or engage in certain other transactions without the prior consent of the Holders, subject to various exceptions, qualifications and value thresholds. Rosehill Operating is also required to meet minimum commodity hedging levels based on its expected production within a certain post-closing period and on an ongoing basis.

The Company is subject to certain limited restrictions under the Note Purchase Agreement, including (without limitation) a negative pledge with respect to its equity interests in Rosehill Operating and a contingent obligation to guarantee the Notes upon request by the Holders in the event that the Company incurs debt obligations.

The obligations of Rosehill Operating under the Note Purchase Agreement are secured on a second-lien basis by the same collateral that secures its first-lien obligations. In connection with the Notes Purchase, Rosehill Operating has granted first-lien and second-lien security interests over additional collateral to meet the minimum mortgage requirements under the Note Purchase Agreement.

The Company was in compliance with the financial covenants in the Note Purchase Agreement for the measurement period ended December 31, 2017.

Tema Credit Agreement

In December 2012, Tema entered into a secured line of credit with a bank for $60 million (the "Tema Credit Agreement"), with an optional expansion to $75 million, subject to satisfactory credit underwriting. Borrowings under the Tema Credit Agreement bore interest at floating LIBOR plus 1.00% (the Applicable Margin), and was collateralized by the existing producing oil and natural gas properties. There was no principal amortization required until the expiration of the Tema Credit Agreement, when all outstanding amounts became due.

Upon the closing of the Transaction on April 27, 2017, the $55 million outstanding balance under the Tema Credit Agreement was assumed by Rosehill Operating and immediately paid off using proceeds from the issuance of preferred stock in the Transaction. Concurrent with the initial draw down of the Tema Credit Agreement, an interest rate swap was entered into with a bank to fix the interest rate of the Tema Credit Agreement. In anticipation of the closing of the Transaction on April 20, 2017, the interest rate swap was terminated.

Debt Maturities

The following are maturities of long-term debt for each of the next five years and thereafter (amounts in thousands):

2018	$	—
2019		—
2020		—
2021		—
2022		—
Thereafter		100,000
Total	$	100,000

Deferred Financing Costs and Debt discount

The Company capitalizes discounts and certain direct costs associated with the issuance of debt and amortizes such costs over the lives of the respective debt instruments. The Company amortized debt issuance costs and discounts of $0.3 million, $0.1 million, and $0.1 million for the years ended December 31, 2017, 2016, and 2015, respectively. The deferred financing costs related to the revolving credit facility are classified in prepaid assets and the deferred financing costs and discounts related to the Second lien notes are netted against the long-term debt. The following table summarizes the Company's deferred financing costs and debt discounts:

	December 31,			
	2017		2016	
	(In thousands)			
Revolving credit facility				
Debt issuance costs	$	1,219	$	447
Accumulated amortization of debt issuance costs		(541)		(334)
Net deferred costs - Revolving credit facility		678		113
Second lien notes				
Debt discount		3,000		—
Accumulated amortization of debt discount		(29)		—
Debt issuance costs		3,868		—
Accumulated amortization of debt issuance costs		(38)		—
Net deferred costs - Second lien notes		6,801		—
Total net deferred financing costs and debt discount	$	7,479	$	113

Note 9 – Asset Retirement Obligations

The following table summarizes the changes in the Company's asset retirement obligation for the periods below:

	Year Ended December 31, 2017	Year Ended December 31, 2016
	(In thousands)	
Asset retirement obligations, beginning of period	$ 5,431	$ 3,667
Additional liabilities incurred	5,389	164
Dispositions	(2,380)	—
Accretion expense	317	176
Liabilities settled upon plugging and abandoning wells	(504)	(53)
Revision of estimates	377	1,477
Asset retirement obligations, end of period	8,630	5,431
Less: current portion of asset retirement obligations	(108)	(251)
Long-term asset retirement obligations	$ 8,522	$ 5,180

Note 10 - 10% Series B Redeemable Preferred Stock

On December 8, 2017, in connection with the White Wolf Acquisition, see Note 3 - *Acquisitions and Divestitures*, the Company entered into a Series B Redeemable Preferred Stock Purchase Agreement (the "Series B Preferred Stock Agreement") to issue 150,000 shares of the Company's 10.00% Series B Redeemable Preferred Stock (the "Series B Preferred Stock"), par value of $0.0001 per share, for an aggregate purchase price of $150.0 million, less transaction costs, advisory and up-front fees of approximately $10.0 million to certain private funds and accounts managed by EIG Global Energy Partners, LLC (collectively, the "Series B Preferred Stock Purchasers"). The Company has the option, subject to certain conditions, to sell from time to time up to an additional 50,000 shares of Series B Preferred Stock, in aggregate, to the Series B Preferred Stock Purchasers and their transferees for a purchase price of $1,000 per share of Series B Preferred Stock. Such option terminates on December 8, 2018.

Holders of the Series B Preferred Stock are entitled to receive, when, as and if declared by the Board of Directors of the Company (the "Board"), cumulative dividends in cash, at a rate of 10.00% per annum on the $1,000 liquidation preference per share of Series B Preferred Stock, payable quarterly in arrears on January 15, April 15, July 15 and October 15 of each year, commencing on January 15, 2018. With respect to dividends declared for any quarter ending on or prior to January 15, 2019, the Company may elect to pay as dividends additional shares of Series B Preferred Stock in kind (the "Series B PIK Shares") in an amount up to 40% of that which would have been payable had the dividends been fully paid in cash. On December 29, 2017, the Board declared a dividend that was paid 40% in-kind with Series B Preferred Shares, and 60% in cash on January 16, 2018.

Holders of the Series B Preferred Stock have no voting rights and have limited consent rights with respect to the taking of certain corporate actions by the Company. Upon the Company's voluntary or involuntary liquidation, winding-up or dissolution, each holder of Series B Preferred Stock will be entitled to receive the Base Return Amount (as defined in the Series B Preferred Stock Agreement) plus accrued and unpaid dividends.

The shares of Series B Preferred Stock are redeemable by the Company at the election of the holders on or after December 8, 2023, and upon certain conditions, and at any time at the Company's option. As the Series B Preferred Stock holders have an option to redeem the Series B Preferred Stock at a future date, the proceeds from the Series B Preferred Stock have been included in temporary, or "mezzanine" equity, between total liabilities and stockholders' equity / parent net investment on the consolidated balance sheets. The Series B Preferred Stock, while not currently redeemable at the option of the holders, are considered probable of becoming redeemable and therefore will be subsequently remeasured each reporting period by accreting the initial value to the estimated redemption date of December 8, 2023 when the Series B Preferred Stock are redeemable in whole or in part at the election of the Series B Preferred Stock holders. The accretion is presented as a deemed dividend and recorded in mezzanine equity on the consolidated balance sheets and within preferred dividends on the consolidated statements of operations.

In addition to the 10.00% per annum cumulative dividend holders of the Series B Preferred Stock are entitled to receive, upon redemption of the Series B Preferred Stock, such holders are guaranteed a base return on the initial 150,000 shares purchased in an amount equal to (1) $1,250 per share of Series B Preferred Stock times the number of outstanding shares of Series B Preferred Stock if the Company redeems the shares prior to the first anniversary of the date of issuance of such share of Series B Preferred Stock; (2) $1,350 per share of Series B Preferred Stock times the number of outstanding shares of Series B Preferred Stock if the Company redeems the shares on or after the first anniversary and prior to the second anniversary of the date of issuance of such share of Series B Preferred Stock; and (3) on or after the second anniversary of the date of issuance of such share of Series B Preferred Stock, the greater of (x) $1,500 per share of Series B Preferred Stock and (y) an amount necessary to achieve a 16% internal rate of return ("IRR") (the "Base Return Amount") with respect to such shares of Series B Preferred Stock. Since the Series B Preferred Stock can be redeemed by the holders on or after December 23, 2023 and management has no plans to redeem before that date, the Company has accrued a guaranteed return amount in order to achieve the 16% IRR.

In the event of a change of control, the Company shall redeem in cash all of the outstanding shares of Series B Preferred Stock, excluding Series B PIK Shares, for a price per share equal to the Base Return Amount and all Series B PIK Shares at the purchase price of $1,000 per share. The Company assessed the change of control feature and determined that the redemption of the outstanding shares of Series B Preferred Stock, excluding Series B PIK Shares, for a price per share equal to the Base Return Amount was an embedded derivative that requires bifurcation and shall be accounted for at fair value. The Company measured the derivative liability and recorded a discount of $0.6 million upon initial measurement. The accretion of the discount is presented within preferred dividends on the consolidated statement of operations.

The Company reflected the following in mezzanine equity for the Series B Preferred Stock as of December 31, 2017:

	Series B Preferred Shares	Series B Preferred Stock	Guaranteed Return	Total
		(In thousands, except shares)		
Issuance of Series B Preferred Stock	150,000	$ 150,000	$ —	$ 150,000
Discount - upfront fees	—	(4,000)	—	(4,000)
Discount - transaction costs	—	(6,017)	—	(6,017)
Discount - bifurcated derivative	—	(625)	—	(625)
Net Proceeds	150,000	139,358	—	139,358
Return (16% IRR)	—	—	2,273	2,273
Dividends declared and payable in cash	—	—	(937)	(937)
Dividends declared and paid-in-kind	626	626	(626)	—
Accretion of Discount - deemed dividend	—	174	—	174
Total Series B Preferred Stock	150,626	$ 140,158	$ 710	$ 140,868

In March 2018, the Company's Board of Directors declared an additional dividend of $24.66 per share on the Series B Preferred Stock, of which 60%, or approximately $2.2 million will be paid in cash and 40%, or approximately $1.5 million will be paid in kind through the issuance of 1,486 shares of Series B Preferred Stock. The dividends were paid on April 16, 2018.

Note 11 – Stockholders' Equity / Parent Net Investment

The following description summarizes the material terms and provisions of the securities that the Company has authorized. Prior to the Transaction, KLRE was a shell company with no operations, formed as a vehicle to effect a business combination with one or more operating businesses. After the closing of the Transaction, the Company became a holding company whose sole material asset is its interest in Rosehill Operating. The following table summarizes the changes in the outstanding preferred stock, common stock and Class A common warrants exercisable for shares of Class A Common Stock through the date of the Transaction.

	Series A Preferred Stock	Class A Common Stock	Class B Common Stock	Class F Common Stock	Total Shares of Common Stock	Class A Common Stock Warrants
Issued at formation	—	588,276	—	4,312,500	4,900,776	588,276
Issued at IPO	—	7,597,044	—	—	7,597,044	7,597,044
Issued in connection with private placement	—	—	—	—	—	8,408,838
Forfeitures/Cancellation of founder shares	—	—	—	(2,266,170)	(2,266,170)	—
Conversion of founder shares	—	3,475,665	—	(2,046,330)	1,429,335	—
Redemption of Class A shares	—	(5,804,404)	—	—	(5,804,404)	—
Issued to Tema in connection with the Transaction	—	—	29,807,692	—	29,807,692	4,000,000
Preferred stock and warrants issued to PIPE Investors	75,000	—	—	—	—	5,000,000
Preferred stock issued to KLR Sponsor and Rosemore Holdings, Inc.	20,000	—	—	—	—	—
Outstanding at the Transaction date	95,000	5,856,581	29,807,692	—	35,664,273	25,594,158

Class A Common Stock. Holders of the Class A Common Stock are entitled to one vote for each share held on all matters to be voted on by the stockholders. Holders of the Class A Common Stock and holders of the Class B Common Stock voting together as a single class, have the exclusive right to vote for the election of directors and on all other matters properly submitted to a vote of the stockholders. Additionally, KLR Sponsor and Tema agreed to restrictions on certain transfers of the Company's securities, which include, subject to certain exceptions, restrictions on the transfer of (i) 33% of their Common Stock through the first anniversary of the closing date of the Transaction and (ii) 67% of their common stock through the second anniversary of the closing date, provided that sales of common stock above $18.00 per share will be permitted between the first and second anniversaries of the closing date of the Transaction. Further, in connection with underwritten offerings by KLR Sponsor and Tema, and subject to certain conditions, sales of common stock at a price reasonably expected to equal or exceed $18.00 per share and in any case equal to or in excess of $16.00 per share will be permitted.

In connection with the Transaction, the Company distributed approximately $60.6 million of the cash proceeds from the Company's initial public offering to redeem 5.8 million shares of Class A Common Stock, which shares were then cancelled by the Company. Cash transferred to Rosehill Operating, net of transaction expenses incurred in connection with the Transaction, was $18.7 million.

Class B Common Stock. Shares of Class B Common Stock may be issued only to Tema, their respective successors and assignees, as well as any permitted transferees of Tema. A holder of Class B Common Stock may transfer shares of Class B Common Stock to any transferee (other than the Company) only if such holder also simultaneously transfers an equal number of such holder's Rosehill Operating Common Units to such transferee in compliance with the LLC Agreement. Holders of the Class B Common Stock will vote together as a single class with holders of the Class A Common Stock on all matters properly submitted to a vote of the stockholders.

Holders of Class B Common Stock, generally have the right to cause the Company to redeem all or a portion of their stock in exchange for shares of the Company's Class A Common Stock on a one-to-one basis or, at the Company's option, an equivalent amount of cash. The Company may, however, at its option, affect a direct exchange of cash or Class A Common Stock for such Rosehill Operating Common Units in lieu of such a redemption. Upon the future redemption or exchange of Rosehill Operating Common Units, a corresponding number of shares of Class B Common Stock will be canceled.

In the Transaction, the Company issued to Rosehill Operating 29,807,692 shares of its Class B Common Stock and 4,000,000 warrants exercisable for shares of its Class A Common Stock in exchange for 4,000,000 warrants exercisable for Rosehill Operating Common Units. Rosehill Operating immediately distributed the warrants and shares of Class B Common Stock to Tema.

Class F Common Stock. In November 2015, pursuant to the Securities Subscription Agreement, dated as of November 20, 2015, KLR Sponsor purchased 4,312,500 shares of Class F Common Stock (the "Founder Shares") for $25,000. The Founder Shares were identical to the Class A Common Stock included in the units sold in its initial public offering ("IPO") except that the Founder Shares were subject to certain transfer restrictions. In December 2015, February 2016 and March 2016, KLR Sponsor and the Company's officers returned an aggregate of 575,000; 862,500; and 828,670 Founder Shares, respectively, at no cost. All of the Founder Shares returned were canceled by the Company.

The 2,046,330 remaining Founder Shares represented 20.0% of the outstanding shares upon the completion of the IPO. On April 28, 2017, all of the outstanding Founder Shares were automatically converted into 3,475,665 shares of Class A Common Stock in connection with the Transaction. As used herein, unless the context otherwise requires, the "Founder Shares" are deemed to include the shares of Class A Common Stock issued upon conversion of the Founder Shares and such converted shares continue to be subject to certain transfer restrictions.

8% Series A Cumulative Perpetual Convertible Preferred Stock. Each share of Series A Preferred Stock has a liquidation preference of $1,000 per share and is convertible, at the holder's option at any time, initially into 86.9565 shares of the Company's Class A Common Stock (which is equivalent to an initial conversion price of approximately $11.50 per share of Class A Common Stock), subject to specified adjustments and limitations as set forth in the Certificate of Designations of Series A Preferred Stock (the "Certificate of Designations"). Under certain circumstances, the Company will increase the conversion rate upon a "fundamental change" as described in the Certificate of Designations. Based on the initial conversion rate, 8,495,476 shares of the Company's Class A Common Stock would be issuable upon conversion of all of the Series A Preferred Stock outstanding at December 31, 2017.

The Company contributed the net proceeds of $70.8 million ($75 million gross proceeds, net of $4.2 million in issuance costs) from its issuance of 75,000 shares of Series A Preferred Stock and 5,000,000 warrants exercisable for shares of Class A Common Stock to Rosehill Operating. In connection with the issuance of the Series A Preferred Stock, KLR Sponsor transferred 476,540 of its Class A common shares to the PIPE Investors to consummate the Transaction. The net proceeds from the issuance of these preferred shares and warrants was attributed to the preferred stock, warrants and Class A shares contributed by KLR Sponsor issued to the PIPE Investors based on the relative fair value of those securities using, among other factors, the closing price of the Class A Common Stock and the closing price of the warrants on April 27, 2017.

The nondetachable conversion option embedded in the Series A Preferred Stock was evaluated pursuant to ASC 470-20 to determine whether a beneficial conversion feature existed as of the closing date of the Transaction which would be recognized separately from the Series A Preferred Stock in the Company's consolidated financial statements. The conversion option is considered beneficial if, at the commitment closing date, the effective conversion price (represented by the proceeds received less the allocated value of the warrants exercisable for shares of Class A Common Stock and Class A Common Stock) for the Series A Preferred Stock is less than the fair value of the Class A Common Stock into which it is convertible at the commitment closing date. As a result of this evaluation, the Company separately recognized in additional paid-in-capital, with an offsetting reduction in the carrying amount of the Series A Preferred Stock, the value of the beneficial conversion feature at the commitment date of $6.7 million. Since the Company's Series A Preferred Stock is perpetual and has no stated maturity date and no restrictions on conversion, the value attributable to the nondetachable conversion option was recognized immediately as a non-cash deemed dividend on the date that the Series A Preferred Stock was issued. Future issuances of Series A Preferred Stock resulting from dividends paid-in-kind may, depending on the trading price per share of the Company's Class A Common Stock on the dividend date, contain a beneficial conversion option determined on the same basis as described above and, thus, result in additional non-cash deemed dividends which will reduce net income attributable to Rosehill Resources, Inc. common stockholders when such paid-in-kind preferred shares are granted.

The Company also ratably recognizes additional non-cash deemed dividends attributable to the Series A Preferred Stock discount which was created by the issuance of the warrants exercisable for shares of Class A Common Stock and the contribution of the Class A Common Stock, as the Series A Preferred Stock which was sold to the PIPE Investors is converted. During the fourth quarter of 2017 PIPE Investors converted 2,832 shares of Series A Preferred Stock to 246,264 shares of Class A Common Stock based at the conversion rate discussed above. In connection with this conversion, the Company recognized additional deemed dividends of $0.7 million. These and future non-cash deemed dividends will, upon Series A Preferred Stock conversions, reduce net income attributable to Rosehill Resources Inc, common stockholders.

The table below summarizes the preferred stock dividends reflected in the Company's consolidated statements of operations for the year ended December 31, 2017 (in thousands):

Series A Preferred Stock paid-in-kind	$	5,530
Series A Preferred Stock paid in cash		38
Series A Preferred Stock dividends		5,568
Deemed dividend related to beneficial conversion feature		6,700
Deemed dividend related to conversion to Class A Common Stock		668
Series A Preferred Stock dividends and deemed dividends	$	12,936

Rosemore and KLR Sponsor backstopped redemptions by the public stockholders of the Company once 30% of the outstanding shares of Class A Common Stock were redeemed by purchasing 20,000 shares of Series A Preferred Stock for net proceeds of $20 million pursuant to a side letter entered into between Rosemore, KLR Sponsor and the Company.

The Company contributed to Rosehill Operating the net proceeds from the issuance of 20,000 shares of Series A Preferred Stock to Rosemore Holdings, Inc. and KLR Sponsor.

The Company’s Board of Directors declared dividends on the Series A Preferred Stock on June 29, 2017, September 29, 2017, and December 29, 2017 totaling $5.6 million, which dividends were primarily paid in-kind through the issuance of 1,372, 1,926, and 2,232 shares of Series A Preferred Stock on July 15, 2017, October 16, 2017, and January 16, 2018 respectively.

In March 2018, the Company's Board of Directors declared an additional dividend of $19.73 per share on the Series A Preferred Stock, of which 50%, or approximately $1.0 million will be paid in cash and 50%, or approximately $1.0 million will be paid in kind through the issuance of 964 shares of Series A Preferred Stock. The dividends were paid on April 16, 2018

Warrants. Each of the Company’s warrants entitles the registered holder to purchase one share of the Company’s Class A Common Stock at a price of $11.50 per share, subject to adjustment pursuant the terms of the warrant agreement. The warrants have a five-year term which commenced on April 27, 2017, upon the completion of the Transaction and will expire on April 27, 2022. The Company may call the warrants for redemption if the reported last sale price of the Class A Common Stock equals or exceeds $21.00 per share for any 20 trading days within a 30-trading day period ending on the third trading day prior to the date the Company sends the notice of redemption to the warrant holders.

There were 588,276 warrants issued in connection with the formation of the Company and 7,597,044 public warrants issued in connection with KLRE’s IPO. Additionally, there were 8,408,838 warrants issued to KLR Sponsor and EarlyBirdCapital Inc.

pursuant to a private placement (the "Private Placement Warrants") in connection with the Company's initial public offering (including the Class A Common Stock issuable upon exercise of the Private Placement Warrants). The Private Placement Warrants will not be redeemable by the Company and will be exercisable on a cashless basis so long as they are held by the initial holders or their permitted transferees. Otherwise, the Private Placement Warrants have terms and provisions that are identical to those of the warrants described above. If the Private Placement Warrants are held by holders other than the initial holders or their permitted transferees, the Private Placement Warrants will be redeemable by the Company and exercisable by the holders on the same basis as the warrants described above.

In connection with the closing of the Transaction, the Company issued 5,000,000 warrants to the PIPE Investors and 4,000,000 warrants to Tema. These warrants were issued on the same terms, and are subject to the same rights and obligations, as described above.

As of December 31, 2017, there were 25,594,158 warrants exercisable for shares of Class A Common Stock outstanding at a price of $11.50. All warrants will expire on April 27, 2022.

Noncontrolling Interest. Noncontrolling interest represents the membership interest held by holders other than the Company. On April 27, 2017, upon the closing of the Transaction, the Company's noncontrolling interest percentage in Rosehill Operating, held by Tema, was approximately 84%. Pursuant to the operating agreement the common members will absorb transaction costs incurred in connection with the equity transactions impacting Rosehill Operating. The Company has consolidated the financial position and results of operations of Rosehill Operating and reflected the proportionate interest held by Tema as a noncontrolling interest. Of the proceeds received in connection with the Transaction, $40.5 million was distributed to the noncontrolling interest. The final working capital adjustment of $2.4 million due to the Company from Tema was reflected as a reduction to the initial distribution to the noncontrolling interest. The non-controlling interest will change when shares of Series A Preferred stock are converted into shares of Class A Common Stock, when shares of Class A Common Stock is issued in connection with the Company's long-term incentive compensation plan and when Tema elects to exchange the Class B Common Stock received in connection with the transaction for shares of our Class A Common Stock. At December 31, 2017 Tema held an approximate 83% noncontrolling interest in Rosehill Operating. During the quarter ended December 31, 2017, the Company recorded an adjustment for the impact of transactions affecting noncontrolling interest of $9.6 million primarily to reflect the change in Tema's ownership interest and transaction costs related to the issuance of preferred units issued by Rosehill Operating. Approximately $3.5 million of that amount relates to an immaterial out of period effect of transaction costs related to the issuance of Series A preferred units in conjunction with the Transaction during the quarter ended June 30, 2017.

Note 12 - Stock Based Compensation

Long-Term Incentive Plan

On April 27, 2017, the stockholders of the Company approved the Rosehill Resources Inc. Long-Term Incentive Plan (the "LTIP"), which permits the grant of a number of different types of equity, equity-based, and cash awards to employees, directors and consultants including grant options, SARs, restricted stock, restricted stock units, stock awards, dividend equivalents, other stock-based awards, substitute awards, performance awards, or any combination of the foregoing, as determined by the Compensation Committee of the Board of Directors (the "Compensation Committee"), in its sole discretion. The purpose of the LTIP is to provide a means to attract and retain qualified service providers by affording such individuals a means to acquire and maintain stock ownership or awards, the value of which is tied to the performance of the Company. The LTIP also provides additional incentives and reward opportunities designed to strengthen such individuals' concern for the welfare of the Company and their desire to remain in its employ. At the plan's inception, 7,500,000 shares of Class A Common Stock were available for issuance under the LTIP.

The following table reflects stock based compensation expense recorded for each type of stock based compensation award for the period indicated:

	Year ended December 31, 2017
	(In thousands)
Restricted stock	$ 385
Restricted stock units	723
Service stock awards	136
Total	$ 1,245

Stock based compensation expense for restricted stock and restricted stock units is recognized on a straight-line basis over the requisite service period for each separately vesting portion of the award as if the award was, in-substance, multiple awards. Stock based compensation is included in general and administrative expense on the Company's consolidated statement of operations.

Restricted Stock

On July 19, 2017, a restricted stock grant of 105,666 shares of Class A Common Stock was awarded to the Company's non-employee directors pursuant to the LTIP. These shares will fully vest on July 18, 2018. Restricted stock is subject to restrictions on transfer and are generally subject to a risk of forfeiture if the award recipient is no longer a director of the Company for any reason prior to the lapse of the restriction. Stock based compensation costs totaling $0.8 million associated with this award will be recognized over the one-year vesting period.

The following table sets forth the restricted stock transactions for the year ended December 31, 2017:

	Shares of Restricted Stock	Weighted-Average Grant Date Fair Value
Outstanding at January 1, 2017	—	—
Awards granted	105,666	$ 7.95
Forfeited	—	—
Vested	—	—
Total Restricted Stock December 31, 2017	105,666	$ 7.95

Restricted Stock Units

On November 9, 2017, the Company granted 713,939 restricted stock units under the LTIP to certain of the Company's employees. Except as otherwise provided in the applicable award agreement, the restricted stock units vest in three equal installments on the first three anniversaries of the date of the closing of the Transaction, subject to continued employment through each such vesting date.

Restricted stock units are subject to restrictions on transfer and are generally subject to a risk of forfeiture if the award recipient is no longer an employee of the Company for any reason prior to the lapse of the restriction. Settlement of the restricted stock units will occur upon vesting or upon expiration of the deferral period by delivering a number of shares of Class A Common Stock equal to the number of restricted stock units. Stock-based compensation costs totaling $7.1 million associated with this award will be recognized over the three-year vesting period.

The following table sets forth the restricted stock unit transactions for the year ended December 31, 2017:

	Restricted Stock Units	Weighted-Average Grant Date Fair Value
Outstanding at January 1, 2017	—	—
Awards granted	713,939	$ 9.88
Forfeited	—	—
Vested	—	—
Outstanding at December 31, 2017	713,939	$ 9.88

Service Stock Awards

On November 9, 2017 the Company granted 13,790 fully vested shares of its Class A Common Stock to certain of the Company's employees as a Service Stock Award under the LTIP. Stock based compensation costs totaling $0.1 million associated with these awards were recognized in the year ended December 31, 2017.

The following table reflects the future stock based compensation expense to be recorded for the awards that were outstanding at December 31, 2017:

	Restricted Stock	Restricted Stock Units
	(In thousands)	
2018	$ 455	$ 3,225
2019	—	2,347
2020	—	758
Total	$ 455	$ 6,330

As of December 31, 2017, there were 6,666,605 shares of Class A Common Stock available for issuance under the LTIP, subject to adjustment pursuant to the plan.

Retirement Benefits

The Company has not maintained, and does not currently maintain, a defined benefit pension plan or nonqualified deferred compensation plan. The Company currently maintains a retirement plan pursuant to which employees are permitted to contribute portions of their base compensation to a tax-qualified retirement account. The Company provides matching contributions equal to 100% of elective deferrals up to 3% of eligible compensation and 50% of elective deferrals from 3% to a maximum of 5% of eligible compensation, subject to the applicable contributions limits. Matching contributions are immediately fully vested. The Company matching contributions under the plan totaled $0.1 million for the years ended December 31, 2017 and 2016.

Note 13 – Income Taxes

In 2017, the Company became the sole managing member of Rosehill Operating, the Company’s accounting predecessor. Rosehill Operating is a limited liability company that is treated as a partnership for U.S. federal income tax purposes, and is not subject to U.S. federal income tax. Any taxable income or loss generated by Rosehill Operating is passed through to and included in the taxable income or loss of its members, including the Company. The Company is a C corporation and is subject to U.S. federal income tax and state and local income taxes.

The tax implications of the Transaction, and the tax impact of the Company's status as a taxable C corporation (subject to U.S. federal income tax) have been reflected in the accompanying consolidated financial statements. Total income tax expense differed from amounts computed by applying the U.S. federal statutory tax rates to pre-tax income due primarily to the change in tax status, state taxes and the impact of earnings (loss) attributable to noncontrolling ownership interests.

On December 22, 2017, the U.S. government enacted comprehensive tax legislation through Public Law No. 115-97, commonly referred to as the Tax Cuts and Jobs Act (the "Tax Act"). The provisions of the Tax Act that impact the Company include, but are not limited to, (1) reducing the U.S. federal corporate income tax rate from 35% to 21%; (2) eliminating the corporate alternative minimum tax (AMT); (3) allowing businesses to immediately expense the cost of new investments in certain qualified depreciable assets acquired after September 27, 2017 (with a phase-down of such expensing starting in 2023), (4) reducing the maximum deduction for net operating loss (NOL) carryforwards generated in tax years beginning after December 31, 2017, to 80 percent of a taxpayer's taxable income and (5) imposing additional limits on future deductibility of interest expense and certain executive compensation. In conjunction with the Tax Act, the SEC staff issued Staff Accounting Bulletin No. 118, Income Tax Accounting Implications of the Tax Cuts and Jobs Act (SAB 118), which provides a measurement period that should not extend beyond one year from the Tax Act enactment date for companies to complete the accounting under ASC 740. In accordance with SAB 118, a company must reflect the income tax effects of those aspects of the Act for which the accounting under ASC 740 is complete. To the extent that a company's accounting for certain income tax effects of the Tax Act is incomplete but it is able to determine a reasonable estimate, it must record a provisional estimate in the financial statements. If a company cannot determine a provisional estimate to be included in the financial statements, it should continue to apply ASC 740 on the basis of the provisions of the tax laws that were in effect immediately before the enactment of the Tax Act.

As discussed further below, the Company remeasured its deferred tax assets and liabilities at year-end using the lower 21% rate, resulting in a decrease in net deferred tax assets and our valuation allowance. Aside from the reduction to the U.S. federal corporate income tax rate, the Tax Act is not expected to have a significant current impact to the Company.

The components of income tax expense were as follows for the periods indicated:

	Year Ended December 31,		
	2017	2016	2015
	(In thousands)		
Current:			
State	$ —	$ 148	$ 108
	$ —	$ 148	$ 108
Deferred:			
Federal	$ 1,537	$ —	$ —
State	153	—	—
	1,690	—	—
Income tax expense	$ 1,690	$ 148	$ 108

The effective combined U.S. federal and state income tax rate for the years ended December 31, 2017, 2016 and 2015 was 16%, 1% and 1%, respectively. Both the effective income tax rate and total income tax expense between the periods presented above varied primarily due to U.S. federal income tax from the change in taxable status as a result of the transaction, the impact of income (loss) attributable to noncontrolling interest, impact of tax reform and changes in the valuation allowance.

The following reconciles the income tax expense included in the consolidated statements of operations with the income tax expense that would result from the application of the statutory federal tax rate:

	Year Ended December 31,		
	2017	2016	2015
	(In thousands)		
Loss before income taxes	$ (10,258)	$ (15,041)	$ (14,712)
Income tax expense (benefit) at federal statutory rate	(3,590)	(5,264)	(5,149)
Net loss prior to transaction	(1,545)	5,264	5,149
Net loss before income taxes attributable to noncontrolling interest	6,584	—	—
State income taxes, net of federal benefit	153	148	108
Nondeductible expenses	88	—	—
Effect of change in federal statutory rate	1,941	—	—
Change in valuation allowance	(1,941)	—	—
Income tax expense	$ 1,690	$ 148	$ 108

The change in the U.S. federal corporate income tax rate from 35% to 21% due to the passage of the Tax Act, resulted in the Company generating a deferred tax expense of $1.9 million, along with a corresponding reduction to its valuation allowance. The impact on our deferred tax assets and liabilities may be adjusted in future periods, as an adjustment to income tax expense, in the period in which final amounts are determined. However, the ultimate impact of the Tax Act may differ from the Company's estimates based on its further analysis of the new law and additional regulatory or interpretive guidance that may be issued.

The components of the Company's deferred tax balances were as follows for the periods indicated:

	December 31,	
	2017	2016
	(In thousands)	
Deferred tax assets:		
Deferred stock-based compensation	$ 232	$ —
Net operating loss carryforward	4,350	—
Other	30	—
Total deferred tax assets	4,612	—
Less: Valuation allowance	(2,912)	—
Net deferred tax assets	$ 1,700	$ —
Deferred tax liabilities:		
Investment in Rosehill Operating	$ (1,700)	$ —
State deferred tax liability	(153)	—
Total deferred tax liabilities	(1,853)	—
Net deferred tax liabilities	$ (153)	$ —

The Company paid less than $0.2 million in state income taxes and did not pay U.S. federal income taxes for 2017 and 2016. As of December 31, 2017, the Company had approximately $21 million of U.S. federal net operating loss carryovers, which will begin to expire in 2035. The Company periodically assesses whether it is more likely than not that it will generate sufficient taxable income to realize its deferred tax assets, including net operating loss carry forwards. A valuation allowance for deferred tax assets is recognized when it is more likely than not that some or all of the benefit from the deferred tax asset will not be realized. In making this determination, the Company considers all available positive and negative evidence and makes certain assumptions. The Company considers, among other things, its deferred tax liabilities, the overall business environment, its historical earnings and losses, current industry trends, and its outlook for future years.

Upon closing the Transaction, the Company acquired a portion of the Rosehill Operating Common Units, and a deferred tax asset was recorded relating to the outside basis difference of its investment in Rosehill Operating for $5.7 million with an offsetting effect recorded in additional paid in capital. Due to uncertainties relating to the realization of the deferred tax asset, the Company recorded a full valuation allowance with an offsetting effect recorded in additional paid in capital. During the year ended December 31, 2017, the subsequent recognition of tax benefits resulted in a partial reduction of the valuation allowance of $1.5 million, with an offsetting effect recorded in additional paid in capital. Section 382 of the Internal Revenue Code of 1986, as amended ("IRC"), addresses company ownership changes and specifically limits the utilization of tax benefits generated prior to the Transaction following an ownership change. Upon closing of the Transaction, the Company believes it experienced an ownership change within the meaning of IRC Section 382, and recorded a valuation allowance of $0.2 million and an offsetting effect in additional paid in capital to fully offset these tax benefits.

The Company is subject to the following material taxing jurisdictions: the United States, Texas and New Mexico. As of December 31, 2017, the Company has no current tax years under audit. The Company remains subject to examination for federal income taxes and state income taxes for tax years 2015 through 2017.

The Company has evaluated all tax positions for which the statute of limitations remains open and believes that the material positions taken would more likely than not be sustained upon examination. Therefore, as of December 31, 2017, the Company had not established any reserves for, nor recorded any unrecognized benefits related to, uncertain tax positions. The Company's policy is to recognize interest and penalties related to uncertain tax positions in income tax expense.

Tax Receivable Agreement

In connection with the Transaction, the Company entered into a tax receivable agreement ("Tax Receivable Agreement") with the noncontrolling interest holder, Tema. The Tax Receivable Agreement provides that the Company will pay to Tema 90% of the net cash savings, if any, in U.S. federal, state and local income tax that the Company realizes (or is deemed to realize in certain circumstances) in periods beginning with and after the closing of the Transaction as a result of the following: (i) any tax basis increases in the assets of Rosehill Operating resulting from the distribution to Tema at Transaction date, the shares of Class B Common Stock and Tema warrants and the assumption of Tema liabilities in connection with the Transaction, (ii) the tax basis increases in the assets of Rosehill Operating resulting from a redemption by Rosehill Operating with respect to Tema or (iii) the increase in tax basis or imputed interest attributable to units acquired or deemed acquired by the Company upon an exchange by Tema of Rosehill Operating Common Units for Class A Common Stock or cash, as applicable.

The estimation of liability under the Tax Receivable Agreement is by its nature imprecise and subject to significant assumptions regarding the amount and timing of future taxable income. As of December 31, 2017, our preliminary estimate of the TRA liability resulting from the distribution of the Cash Consideration to Tema in connection with the Transaction was approximately $0.4 million, however, the Company has not been able to determine that future payments under the TRA are likely to occur and therefore has concluded that no recognizable TRA liability has been incurred. To the extent the Company realizes tax benefits in future years, or in the event of a change in future tax rates, this liability may change. The Company does not anticipate it will realize cash savings on its 2017 tax return as a result of tax attributes arising from the Transaction, and therefore does not anticipate a payment under the Tax Receivable Agreement for the 2017 tax year.

The Tax Receivable Agreement liability is recorded based upon projected tax savings, and the actual amount and timing of payments will depend upon a number of factors, including the amount and timing of taxable income generated in the future, changes in future tax rates, the use of loss carryovers, and the portion of the Company's payments constituting imputed interest. If and when Tema exercises its right to cause the Company to redeem all or a portion of its Rosehill Operating Common Units, a liability under the Tax Receivable Agreement relating to such redemption will be recorded. The amount of liability will be based on 90% of the estimated future cash tax savings that the Company will realize as a result of increases in the basis of Rosehill Operating's assets attributed to the Company resulting from such redemption. The amount of the increase in asset basis, the related estimated cash tax savings and the attendant Tax Receivable Agreement liability will depend, in part, on the price of the

Class A Common Stock at the time of the relevant redemption. Due to the uncertainty surrounding the amount and timing of future redemptions of Rosehill Operating Common Units by Tema, the Company does not believe it is appropriate to record additional Tax Receivable Agreement liability until such time that Rosehill Operating Common Units are redeemed for shares of Class A Common Stock or cash.

Note 14 – Earnings Per Share

The Transaction was structured as a reverse recapitalization by which the Company issued stock for the net assets of Rosehill Operating accompanied by a recapitalization. Earnings per share has been recast for all historical periods to reflect the Company's capital structure for all comparative periods.

The following table sets forth the calculation of basic and diluted weighted average shares outstanding and earnings per share for the indicated periods:

	Year Ended December 31,		
	2017	**2016**	**2015**
	(In thousands, except per share data)		
Net Income (Loss) (numerator):			
Basic:			
Net loss attributable to common stockholders of Rosehill Resources Inc.	$ (8,520)	$ (15,189)	$ (14,820)
Diluted:			
Net loss attributable to common stockholders of Rosehill Resources Inc.	$ (8,520)	$ (15,189)	$ (14,820)
Add: Dividends on Series A convertible preferred stock (1)	—	—	—
Net loss attributable to common stockholders of Rosehill Resources Inc. - diluted	$ (8,520)	$ (15,189)	$ (14,820)
Weighted average shares (denominator):			
Weighted average shares – basic	5,945	5,857	5,857
Weighted average shares – diluted	5,945	5,857	5,857
Basic loss per share	$ (1.43)	$ (2.59)	$ (2.53)
Diluted loss per share	$ (1.43)	$ (2.59)	$ (2.53)

(1) Series A Preferred Stock dividend is not added back for diluted EPS because the conversion of the Series A Preferred Stock to Class A Common Stock would be anti-dilutive.

The Company excluded the following common stock equivalents from the computation of diluted earnings per share because the effect of conversion was anti-dilutive as a result of the net loss for the year ended December 31, 2017:

- 8.5 million shares of Class A Common Stock issuable upon conversion of the Company's Series A Preferred Stock,
- 25.6 million warrants convertible into shares of Class A Common Stock, and
- 0.7 million shares of restricted stock units issued to directors and employees.

Note 15 – Related Party Transactions

The Company is not entitled to compensation for its services as managing member of Rosehill Operating. The Company is entitled to reimbursement by Rosehill Operating for any costs, fees or expenses incurred on behalf of Rosehill Operating (including costs of securities offerings not borne directly by members, board of directors' compensation and meeting costs, cost of periodic reports to its stockholders, litigation costs and damages arising from litigation, accounting and legal costs); provided that the Company will not be reimbursed for any of its income tax obligations.

Rosemore. Rosemore provides employee benefits and other administrative services to Rosehill Operating via the Transition Services Agreement (discussed under *Transaction Service Agreement* below) between Rosehill Operating and Tema. During the year ended December 31, 2017 and the year ended December 31, 2016, Rosemore incurred and Tema billed to Rosehill Operating approximately $9.6 million and $6.0 million, respectively, related to these services. Amounts incurred prior to the Transaction have been allocated to Rosehill Operating on the Consolidated Statements of Operations – see "*Cost Allocations*" below. As of December 31, 2017 and December 31, 2016 the payable due to Tema related to these expenses was less than $0.1 million and $0.3 million, respectively. The amount due to Tema at December 31, 2017 is netted against amounts due from Tema under the Transition Service Agreement discussed below.

Gateway Gathering and Marketing ("Gateway"). A portion of Rosehill Operating's oil, natural gas and NGLs is sold to Gateway, a subsidiary of Rosemore. For the years ended December 31, 2017, 2016, and 2015, revenues from production sold to Gateway were approximately $61.3 million, $24.4 million, and $16.8 million, respectively. As of December 31, 2017 and December 31, 2016, the related receivable due from Gateway was approximately $13.6 million and $4.6 million, respectively.

For the years ended December 31, 2017, 2016, and 2015 approximately $1.1 million, $1.4 million, and $0.8 million, respectively, was incurred related to a marketing and gathering agreement with Gateway. As of December 31, 2017 and December 31, 2016, the payable due to Gateway related to this agreement was approximately $0.2 million and $0.3 million, respectively. Certain consulting services are provided to Gateway, and for the years ended December 31, 2017 and 2016, Gateway was invoiced amounts less than $0.1 million related to these services, which were recorded in general and administrative expenses in the accompanying Consolidated Statements of Operations. Certain other general and administrative services are also provided to Gateway, for which Gateway was invoiced approximately $0.1 million and $0.3 million for the years ended December 31, 2017 and December 31, 2016, respectively. As of December 31, 2017 and 2016, the receivable due from Gateway related to these services was less than $0.1 million and approximately $0.3 million, respectively.

Transaction expenses. Under the terms of the Transaction, the Company reimbursed Tema and Rosemore $1.6 million and $2.4 million, respectively, on April 27, 2017, for costs incurred in connection with the Transaction.

Distributions. The LLC Agreement requires Rosehill Operating to make a corresponding cash distribution to the Company at any time a dividend is to be paid by the Company to the holders of its Series A Preferred Stock and Series B Preferred Stock. The LLC Agreement allows for distributions to be made by Rosehill Operating to its members on a pro rata basis in accordance with the number of Rosehill Operating Common Units owned by each member out of funds legally available therefor. The Company expects Rosehill Operating may make distributions out of distributable cash periodically to the extent permitted by the revolving credit facility agreements of Rosehill Operating and necessary to enable the Company to cover its operating expenses and other obligations, as well as to make dividend payments, if any, to the holders of its Class A Common Stock. In addition, the LLC Agreement generally requires Rosehill Operating to make (i) pro rata distributions (in accordance with the number of Rosehill Operating Common Units owned by each member) to its members, including the Company, in an amount at least sufficient to allow the Company to pay its taxes and satisfy its obligations under the Tax Receivable Agreement and (ii) tax advances, which will be repaid upon a redemption, in an amount sufficient to allow each of the members of Rosehill Operating to pay its respective taxes on such holder's allocable share of Rosehill Operating's taxable income after taking into account certain other distributions or payments received by the unitholder from Rosehill Operating or the Company.

Cost Allocations. For periods prior to the Transaction, Tema allocated certain overhead costs associated with general and administrative services, including insurance, professional fees, facilities, information services, human resources and other support departments related to Rosehill Operating. Also included in the cost allocations are costs associated with employees covered under Rosemore's defined benefit plan and long-term incentive compensation plan. Employees of Rosehill Operating no longer participate in either employee benefit plan. Overhead costs allocated were $1.5 million and $6.0 million for the year ended December 31, 2017 and 2016, respectively. Where costs incurred related to Rosehill Operating's assets in the periods prior to the Transaction could not be determined by specific identification, the costs were primarily allocated proportionately on a Boe basis. Management believes the allocations are a reasonable reflection of the utilization of services provided. However, the allocations may not fully reflect the expense that would have been incurred had Rosehill Operating's assets been a stand-alone company during the 2016 periods presented.

Transition Service Agreement. On April 27, 2017 in connection with the closing of the Transaction, the Company entered into a Transition Service Agreement ("TSA") with Tema to provide certain services to each other following the closing of the Transaction. Pursuant to the terms, the Company agreed to provide to Tema (i) operation services for the assets excluded from the Transaction, (ii) divestment assistance, and (iii) office space to Gateway. Tema agreed to provide to the Company (i) human resources and benefits administration, (ii) information technology and telecommunications, (iii) general business insurance, and (iv) legal services. The TSA terminates on October 27, 2018, unless terminated or discontinued earlier in accordance with the terms and condition of the TSA. Amounts due from Tema related to the TSA at December 31, 2017 are less than $0.1 million.

The Transaction Purchase Price Settlement. The working capital adjustment in the Transaction was originally estimated to be $5.6 million and was contributed to Rosehill Operating by the Company upon closing the Transaction. The final working capital adjustment of $2.4 million due to the Company from Tema was reflected as a reduction to the preliminary purchase price as of December 31, 2017.

KLR Group. In September 2017, the Company entered into an advisory agreement with KLR Group (the "Advisory Agreement"), an affiliate of KLR Sponsor, to pay a cash fee in an amount equal to 2.5% of the aggregate funds committed to finance the White Wolf Acquisition. The Company received a commitment of $200 million under the Series B Preferred Stock Agreement and $100 million under the Second Lien Notes to fund the White Wolf Acquisition. The Company paid an advisory fee of $7.5 million to KLR Group.

Note 16 – Commitments and Contingencies

Leases and Other Commitments

The following is a schedule of the Company's future minimum lease payments with commitments that have initial or remaining lease terms in excess of one year as of December 31, 2017:

	2018	2019	2020	2021	2022	Thereafter	Total
				(In thousands)			
Operating lease obligations	$ 1,230	$ 1,213	$ 1,202	$ 1,097	$ 557	$ —	$ 5,299
Capital lease obligations	34	34	3	—	—	—	71
Total	$ 1,264	$ 1,247	$ 1,205	$ 1,097	$ 557	$ —	$ 5,370

Operating lease obligations. The Company leases office space in Houston, Texas and Midland, Texas. The Company recognized rent expense of $1.0 million, $0.7 million, and $0.7 million for the year ended December 31, 2017, 2016, and 2015, respectively. The Company recognizes rent expense on a straight-line basis over the noncancelable lease term. The leases for office space in Houston, Texas and Midland, Texas expire in June 2022 and December 2020, respectively.

Capital lease obligations. The Company leases printers, scanners, and copiers for its office space. The Company's final payment on the leases will be in January 2020.

Rights of Securities Holders. The holders of the Founder Shares, the Series A Preferred Stock, the Private Placement Warrants and unregistered Class A Common Stock were entitled to registration rights pursuant to certain agreements of the Company. In May 2017, the Company filed a registration statement registering the Founder Shares, the Series A Preferred Stock (and any shares of common stock issuable upon conversion of the Series A Preferred Stock), the Private Placement Warrants (and any shares of Class A Common Stock issuable upon the exercise of the Private Placement Warrants), the unregistered Class A

Common Stock and the shares of common stock issuable upon exercise of the outstanding Public Warrants. The registration statement was declared effective on June 19, 2017.

Rosehill Operating Common Unit Redemption Right. The LLC Agreement provides Tema with a redemption right, which entitles Tema to cause Rosehill Operating to redeem, from time to time, all or a portion of its Rosehill Operating Common Units (and a corresponding number of shares of Class B Common Stock) for, at Rosehill Operating's option, newly issued shares of Class A Common Stock on a one-for-one basis or a cash payment equal to the average of the volume-weighted closing price of one share of Class A Common Stock for the twenty trading days prior to the date Tema delivers a notice of redemption for each Rosehill Operating Common Units redeemed (subject to customary adjustments, including for stock splits, stock dividends and reclassifications). In the event of a reclassification event (as defined in the LLC Agreement), the Company as managing member is required to ensure that each Rosehill Operating Common Units (and a corresponding share of Class B Common Stock) is redeemable for the same amount and type of property, securities or cash that a share of Class A Common Stock becomes exchangeable for or converted into as a result of such reclassification event. Upon the exercise of the redemption right, Tema will surrender its Rosehill Operating Common Units (and a corresponding number of shares of Class B Common Stock) to Rosehill Operating and (i) Rosehill Operating shall cancel such Rosehill Operating Common Units and issue to the Company a number of Rosehill Operating Common Units equal to the number of surrendered Rosehill Operating Common Units and (ii) the Company shall cancel the surrendered shares of Class B Common Stock. The LLC Agreement requires that the Company contribute cash or shares of Class A Common Stock to Rosehill Operating in exchange for the issuance to the Company described in clause (i). Rosehill Operating will then distribute such cash or shares of Class A Common Stock to Tema to complete the redemption. Upon the exercise of the redemption right, the Company may, at its option, affect a direct exchange of cash or its Class A Common Stock for such Rosehill Operating Common Units in lieu of such a redemption.

Maintenance of One-to-One Ratios. The LLC Agreement includes provisions intended to ensure that the Company at all times maintains a one-to-one ratio between (a) (i) the number of outstanding shares of Class A Common Stock and (ii) the number of Rosehill Operating Common Units owned by the Company (subject to certain exceptions for certain rights to purchase equity securities of the Company under a "poison pill" or similar shareholder rights plan, if any, certain convertible or exchangeable securities issued under the Company's equity compensation plans and certain equity securities issued pursuant to the Company's equity compensation plans (other than a stock option plan) that are restricted or have not vested thereunder) and (b) (i) the number of other outstanding equity securities of the Company (including the Series A Preferred Stock and the warrants exercisable for shares of Class A Common Stock) and (ii) the number of corresponding outstanding equity securities of Rosehill Operating. These provisions are intended to result in Tema having a voting interest in the Company that is identical to Tema's economic interest in Rosehill Operating.

Contingencies

Legal. In the ordinary course of business, the Company is party to various legal actions, which arise primarily from its activities as operator of oil and natural gas wells. In management's opinion, the outcome of any such currently pending legal actions will not have a material adverse effect on the Company's financial position or results of operation. There is no material litigation, arbitration or governmental proceeding currently pending against the Company or any members of its management team in their capacity as such.

Environmental Matters. Environmental assessments and remediation efforts are conducted at multiple locations, primarily previously owned or operated facilities. Environmental and clean-up costs are accrued when it is both probable that a liability has been incurred and the amount can be reasonably estimated. Accruals for losses from environmental remediation obligations generally are recorded no later than completion of the remediation feasibility study. Estimated costs, which are based upon experience and assessments, are recorded at undiscounted amounts without considering the impact of inflation and are adjusted periodically as additional or new information is available. Environmental assessments and remediation costs for the years ended December 31, 2017, 2016, and 2015 did not have a material adverse effect on the financial condition, results of operations and cash flows.

Supplemental Oil and Natural Gas Disclosures (Unaudited)

The Company's oil and natural gas reserves are attributable solely to properties within the United States.

Capitalized Costs

Aggregate capitalized costs related to oil and natural gas production activities with applicable accumulated depreciation, depletion, amortization and impairment are presented below:

	December 31,	
	2017	2016
	(In thousands)	
Oil and natural gas properties:		
Proved properties	$ 423,611	$ 258,530
Unproved properties	121,690	1,942
Land	406	1,561
Total oil and natural gas properties	545,707	262,033
Less: accumulated depreciation, depletion and amortization	(114,375)	(139,766)
Net Oil and natural gas properties	$ 431,332	$ 122,267

Costs Incurred for Oil and Natural Gas Producing Activities

The following table sets forth the costs incurred in the Company's oil and gas acquisition, exploration, and development activities and includes costs whether capitalized or expensed as well as revisions and additions to the estimated future asset retirement obligation:

	Year Ended December 31,		
	2017	2016	2015
		(In thousands)	
Property acquisition costs:			
Proved properties	$ 6,500	$ 572	$ 1,382
Unproved properties	121,207	—	—
Total property acquisition costs	127,707	572	1,382
Exploration costs	96,547	12,517	4,851
Development costs	126,563	11,143	9,347
Total costs incurred	$ 350,817	$ 24,232	$ 15,580

Results of Oil and Natural Gas Producing Activities

The following table sets forth results of operations for oil and natural gas producing activities for the following periods:

	Year Ended December 31,		
	2017	2016	2015
	(In thousands)		
Revenues:			
Total revenues	$ 76,236	$ 34,645	$ 29,487
Operating expenses:			
Lease operating expense	10,881	4,800	4,582
Production taxes	3,535	1,541	1,311
Gathering and transportation	2,976	2,398	2,094
Depreciation, depletion, amortization and accretion	35,731	24,609	22,923
Impairment of oil and natural gas properties	1,061	—	8,131
Exploration costs	1,747	794	960
Income (loss) before income taxes	20,305	503	(10,514)
Income tax expense	1,690	148	108
Results of operations	$ 18,615	$ 355	$ (10,622)

Reserve Quantity Information

The following information represents estimates of the Company's proved reserves as of December 31, 2017, which have been prepared and presented under SEC rules. These rules require SEC reporting companies to prepare their reserve estimates using specified reserve definitions and pricing based on a 12 -month unweighted average of the first-day-of-the-month pricing. The pricing that was used for estimates of the Company's reserves as of December 31, 2017 was based on an unweighted average 12-month WTI posted price per Bbl for oil and Henry Hub spot natural gas price per Mcf for natural gas for the years ended December 31, 2017, 2016, and 2015 and an unweighted average 12-month Mont Belvieu posted price per Bbl for NGLs for the year ended December 31, 2017 and 27.5% of the unweighted average 12-month WTI posted price for the years ended December 31, 2016 and 2015, as set forth in the following table:

	Year Ended December 31,		
	2017	2016	2015
Oil (per Bbl)	$ 51.34	$ 42.75	$ 50.28
Natural gas (per Mcf)	$ 2.98	$ 2.49	$ 2.58
Natural gas liquids (per Bbl)	$ 31.82	$ 11.73	$ 13.83

Subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This requirement has limited and may continue to limit, the Company's potential to record additional proved undeveloped reserves as it pursues its drilling program. Moreover, the Company may be required to write down its proved undeveloped reserves if it does not drill on those reserves with the required five-year timeframe. The Company does not have any proved undeveloped reserves which have remained undeveloped for five years or more.

Oil and natural gas reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates.

Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and natural gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

The following tables provide a roll forward of the total proved reserves for the years ended December 31, 2017, 2016, and 2015, as well as proved developed and proved undeveloped reserves at the beginning and end of each respective year:

	Crude Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	MBoe
Total proved reserves:				
Balance - January 1, 2015	6,289	27,622	4,299	15,192
Extensions and discoveries	3,377	4,334	588	4,687
Revisions of previous estimates	(3,542)	(15,983)	(2,581)	(8,786)
Purchases of reserves in place	—	—	—	—
Divestitures of reserves in place	—	—	—	—
Production	(472)	(2,074)	(312)	(1,130)
Balance - December 31, 2015	5,652	13,899	1,994	9,963
Extensions and discoveries	3,537	5,694	993	5,479
Revisions of previous estimates	(1,221)	143	356	(841)
Purchases of reserves in place	—	—	—	—
Divestitures of reserves in place	—	—	—	—
Production	(612)	(2,381)	(358)	(1,367)
Balance - December 31, 2016	7,356	17,355	2,985	13,234
Extensions and discoveries	10,011	15,652	2,537	15,157
Revisions of previous estimates	1,970	10,915	1,347	5,136
Purchases of reserves in place	386	1,112	163	734
Divestitures of reserves in place	(16)	(3,009)	(482)	(1,000)
Production	(1,271)	(2,709)	(408)	(2,131)
Balance - December 31, 2017	18,436	39,316	6,142	31,131
Proved developed reserves				
December 31, 2014	3,200	18,753	2,798	9,124
December 31, 2015	2,698	10,116	1,481	5,865
December 31, 2016	3,068	10,574	1,802	6,632
December 31, 2017	8,814	14,171	2,285	13,461
Proved undeveloped reserves				
December 31, 2014	3,089	8,869	1,501	6,068
December 31, 2015	2,954	3,783	513	4,098
December 31, 2016	4,288	6,781	1,183	6,601
December 31, 2017	9,622	25,145	3,857	17,670

Notable changes in proved reserves for the year ended December 31, 2017 included the following:

- *Extensions and discoveries.* During the period, 15,157 MBoe of proved reserves were added as a result of drilling activity primarily in the Wolfcamp and Avalon formations in Loving County within the Northern Delaware Basin.
- *Revisions of previous estimates.* During the period, 5,137 MBoe of proved reserves were added primarily due to an increase in oil, natural gas, and NGL prices and performance improvement.

- *Purchases of reserves in place.* During the period, 734 MBoe of purchased proved reserves relates to the purchase of additional working interest in various operated wells and leasehold interest in Loving County, Texas. See Note 3 - *Acquisitions and Divestitures* for more discussion.
- *Divestitures of reserves in place.* During the period, 1,000 MBoe of divested proved reserves relates to the sale of the Barnett Shale assets. See Note 3 - *Acquisitions and Divestitures* for more discussion.

Notable changes in proved reserves for the year ended December 31, 2016 included the following:

- *Extensions and discoveries.* During the period, 5,479 MBoe of proved reserves were added as a result of drilling activity primarily in the Wolfcamp and Avalon formations in Loving County within the Northern Delaware Basin.
- *Revisions of previous estimates.* During the period, there was a decrease of 841 MBoe in proved reserves primarily due to lower oil, natural gas, and NGL price partially offset by lower production costs and performance improvement.

Notable changes in proved reserves for the year ended December 31, 2015 included the following:

- *Extensions and discoveries.* During the period, 4,687 MBoe of proved reserves were added as a result of drilling activity primarily in the Wolfcamp and Avalon formations in Loving County within the Northern Delaware Basin.
- *Revisions of previous estimates.* During the period, there was a decrease of 8,786 MBoe in proved reserves primarily due to a significant decrease in oil, natural gas, and NGL prices in 2015.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows does not purport to be, nor should it be interpreted to present, the fair value of the oil and natural gas reserves of the property. An estimate of fair value would take into account, among other things, the recovery of reserves not presently classified as proved, the value of unproved properties and consideration of expected future economic and operating conditions.

The estimates of future cash flows and future production and development costs as of December 31, 2017, 2016 and 2015 are based on the unweighted arithmetic average first-day-of-the-month price for the preceding 12-month period. Estimated future production of proved reserves and estimated future production and development costs of proved reserves are based on current costs and economic conditions. All wellhead prices are held flat over the forecast period for all reserve categories. The estimated future net cash flows are then discounted at a rate of 10%.

The standardized measure of discounted future net cash flows relating to proved oil, natural gas and NGLs reserves as of December 31, 2017, 2016, and 2015 is as follows:

	December 31,		
	2017	2016	2015
		(In thousands)	
Future cash inflows	$ 1,125,928	$ 360,651	$ 306,242
Future production costs	(404,934)	(128,689)	(108,968)
Future development and net abandonment costs	(193,073)	(80,522)	(48,647)
Future net inflows before income tax expenses	527,921	151,440	148,627
Future income tax expenses (1)	(25,362)	(1,885)	(1,598)
Future net cash flows	502,559	149,555	147,029
10% discount to reflect timing of cash flows	(152,494)	(69,492)	(60,760)
Standardized measure of discounted future net cash flows	$ 350,065	$ 80,063	$ 86,269

(1) Future income tax expense at December 31, 2017 is attributable to Texas margin tax, the Company's ownership interest in Rosehill Operating and the 21% U.S. federal corporate income tax rate. Amounts at December 31, 2016 and 2015 are attributable to Texas margin tax.

In the foregoing determination of future cash inflows, sales prices used for oil for December 31, 2017, 2016, and 2015 were estimated using the average first-day-of-the-month WTI prices for the twelve months included in each year. Sales prices used for natural gas for December 31, 2017, 2016, and 2015 were estimated using the average first-day-of-the-month Henry Hub prices for the twelve months included in each year. The sales prices used for NGLs for December 31, 2017 was estimated using average first-day-of-the-month Mont Belvieu prices for the twelve months included in the year and for December 31, 2016 and 2015, 27.5% of the average first-day-of-the-month WTI prices for the twelve months included in each year. Prices were adjusted by lease for quality, transportation fees and regional price differentials. Future costs of developing and producing the proved gas and oil reserves reported at the end of each year shown were based on costs determined at each such year-end, assuming the continuation of existing economic conditions.

It is not intended that the FASB's standardized measure of discounted future net cash flows represent the fair market value of its' predecessor's proved reserves. The Company cautions that the disclosures shown are based on estimates of proved reserve quantities and future production schedules which are inherently imprecise and subject to revision and the 10% discount rate is arbitrary. In addition, costs and prices as of the measurement date are used in the determinations and no value may be assigned to probable or possible reserves.

Changes in the standardized measure of discounted future net cash flows relating to proved oil, natural gas and NGLs reserves are as follows:

	December 31,		
	2017	2016	2015
		(In thousands)	
Standardized measure at the beginning of the period	$ 80,063	$ 86,269	$ 205,475
Sales and transfers of oil and natural gas produced	(58,845)	(25,210)	(21,731)
Net change in prices and production costs	54,374	(21,705)	(77,685)
Net change due to purchases and sales of reserves in place	858	—	—
Net change due to extensions, discoveries, and improved recovery	222,590	33,586	42,791
Changes in estimated future development cost	(1,334)	16	420
Net change due to revisions in quantity estimates	13,080	(7,857)	(78,219)
Previously estimated development costs incurred during the year	26,710	3,953	2,907
Accretion of discount	8,122	8,720	20,729
Net change in income taxes	(16,649)	(225)	876
Changes in production rates, timing and other	21,096	2,516	(9,294)
Aggregate change	270,002	(6,206)	(119,206)
Standardized measure at the end of period	$ 350,065	$ 80,063	$ 86,269

Supplemental Quarterly Financial Data (Unaudited)

The following presents selected unaudited quarterly financial data for 2017 and 2016:

	2017			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(In thousands, except per share data)			
Revenues	$ 17,501	$ 14,665	$ 15,295	$ 28,775
Operating expenses	14,247	16,917	18,521	17,657
Operating income (loss)	3,254	(2,252)	(3,226)	11,118
Net income (loss)	4,414	(1,414)	(4,202)	(10,746)
Net income (loss) attributable to noncontrolling interest	—	(2,329)	(5,680)	(10,802)
Series A and Series B Preferred stock dividends	—	8,072	1,942	5,369
Net income (loss) attributable to Rosehill Resources Inc. common stockholders	4,414	(7,157)	(464)	(5,313)
Earnings (loss) per Basic common share	$ 0.75	$ (1.22)	$ (0.08)	$ (0.87)
Earnings (loss) per Diluted common share	$ 0.75	$ (1.22)	$ (0.08)	$ (0.87)

	2016			
	1st Quarter	2nd Quarter	3rd Quarter	4th Quarter
	(In thousands, except per share data)			
Revenues	$ 4,738	$ 8,783	$ 9,682	$ 11,442
Operating expenses	8,256	9,230	9,395	16,567
Operating income (loss)	(3,518)	(447)	287	(5,125)
Net income (loss)	(4,939)	(3,015)	(182)	(7,053)
Net income (loss) attributable to noncontrolling interest	—	—	—	—
Preferred stock dividends	—	—	—	—
Net income (loss) attributable to Rosehill Resources Inc. common stockholders	(4,939)	(3,015)	(182)	(7,053)
Earnings (loss) per Basic common share	$ (0.84)	$ (0.51)	$ (0.03)	$ (1.21)
Earnings (loss) per Diluted common share	$ (0.84)	$ (0.51)	$ (0.03)	$ (1.21)

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) under the Exchange Act, we have evaluated, under the supervision and with the participation of management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2017. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file or submit under the Exchange Act is accumulated and communicated to management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation,we concluded that, as a result of the material weaknesses in our internal control over financial reporting described below, our disclosure controls and procedures were not effective.

Management's Annual Report on Internal Control Over Financial Reporting

Management, including the principal executive officer and principal financial officer, is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rule 13a-15(f) under the Exchange Act. Our internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the consolidated financial statements for external purposes in accordance with GAAP.

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

Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2017, using the criteria in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this evaluation, management believes that our internal control over financial reporting was not effective as of December 31, 2017.

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

A material weakness resulted from an aggregation of significant deficiencies in the following areas:

- asset retirement obligations estimates;
- timely reconciliation and review of accounts;
- determination of accrued liabilities;
- identification and documentation of related party transactions; and
- depreciation, depletion and amortization calculations

A material weakness also existed at December 31, 2017 related to the timely identification and analysis of the appropriate accounting treatment of complex transactions. This relates to the beneficial conversion feature matter requiring restatement, filed on November 3, 2017, of the Company's financial statements for the period ended June 30, 2017, identification of an embedded derivative related to the change of control provision in our Series B Preferred Stock, accounting for noncontrolling interest and income taxes.

These material weaknesses related to the lack of sufficient qualified accounting personnel and inadequately designed accounting processes, which led to the incorrect application of generally accepted accounting principles, ineffective controls over accounting for non-routine and/or complex transactions, and ineffective controls over the financial statement close and reporting processes.

Remediation Activities

Management is committed to the implementation of remediation efforts to address these material weaknesses. We have and continue to recruit finance and accounting personnel, and we continue to evaluate and improve our personnel in all key finance and accounting positions. We are analyzing and improving our accounting processes to provide more timely data, allowing for more robust and timely review and intend to target other improvements in the processes associated with the areas noted above.

We intend to complete the remediation of the material weaknesses discussed above as soon as practicable but we can give no assurance that we will be able to do so. Designing and implementing effective disclosure controls and procedures is a continuous effort that requires us to anticipate and react to changes in our business and the economic and regulatory environments, and to devote significant resources to maintain a financial reporting system that adequately satisfies our reporting obligations. The remedial measures we have taken and intend to take may not fully address the material weaknesses that we have identified, and material weaknesses in our disclosure controls and procedures may be identified in the future. Should we discover such conditions, we intend to remediate them as soon as practicable. We are committed to taking appropriate steps for remediation, as needed.

Attestation Report of the Registered Public Accounting Firm

This annual report does not include an attestation report of our independent registered public accounting firm regarding internal controls over financial reporting. The Company is not required to have, nor did we engage our independent audit firm to perform, an audit of the effectiveness of our internal controls over financial reporting for as long as we are an "emerging growth company" pursuant to the provisions of the JOBS Act.

Changes in Internal Control over Financial Reporting

Other than the ongoing remediation efforts described above, there have been no changes in our internal control over financial reporting during the year ended December 31, 2017 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Management and Board of Directors

Set forth below are the names, ages and positions of each of each of our directors and executive officers:

Name	Age	Position
J.A. (Alan) Townsend	67	President, Chief Executive Officer and Director
Craig Owen	48	Chief Financial Officer
Brian K. Ayers	61	Vice President of Geology
R. Colby Williford	53	Vice President of Land
Gary C. Hanna	60	Chairman
Edward Kovalik	43	Director
Frank Rosenberg	59	Director
William E. Mayer	77	Director
Harry Quarls	65	Director
Francis Contino	72	Director

J.A. (Alan) Townsend has served as our President and Chief Executive Officer since the closing of the Transaction. Mr. Townsend has been the President and a Director of Tema since April 2008. He also currently serves and has served as President and Director of several of Rosemore's subsidiaries, including Gateway since April 2008, President of Crown Central New Holdings, LLC since 2010, President and Director of Tema of PA, LLC since 2012, and President and Director of Raven Gathering System, LLC since 2015. He has been employed by Tema since November 2001. Mr. Townsend has 45 years of engineering, operations, and management experience in the oil and gas industry. He has held several executive positions in public companies, including serving as President of Equitable Resources Energy Co., an exploration and production subsidiary of Equitable Resources, Vice President of KRM Petroleum Inc., an independent exploration and production company, and Chief Executive Officer of Camelot Oil and Gas Company, a privately owned exploration and production company. He earned a Bachelor of Science in Petroleum Engineering in 1972 and a Masters of Engineering in Petroleum Engineering from the Colorado School of Mines in 1977. Mr. Townsend brings significant industry experience leading oil and gas companies to the Company's management team and the Board of Directors.

Craig Owen has served as our Chief Financial Officer since June 26, 2017. Mr. Owen has over 25 years of experience, serving in key executive financial and accounting leadership roles within the energy sector. Mr. Owen most recently served as Senior Vice President and Chief Financial Officer of Southwestern Energy Company from October 2012 to June 2017. Previously, from 2008 to 2012, he was the Controller and Chief Accounting Officer of Southwestern Energy Company. Prior to joining Southwestern Energy Company, Mr. Owen was the Controller, Operations Accounting at Anadarko Petroleum Corporation and held various managerial and financial positions at PricewaterhouseCoopers LLP, ARCO Pipe Line Company and Hilcorp Energy Company. Mr. Owen holds a bachelor's degree in accounting from Texas A&M University and is a Certified Public Accountant.

Brian K. Ayers has served as our Vice President of Geology since April 2017. Mr. Ayers has over 38 years of geology, operations, and management experience in the oil and gas industry. Prior to Rosehill, Mr. Ayers served as Vice President of Geology for Tema from June 2012 to April 2017, and as Vice President of Land from June 2012 to May 2014. Mr. Ayers served Marshfield Oil and Gas as Consultant, Business Development and Geology from January 2012 to May 2012. Mr. Ayers has also held numerous executive positions for public and private companies, including President and Chief Executive Officer of Centurion Exploration Company, Senior Vice President of Geology for America Capital Energy Corporation, Vice President, Division Manager for Samson Lone Star and Vice President, Domestic Exploration for Coastal Oil & Gas Corporation. He began his career in 1980 as an Exploration Geophysicist at Texaco in New Orleans. Mr. Ayers served as an independent director on the Board of Directors of Tamaska Oil and Gas, Ltd. from 2007 to 2014. Mr. Ayers holds a Bachelors of Arts in Geophysical Science from The University of Chicago and a Masters of Business Administration from the Else School of Management, Millsaps College.

R. Colby Williford has served as our Vice President of Land since April 2017. Mr. Williford has over 29 years of petroleum land management experience, including field and in-house positions in Texas, Louisiana, Oklahoma, New Mexico, Colorado, and Wyoming. From May 2014 to April 2017, Mr. Williford served as Vice President to Land for Tema. He held the same position with Momentum Oil & Gas, LLC, from April 2011 to May 2014. Additionally, Mr. Williford has served as Vice President of Land for Centurion Exploration Company and America Capital Energy Corporation, the U.S. oil & gas subsidiary of the ZhongRong Group, Shanghai, China. He began his career in 1985 as a field landman working for small to medium sized companies and transitioned to in-house work providing acquisition & divestiture due diligence, land management and contract negotiation. Mr. Williford holds a Bachelors of Business Administration in International Business from The University of Houston.

Gary C. Hanna, has served as our Chairman since September 2015. Mr. Hanna has over 30 years of executive experience in the energy exploration and production and service sectors, with a primary focus in the mid-continent U.S. and Gulf of Mexico regions. Between September 2015 and April 2017, Mr. Hanna also served as our Chief Executive Officer. Between June 2015 and September 2015, Mr. Hanna evaluated various investment and employment opportunities. Mr. Hanna was a consultant for Energy XXI Gulf Coast, Inc. from June 2014 to June 2015. From 2009 until June 2014, Mr. Hanna served as the Chief Executive Officer of EPL Oil & Gas, Inc., or EPL, a publicly-traded company that was acquired by Energy XXI in June 2014 for $2.3 billion, and was elected as a director of EPL in June 2010 and Chairman in 2013. From 2008 to 2009, Mr. Hanna served as President and Chief Executive Officer of Admiral Energy Services, a start-up company focused on the development of offshore energy services. From 1999 to 2007, Mr. Hanna served in various capacities at Tetra Technologies, Inc., an international oil and gas services production company, including serving as Senior Vice President from 2002 to 2007. Mr. Hanna also served as President and Chief Executive Officer of Tetra's affiliate, Maritech Resources, Inc., and as President of Tetra Applied Technologies, Inc., another Tetra affiliate. From 1996 to 1998, Mr. Hanna served as the President and Chief Executive Officer of Gulfport Energy Corporation, a public oil and gas exploration company. From 1995 to 1998, he also served as the Chief Operations Officer for DLB Oil& Gas, Inc., a mid-continent exploration public company. From 1982 to 1995, Mr. Hanna served as President and Chief Executive Officer of Hanna Oil Properties, Inc., a company engaged in oil services and the development of mid-continent oil and gas prospects. Since November 2015, Mr. Hanna has served as a member of the boards of directors of Hercules Offshore, Inc. and Aspire Holdings Corp. Mr. Hanna holds a B.B.A. in Economics from the University of Oklahoma. Mr. Hanna is well-qualified to serve as director due to his extensive operational, financial and management background.

Edward Kovalik has served as a director since September 2015. Between September 2015 and April 2017, Mr. Kovalik also served as President of the Company. Mr. Kovalik has also been the Chief Executive Officer and Managing Partner of KLR Holdings and KLR Group Holdings, LLC ("KLR Group"), an investment bank specializing in the energy sector which he co-founded in the spring of 2012. Mr. Kovalik manages the firm and focuses on structuring bespoke financing solutions for the firm's clients. Mr. Kovalik has over 17 years of experience as an investment banker. Prior to founding KLR Holdings, from 2002 until April 2012, Mr. Kovalik served in various capacities of Rodman & Renshaw, most recently as Head of Capital Markets and the head of Rodman's Energy Investment Banking team. From 1999 to 2002, Mr. Kovalik was a Vice President at Ladenburg Thalmann & Co., where he focused on private placement transactions for public companies. Mr. Kovalik has served as a member of the boards of directors of River Bend Oil and Gas, LLC since June 2013 and Marathon Patent Group, Inc. a public company, since April 2014. Mr. Kovalik is well-qualified to serve as director due to his extensive financial and management background.

Frank Rosenberg has served as a director since the closing of the Transaction. Since 2006, Mr. Rosenberg has been a Director of Tema Oil & Gas, Gateway Gathering and Marketing and Rosemore. Mr. Rosenberg is also the Co-Chairman of the Board of Directors (since 2013) and Chief Investment Officer of Rosemore, Chairman of the Board of Attransco, which historically operated U.S.-flagged mixed-use oil tankers, and a Director of Glen Eagle Resources (since 2013), a junior miner based in Montreal, Canada. Prior to joining Rosemore, Mr. Rosenberg had a breadth of assignments with Crown Central Petroleum Corporation at the refinery, in the trading operation, the wholesale and retail marketing departments, with the last job being as President & CEO. Mr. Rosenberg began his career with General Electric Credit Corporation (currently, GE Capital) in the marketing and then credit departments. He received an MBA from Emory University and a B.S. in Chemical Engineering from Bucknell University. Mr. Rosenberg was selected to serve on the board of directors due to his extensive experience in the oil and gas industry and significant financial experience.

William E. Mayer has served as a director since the closing of the Transaction. He currently serves and has served as a Director of Rosemore since 2005. Mr. Mayer is the founder of Park Avenue Equity Partners. He was a Professor and Dean at the College of Business, University of Maryland, and at the Simon College of Business, University of Rochester. Mr. Mayer worked for The First Boston Corporation (Credit Suisse), where he was President and CEO. He is on the board of BlackRock Capital Investment Corporation, Premier, Inc. and Lee Enterprises. He was Chairman of the Aspen Institute, and Chairman of the Board of the University of Maryland. He is on the board of The Rubin Museum, Atlantic Council, Pardee RAND Graduate School, Global Health Corps, and Miller Buckfire, and is a member of the Council on Foreign Relations, and Vice Chairman of the Middle East Investment Initiative. Mr. Mayer was a First Lieutenant in the U.S. Air Force. He holds a BS and an MBA from the University of Maryland. Mr. Mayer brings significant experience as a board member to the Company's board of directors.

Harry Quarls has served as a director since the closing of the Transaction. He has been Managing Director at Global Infrastructure Partners since January 2009. He serves as Chairman of the Board of SH 130 Concessions Company LLC and as a Director of Opal Resources LLC. Mr. Quarls previously served as Chairman of the Board of Directors of Penn Virginia Corporation, Woodbine Acquisition Corporation, US Oil Sands Corporation and Trident Resources Corp. and as a Director for Fairway Resources LLC. He also served as a Managing Director and Practice Leader for Global Energy at Booz & Co., a leading international management consulting firm, and as a member of Booz's Board of Directors. Mr. Quarls earned an M.B.A. degree from Stanford University and also holds ScM. and B.S. degrees, both in chemical engineering, from M.I.T. and Tulane University, respectively. Mr. Quarls brings considerable financial and energy investing experience, as well as experience on the boards of numerous public and private energy companies, to the Board of Directors.

Francis Contino has served as a director since the closing of the Transaction. He currently serves as Managing Director of FAC&B LLC, a consulting firm he founded in 2008. Additionally, since 2004 he has served as member of the board and Chairman of the Audit Committee of Mettler Toledo International, Inc., a leading global supplier of precision instruments and services. Mr. Contino previously served as Chief Financial Officer, Executive Vice President, and Director of McCormick & Company from 1998 to 2008. Prior to joining McCormick, Mr. Contino served as the Managing Partner of the Baltimore office of Ernst & Young, where he began his career. Mr. Contino completed the Executive Leadership Education Program at The Kellogg School of Business at Northwestern University. He graduated from the University of Maryland in 1968. Mr. Contino was selected to join the Company's board of directors due to his considerable board experience and financial background.

Board of Directors and Terms of Office of Directors

The Company's amended and restated certificate of incorporation provides for the classification of our board of directors into three separate classes, with each class serving a three-year term. At the Special Meeting, the stockholders elected seven directors to our board of directors, with each Class I director having a term that expires at the Company's annual meeting of stockholders in 2018, each Class II director having a term that expires at the Company's annual meeting of stockholders in 2019 and each Class III director having a term that expires at the Company's annual meeting of stockholders in 2020, or in each case until their respective successors are duly elected and qualified, or until their earlier resignation, removal or death.

Our board of directors consists of two individuals serving as Class I directors, two individuals serving as Class II directors and three individuals serving as Class III directors.

Independence of Directors

Because Tema and KLR Sponsor control a majority of the combined voting power of all classes of our outstanding voting stock, we have been a "controlled company" under NASDAQ corporate governance listing standards. Under the NASDAQ 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 NASDAQ 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; and
- the compensation committee be composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities.

If in the future Tema and KLR Sponsor cease to control a majority of the combined voting power of all classes of our outstanding voting stock, we will no longer be a "controlled company" within the meaning of the rules of NASDAQ. Under NASDAQ rules, a company that ceases to be a controlled company must comply with the independent board committee requirements as they relate to the nominating and corporate governance and compensation committees on the following phase-in schedule: (1) one independent committee member at the time it ceases to be a controlled company, (2) a majority of independent committee members within 90 days of the date it ceases to be a controlled company and (3) all independent committee members within one year of the date it ceases to be a controlled company. Additionally, NASDAQ rules provide a 12-month phase-in period from the date a company ceases to be a controlled company to comply with the majority independent board requirement. During these phase-in periods, our stockholders will not have the same protections afforded to stockholders of companies of which the majority of directors are independent. Additionally, if, within the phase-in periods, we are not able to recruit additional directors who would qualify as independent, or otherwise comply with NASDAQ rules, we may be subject to enforcement actions by NASDAQ. Furthermore, a change in our board of directors and committee membership may result in a change in corporate strategy and operation philosophies, and may result in deviations from our current growth strategy.

The Company's board of directors has determined that Messrs. Contino, Mayer, Quarls and Rosenberg are independent within the meaning of NASDAQ Rule 5605(a)(2).

Committees of the Board of Directors

The standing committees of the Company's board of directors consist of an audit committee (the "Audit Committee"), a compensation committee (the "Compensation Committee") and a corporate governance and nominating committee (the "Corporate Governance and Nominating Committee"). Each of the committees reports to the board of directors.

The composition, duties and responsibilities of these committees are set forth below.

Audit Committee

The principal functions of the Company's Audit Committee are detailed in the Company's Audit Committee charter, which is available on the Company's website, and include:

- the appointment, compensation, retention, replacement, and oversight of the work of the independent auditors and any other independent registered public accounting firm engaged by us;
- pre-approving all audit and non-audit services to be provided by the independent auditors or any other registered public accounting firm engaged by us, and establishing pre-approval policies and procedures;
- reviewing and discussing with the independent auditors all relationships the auditors have with the Company in order to evaluate their continued independence;
- setting clear hiring policies for employees or former employees of the independent auditors;
- setting clear policies for audit partner rotation in compliance with applicable laws and regulations;

- obtaining and reviewing a report, at least annually, from the independent auditors describing (i) the independent auditor's internal quality-control procedures and (ii) any material issues raised by the most recent internal quality-control review, or peer review, of the audit firm, or by any inquiry or investigation by governmental or professional authorities, within, the preceding five years respecting one or more independent audits carried out by the firm and any steps taken to deal with such issues;

- reviewing and approving any related party transaction required to be disclosed pursuant to Item 404 of Regulation S-K promulgated by the SEC prior to us entering into such transaction; and

- reviewing with management, the independent auditors, and our legal advisors, as appropriate, any legal, regulatory or compliance matters, including any correspondence with regulators or government agencies and any employee complaints or published reports that raise material issues regarding our financial statements or accounting policies and any significant changes in accounting standards or rules promulgated by the Financial Accounting Standards Board, the SEC or other regulatory authorities.

Under the NASDAQ listing standards and applicable SEC rules, the Company is required to have at least three members of the Audit Committee, all of whom must be independent. Following the closing of the Transaction, our Audit Committee consists of Messrs. Contino, Mayer and Quarls, with Mr. Contino serving as the Chair. We believe that Messrs. Contino, Mayer and Quarls qualify as independent directors according to the rules and regulations of the SEC with respect to audit committee membership. We also believe that Mr. Contino qualifies as our "audit committee financial expert," as such term is defined in Item 401(h) of Regulation S-K.

Compensation Committee

The principal functions of the Company's Compensation Committee are detailed in the Company's Compensation Committee charter, which is available on the Company's website, and include:

- reviewing and approving on an annual basis the corporate goals and objectives relevant to the Company's Chief Executive Officer's compensation, evaluating its Chief Executive Officer's performance in light of such goals and objectives and determining and approving the remuneration (if any) of its Chief Executive Officer based on such evaluation;

- reviewing and approving on an annual basis the compensation of all of the Company's other officers;

- reviewing on an annual basis the Company's executive compensation policies and plans;

- implementing and administering the Company's incentive compensation equity-based remuneration plans;

- assisting management in complying with the Company's proxy statement and annual report disclosure requirements;

- approving all special perquisites, special cash payments and other special compensation and benefit arrangements for the Company's officers and employees;

- if required, producing a report on executive compensation to be included in the Company's annual proxy statement; and

- reviewing, evaluating and recommending changes, if appropriate, to the remuneration for directors.

Our Compensation Committee consists of Messrs. Mayer, Quarls, Rosenberg and Kovalik, with Mr. Mayer serving as the Chair.

Nominating and Governance Committee

The principal functions of the Company's Nominating and Governance Committee are detailed in the Company's Corporate Governance and Nominating Committee charter, which is available on the Company's website, and include:

- identifying individuals qualified to become members of our board of directors, consistent with criteria approved by our board of directors;

- overseeing the organization of our board of directors to discharge the board's duties and responsibilities properly and efficiently;

- identifying best practices and recommending corporate governance principles; and

- developing and recommending to our board of directors a set of corporate governance guidelines and principles applicable to us.

The Nominating and Governance Committee also develops and recommends to the board of directors corporate governance principles and practices and assists in implementing them, including conducting a regular review of our corporate governance principles and practices. The Nominating and Governance Committee oversees the annual performance evaluation of the board of directors and the committees of the board of directors and makes a report to the board of directors on succession planning.

Our Nominating and Governance Committee consists of Messrs. Rosenberg, Contino and Kovalik, with Mr. Rosenberg serving as the Chair.

Indemnification of Directors and Executive Officers

Our amended and restated charter provides that our executive officers and directors are indemnified by us to the fullest extent authorized by Delaware law, as it now exists or may in the future be amended. In addition, our amended and restated certificate of incorporation provides that our directors will not be personally liable for monetary damages to us for breaches of their fiduciary duty as directors, except to the extent such exemption from liability or limitation thereof is not permitted by the DGCL.

We have entered into agreements with our executive officers and directors to provide contractual indemnification in addition to the indemnification provided for in our amended and restated certificate of incorporation. Our bylaws also permit us to maintain insurance on behalf of any executive officer, director or employee for any liability arising out of his or her actions, regardless of whether Delaware law would permit such indemnification. We have purchased a policy of directors' and officers' liability insurance that insures our executive officers, directors and director nominees against the cost of defense, settlement or payment of a judgment in some circumstances and insures us against our obligations to indemnify our executive officers and directors.

These provisions may discourage stockholders from bringing a lawsuit against our directors for breach of their fiduciary duty. These provisions also may have the effect of reducing the likelihood of derivative litigation against executive officers and directors, even though such an action, if successful, might otherwise benefit us and our stockholders. Furthermore, a stockholder's investment may be adversely affected to the extent we pay the costs of settlement and damage awards against executive officers and directors pursuant to these indemnification provisions.

We believe that these provisions and the insurance and the indemnity agreements are necessary to attract and retain talented and experienced officers and directors.

Financial Code of Ethics

We have adopted a Financial Code of Ethics applicable to our directors, executive officers and employees. We have filed copies of our Financial Code of Ethics as an exhibit to our Current Report on Form 8-K filed on May 3, 2017. You will be able to review these documents by accessing our public filings at the SEC's web site at www.sec.gov. In addition, a copy of the Financial Code of Ethics will be provided without charge upon request from us. We intend to disclose any amendments to or waivers of certain provisions of our Financial Code of Ethics Code of Ethics in a Current Report on Form 8-K. See "Where You Can Find More Information."

ITEM 11. EXECUTIVE AND DIRECTOR COMPENSATION

The tables and narrative disclosure below provide compensation disclosure that satisfies the requirements applicable to emerging growth companies, as defined in the JOBS Act.

In this section, we provide disclosure relating to the compensation of our named executive officers paid by the Company following the business combination on April 27, 2017 and Rosemore, Inc., during the rest of 2017. We are also presenting information on historic executive compensation paid by Rosemore, Inc. in 2016 to the individuals who constitute our named executive officers for 2017. The tables and narrative disclosure below provide compensation information for the following individuals:

- J.A. (Alan) Townsend, our President and Chief Executive Officer;
- Craig Owen, our Chief Financial Officer;
- Brian K. Ayers, our Vice President of Geology;
- R. Colby Williford, Vice President of Land; and
- Gary C. Hanna, the Chairman of our board of directors and former Chief Executive Officer.

We refer to Messrs. Townsend, Owen, Ayers, Williford and Hanna herein collectively as our "Named Executive Officers."

2017 Summary Compensation Table

The following table summarizes the compensation paid to our Named Executive Officers for the fiscal years ended December 31, 2017 and 2016.

Name and Principal Position	Year	Salary ($)	Bonus ($)(1)	Non-Equity Incentive Plan Compensation ($)(2)	Stock Awards ($)(3)	All Other Compensation ($)(4)	Total ($)
J.A. (Alan) Townsend	2017	$ 436,567	$ —	$ —	$ 1,864,158	$ 57,266	2,357,991
(President and Chief Executive Officer)	2016	$ 307,000	$ 107,420	$ 132,928	$ —	$ 55,256	602,604
Gary C. Hanna(5)	2017	$ —	$ —	$ —	$ —	$ 224,828 (5)	224,828
(Chairman of the Board of Directors	2016	$ —	$ —	$ —	$ —	—	—
Craig Owen(6)	2017	$ 249,230	$ —	$ —	$ 1,789,594	$ 8,000	2,046,824
(Chief Financial Officer)							
Brian K. Ayers	2017	$ 305,917	$ —	$ —	$ 706,825	$ 12,938	1,025,680
(Vice President, Geology)	2016	$ 267,750	$ 53,550	$ 92,800	$ —	$ 14,826	428,926
R. Colby Williford	2017	$ 263,333	$ —	$ —	$ 512,644	$ 10,133	786,110
(Vice President, Land)	2016	$ 240,000	$ 48,000	$ 59,788	$ —	$ 9,315	357,103

(1) Bonus amounts for 2017 are not calculable as of the date of this Annual Report on Form 10-K. It is anticipated that 2017 bonus amounts will be determined by April 2018, at which time the Company will disclose the amounts of such bonuses. Amounts in this column reflect the discretionary bonus paid by Rosehill Operating to its Named Executive Officers for services provided in 2016.

(2) Amounts in this column for 2016 reflect awards earned by our Named Executive Officers under Rosemore, Inc.'s long-term incentive compensation program, referred to as the Value Added Rights ("VAR") program. Following the Transaction, our Named Executive Officers no longer participate in the VAR program. The numbers represented in this column reflect an estimate of amounts earned at the December 31, 2016 evaluation date under the VAR program. This estimate is based on the price per VAR used for VAR awards evaluated in 2015.

(3) The amounts reflected in the "Stock Awards" column represent the grant date fair value of restricted stock unit awards granted to our Named Executive Officers in November 2017 pursuant to the LTIP (as defined below), as computed in accordance with Financial Accounting Standards Board ("FASB") Accounting Standard Codification ("ASC") Topic 718.

(4) The amounts in this column for 2017 (other than the amount reported for Mr. Hanna) represent the amount of matching contributions made by the Company to the Rosehill Employee Savings Plan & Trust for each participating Named Executive Officer. For 2016, amounts in this column reflect, for all Named Executive Officers other than Mr. Hanna, matching contributions to Rosemore, Inc.'s Employee Savings Plan and Trust made on behalf of our Named Executive Officers and employer contributions made on behalf of the Named Executive Officers under the Rosemore Employee Retirement Account Plan, Supplemental Savings Plan and Supplemental Executive Retirement Plan. Following the Transaction, our Named Executive Officers no longer participate in any plans sponsored or maintained by Rosemore, Inc. The amounts in this column for 2017 do not include amounts related to vacation payments, if any, payable at the time of the Transaction.

(5) Mr. Hanna served as our Chief Executive Officer prior to the closing of the Transaction on April 27, 2017. Mr. Hanna did not receive any compensation for his service as our Chief Executive Officer in 2016 or 2017. Accordingly, the amount included for Mr. Hanna in the "All Other Compensation" column for 2017 reflects the aggregate compensation Mr. Hanna received for his service as the Chairman of our board of directors in 2017, as more fully discussed in "Director Compensation" below, which amount includes $84,821 in cash retainer fees and $140,007 reflecting the aggregate grant date fair value of the restricted stock award granted to Mr. Hanna under the LTIP in fiscal year 2017, computed in accordance with FASB ASC Topic 718.

(6) Mr. Owen's employment with the Company began on June 26, 2017.

Narrative Disclosure to Summary Compensation Table

Base Salaries and Annual Bonus Awards

Other than Mr. Hanna, each of our Named Executive Officers has entered into an employment agreement with Rosehill Operating. The employment agreements provide for annualized base salaries, which provide a minimum, fixed level of cash compensation for services rendered during the year. The Named Executive Officers' respective employment agreements provide for annualized base salaries of $500,000 for Mr. Townsend, $480,000 for Mr. Owen, $325,000 for Mr. Ayers and $275,000 for

Mr. Williford. In addition, for the 2017 fiscal year, our Named Executive Officers (other than Mr. Hanna) were eligible to earn annual cash incentive bonuses of up to 100% for Messrs. Townsend and Owen, 70% for Mr. Ayers and 60% for Mr. Williford, in each case, of the applicable Named Executive Officer's base salary in effect on December 31, 2017. As discussed above, as of the date of filing of this Annual Report on Form 10-K, annual bonus amounts for 2017 have not yet been determined.

Employment Agreements

In connection with the closing of the Transaction, Rosehill Operating entered into employment agreements with each of Messrs. Townsend, Ayers, and Williford setting forth the terms and conditions of their employment. Rosehill Operating also entered into an employment agreement, effective June 26, 2017, with Mr. Owen in connection with his appointment as the Company's Chief Financial Officer. The employment agreements provide for a two-year initial term beginning on the applicable effective date of each employment agreement, which initial term is automatically extended for successive, additional one-year periods, unless either the applicable executive or we provide 30 days' prior written notice that no such automatic extension will occur. The employment agreements provide for an annualized base salary and a discretionary annual bonus based on performance targets determined annually by the Compensation Committee. The employment agreements also provide that the applicable executives will be eligible to receive annual awards under the LTIP on the terms and conditions determined by the Compensation Committee from time to time. While employed under the employment agreements, the executives are eligible for certain additional benefits, including reimbursement of reasonable business expenses, paid vacation, and participation in our benefit plans, programs or arrangements.

The employment agreements also contain certain restrictive covenants, including provisions that create restrictions, with certain limitations, on the applicable executive competing with the Company and its affiliates, soliciting any customers, or soliciting or hiring Company employees or inducing them to terminate their employment. These restrictions are generally intended to apply during the term of the executives' employment with the Company and for the one-year period following termination of employment. In addition, the employment agreements provide for potential severance benefits in connection with certain terminations of employment, as described in "Potential Payments upon Termination or Change in Control" below.

Rosehill Resources Inc. Long-Term Incentive Plan

On April 27, 2017, the stockholders of the Company approved the Rosehill Resources Inc. Long-Term Incentive Plan (the "LTIP"), which permits the grant of a number of different types of equity, equity-based, and cash awards to employees, directors and consultants. The purpose of the LTIP is to provide a means to attract and retain qualified service providers by affording such individuals a means to acquire and maintain stock ownership or awards, the value of which is tied to the performance of the Company. The LTIP also provides additional incentives and reward opportunities designed to strengthen such individuals' concern for the welfare of the Company and their desire to remain in its employ.

On November 9, 2017, the Company granted restricted stock units under the LTIP to each of the Named Executive Officers other than Mr. Hanna. Except as otherwise provided in the applicable award agreement, the restricted stock units vest in three equal installments on the first three anniversaries of the date of the closing of the Transaction, subject to each Named Executive Officer's continued employment through each such vesting date. The unvested restricted stock units held by our Named Executive Officers accrue dividend equivalent right credits ("DERs") equal to the dividends, if any, paid in respect of shares of our common stock. The DERs will be paid in cash within 60 days following the vesting of the associated restricted stock units, or, if applicable, will be forfeited at the same time the associated restricted stock units are forfeited. In addition, the award agreements provide for accelerated vesting of unvested restricted stock units upon certain terminations of employment following a change in control of the Company, as described in "Potential Payments upon Termination or Change in Control" below.

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 retirement plan pursuant to which employees, including our Named Executive Officers other than Mr. Hanna, are permitted to contribute portions of their base compensation to a tax-qualified retirement account. The Company provides matching contributions equal to 100% of elective deferrals up to 3% of eligible compensation and 50% of elective deferrals from 3% to a maximum of 5% of eligible compensation, subject to the applicable contributions limits. Matching contributions are immediately fully vested.

Outstanding Equity Awards at 2017 Fiscal Year-End

The following table provides information concerning equity awards that have not vested for our Named Executive Officers as of December 31, 2017.

		Stock Awards		
Name	Grant Date	Number of Shares or Un its That Have Not Vested (#)(1)		Market Value of Shares or Units That Have Not Vested ($)(2)
J. Alan Townsend Restricted Stock Units	11/4/17	188,680		$ 1,483,025
Gary C. Hanna(3) Restricted Stock Award	7/19/17	17,611	(3)	$ 138,422
Craig Owen Restricted Stock Units	11/4/17	181,133		$ 1,423,705
Brian K. Ayers Restricted Stock Units	11/4/17	71,541		$ 562,312
R. Colby Williford Restricted Stock Units	11/4/17	51,887		$ 407,832

(1) Other than with respect to Mr. Hanna, the equity-based awards included in this column consist of restricted stock units subject to time-based vesting conditions. The restricted stock units granted to our Named Executive Officers on November 9, 2017, will vest in three equal increments on April 27 of each of 2018, 2019 and 2020, subject to the applicable executive's continued employment through each such vesting date.

(2) The amounts reflected in this column represent the market value of the restricted stock award held by Mr. Hanna and the common stock underlying the restricted stock unit awards held by our Named Executive Officers other than Mr. Hanna, computed based on the closing price of our common stock on December 31, 2017, which was $7.86 per share.

(3) As discussed above, Mr. Hanna served as our Chief Executive Officer prior to the closing of the Transaction on April 27, 2017. The award included in this table for Mr. Hanna reflects the restricted stock award Mr. Hanna received for his service as the Chairman of our board of directors in 2017, as discussed in "Director Compensation" below. The forfeiture restrictions applicable to the restricted stock award granted to Mr. Hanna on July 19, 2017, will lapse on the first anniversary of the grant date, subject to Mr. Hanna's continuous service on our board of directors through such date.

Potential Payments upon Termination or Change in Control

Employment Agreements

As discussed above, other than Mr. Hanna, each of our Named Executive Officers has entered into an employment agreement with Rosehill Operating. The employment agreements provide for potential severance benefits in connection with certain terminations of employment. Generally, the employment agreements provide that, upon a resignation by the applicable executive for "good reason" or upon a termination by us without "cause" (including upon the expiration of the then-existing initial term or renewal term, as applicable, due to non-renewal by us), then, subject to the applicable executive's execution and non-revocation of a release within the time provided to do so, the applicable executive will be eligible to receive a severance payment in an amount equal to 12 months' worth of the applicable executive's base salary for the year in which such termination occurs, payable in a lump sum following such termination.

Restricted Stock Units

Subject to the applicable executive's execution and non-revocation of a release, the restricted stock units held by our Named Executive Officers (other than Mr. Hanna) will become immediately fully vested in the event the applicable executive is terminated by the Company without "cause" or for "good reason" (as such terms are defined in the applicable award agreements) within the 18-month period following a "change in control" (as such term is defined in the LTIP).

Applicable Definitions

For purposes of the employment agreements and the restricted stock unit award agreements, "cause" generally means the applicable executive's: (i) material breach of the employment agreement or award agreement, as applicable, any other written agreement between the applicable executive and the Company, or any policy or code of conduct established by the Company; (ii) commission of an act of gross negligence, willful misconduct, breach of fiduciary duty, fraud, theft or embezzlement; (iii) commission of, conviction or indictment for, or plea of *nolo contendere* to, any felony or crime involving moral turpitude; or (iv) willful failure or refusal (other than due to disability) to perform his obligations pursuant to the employment agreement or award agreement, as applicable, or to follow any lawful directive from the Company, provided, however, that the applicable executive will have 30 days to cure such willful failure or refusal following written notice from the Company.

For purposes of the employment agreements and the restricted stock unit award agreements, "good reason" generally means: (i) a material diminution in the applicable executive's base salary (other than across-the-board reduction affecting similarly situated employees in substantially the same proportion as the applicable executive) or authority, duties and responsibilities with the Company, provided, however, that the removal of the applicable executive as an officer or board member of Company or any of its affiliates will not constitute Good Reason; (ii) a material breach by the Company of any of its covenants or obligations under the employment agreement or award agreement, as applicable; or (iii) the relocation of the applicable executive's principal place of employment by more than 75 miles from the location of the his principal place of employment as of the effective date of the employment agreement or award agreement, as applicable. In order for an assertion of a termination for good reason to be effective, the applicable executive must provide written notice to the board of directors of the existence of one of the foregoing conditions within 30 days of the initial existence of such condition, and such condition must remain uncorrected for 30 days following the board of directors' receipt of such written notice.

For purposes of the restricted stock unit award agreements, "change in control" (as defined in the LTIP) generally means: (i) a change in the ownership of the Company whereby any person or group acquires ownership of more than 50% of the total fair market value or total voting power of the stock of the Company; (ii) a change in the effective control of the Company whereby either (A) any person or group acquires ownership of stock of the Company possessing 30% or more of the total voting power of the stock of the Company; or (B) a majority of the members of the board of directors are replaced during any 12-month period by directors whose appointment or election is not endorsed by at least a majority of the members of the board of directors; (iii) a change in the ownership of a substantial portion of the Company's assets whereby any person or group acquires assets of the Company that have a total gross fair market value equal to 40% of the total gross fair market value of all the assets of the Company.

Director Compensation

Our non-employee directors are entitled to receive compensation for services they provide to us consisting of retainers, fees and equity-based compensation as described below. Directors that also provide services to the Company or its affiliates as employees, including Mr. Townsend, do not receive compensation for their service on our board of directors.

Each non-employee director is generally eligible to receive the following for each complete calendar year:

- an annual base retainer fee of $50,000;

- an additional $50,000 retainer fee for the Chairman of the Board of Directors;
- an additional $20,000 retainer fee for the Chair of the Audit Committee;
- an additional $15,000 retainer fee for the Chair of the Compensation Committee; and
- an additional $10,000 retainer for the Chair of the Corporate Governance and Nominating Committee.

All retainers are paid in cash on a quarterly basis in arrears. In addition, each director is reimbursed for: (1) travel and miscellaneous expenses to attend meetings and activities of the board of directors or its committees and (2) travel and miscellaneous expenses related to his or her participation in general education and orientation programs for directors.

In addition to cash compensation, the Company's non-employee directors are eligible to receive annual equity-based compensation under the LTIP. In 2017, each non-employee director received a restricted stock award with an aggregate grant date value equal to approximately $140,000. Generally, the forfeiture restrictions applicable to the restricted stock awards granted in 2017 will lapse on the one-year anniversary of the date of grant of such awards, subject to the applicable non-employee director's continuous service on our board of directors through such vesting date. Restricted stock awards granted to the Company's non-employee directors are subject to the terms and conditions of the LTIP and the award agreements pursuant to which such awards are granted.

2017 Non-Employee Director Compensation

The following table provides information concerning the compensation of our non-employee directors for the fiscal year ended December 31, 2017.

Name	Fees Earned or Paid in Cash ($)(1)	Stock Awards ($)(2)	Total ($)
Gary C. Hanna(3)	$ 84,821	$ 140,007	$ 224,828
Edward Kovalik	$ 50,893	$ 140,007	$ 190,900
Frank Rosenberg	$ 57,679	$ 140,007	$ 197,686
William E. Mayer	$ 61,071	$ 140,007	$ 201,078
Harry Quarls	$ 50,893	$ 140,007	$ 190,900
Francis Contino	$ 64,464	$ 140,007	$ 204,471

(1) Includes annual cash retainer and supplemental retainers for each non-employee director during fiscal 2017, as described above.

(2) Amounts in this column reflect the aggregate grant date fair value of restricted stock awards granted under the LTIP in fiscal year 2017, computed in accordance with FASB ASC Topic 718. The forfeiture restrictions applicable to the restricted stock awards granted in 2017 will lapse on July 19, 2018, subject to each non-employee director's continuous service on our board of directors through such date.

(3) As discussed above, Mr. Hanna served as our Chief Executive Officer prior to the closing of the Transaction on April 27, 2017. Mr. Hanna did not receive any compensation for his service as our Chief Executive Officer in 2016 or 2017. In accordance with SEC rules, the amounts reported in this table for Mr. Hanna are also included in the "All Other Compensation" column of the 2017 Summary Compensation Table above.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The following table sets forth information known to us regarding ownership of shares of our common stock as of April 6, 2018 by:

- each person who is the beneficial owner of more than 5% of the outstanding shares of our common stock;

- each of our named executive officers and directors; and
- all of our executive officers and directors, as a group.

Beneficial ownership is determined according to the rules of the SEC, which generally provide that a person has beneficial ownership of a security if he, she or it possesses sole or shared voting or investment power over that security, including options and warrants that are currently exercisable or exercisable within 60 days.

The percentages in the table below are based on 6,222,299 shares Class A Common Stock and 29,807,692 shares of Class B Common Stock issued and outstanding as of April 6, 2018. In calculating the percentages for a particular holder, we treated as outstanding the number of shares of Class A Common Stock issuable upon exercise of that particular holder's warrants or conversion of that particular holder's Series A Preferred Stock and did not assume exercise of any other holder's warrants or conversion of any other holder's Series A Preferred Stock.

Unless otherwise indicated, we believe that all persons named in the table below have sole voting and investment power with respect to all shares of voting common stock beneficially owned by them.

	Class A Common Stock		Class B Common Stock	
Name and Address of Beneficial Owners(1)	**Number of Shares**	**%**	**Number of Shares**	**%**
More than 5% Stockholders				
KLR Entities(2)	3,544,733	42.1 %	-	-
Rosemore, Inc.(3)	36,159,518	85.3 %	29,807,692	100 %
K2 Principal Fund, L.P.(4)	2,495,728	30.2 %	-	-
Anchorage(5)	8,441,287	59.2 %	-	-
Geode Diversified Fund(6)	715,020	10.4 %	-	-
Buerger Entities(7)	5,164,801	50.9 %	-	-
AQR Capital Management, LLC (8)	489,600	7.3 %		
Warburg(9)	767,000	11 %		
Directors and Named Executive Officers				
Gary C. Hanna(10)	1,391,138	18.7 %	-	-
Edward Kovalik(11)	3,562,344	42.3 %	-	-
J.A. (Alan) Townsend(12)	206,180	3.3 %	-	-
Craig Owen(13)	190,433	3.1 %	-	-
T.J. Thom(14)	140,000	2.2 %	-	-
Harry Quarls (15)	28,429	*	-	-
Francis Contino	27,611	*	-	-
Frank Rosenberg	17,611	*	-	-
William E. Mayer	17,611	*	-	-
All directors and executive officers as a group (9 individuals)	5,581,357	58.0 %	-	-

* Less than one percent.

(1) Unless otherwise noted, the business address of each of the entities or individuals set forth in the table is c/o Rosehill Resources Inc., 16200 Park Row, Suite 300, Houston, Texas 77084.

(2) KLR Group Investments, LLC ("KLR Investments") is the managing member of KLR Sponsor. Mr. Kovalik is the managing member of KLR Group, which owns 100% of KLR Group Investments, LLC, which is the managing member of KLR Sponsor. Includes: (i) 414,601 shares of Class A common stock held by KLR Investments, (ii) 2,118,547 warrants to purchase Class A common stock held by KLR Investments, (iii) 85,565 shares of Class A common stock issuable upon conversion of Series A Preferred Stock held by KLR Investments and (iv) 926,020 shares of Class A common stock held by KLR Sponsor. KLR Sponsor has entered into the SHRRA with Tema and other holders. Pursuant to the SHRRA, KLR Sponsor and Tema have agreed to, among other things, vote their shares of common stock to elect members of the Board of Directors of the Company as set forth therein. Because of the relationship between KLR Sponsor and Tema as a result of the SHRRA, KLR Sponsor may be deemed, pursuant to Rule 13d-3 under the Act, to beneficially own the shares of common stock held by Tema. KLR Sponsor disclaims beneficial ownership of the shares of common stock held by Tema.

(3) Rosemore's address is 1 North Charles Street, 22nd Floor, Baltimore, MD 21201. Includes: (i) 29,807,692 shares of Class B common stock exchangeable (together with a corresponding number of Rosehill Operating Common Units) for Class A Common Stock on a one-to-one basis held by Tema, (ii) 4,000,000 warrants to purchase Class A Common Stock held by Tema, (iii) 750,000 warrants to purchase Class A Common Stock held by Rosemore, and (iv) 18,421 shares of Series A Preferred Stock held by Rosemore Holdings, Inc., a wholly owned subsidiary of Rosemore that are convertible into 1,601,826 shares of Class A Common Stock. Shares held by Tema and Rosemore Holdings, Inc. may be deemed beneficially owned by Rosemore, their sole parent. Tema's address is 1 North Charles Street, 22nd Floor, Baltimore, MD 21201, and Rosemore Holdings, Inc.'s address is 7 St. Paul Street, Suite 820, Baltimore, MD 21202. Tema has entered into the SHRRA with KLR Sponsor and other holders. Pursuant to the SHRRA, KLR Sponsor and Tema have agreed to, among other things, vote their shares of common stock to elect members of the Board of Directors of the Company as set forth therein. Because of the relationship between KLR Sponsor and Tema as a result of the SHRRA, Tema may be deemed, pursuant to Rule 13d 3 under the Act, to beneficially own the shares of common stock held by KLR Sponsor. Tema disclaims beneficial ownership of the shares of common stock held by KLR Sponsor.

(4) Includes 1,165,848 shares of Class A Common Stock issuable upon the exercise of outstanding warrants and 869,565 shares of Class A Common Stock issuable upon conversion of shares of Series A Preferred Stock. K2 Principal Fund, L.P.'s address is 2 Bloor St West, Suite 801, Toronto, Ontario, M4W 3E2. The reported securities are owned directly by the K2 Principal Fund, L.P. (the "Fund"), and indirectly by: K2 GenPar L.P., the general partner of the Fund (the "GP"), K2 GenPar 2009 Inc., the general partner of the GP ("GenPar 2009"), Shawn Kimel Investments Inc., which owns 100% of the equity interests in GenPar 2009 ("SKI"), and Shawn Kimel, the sole owner of SKI. SKI owns 66.5% of the equity interests of K2 & Associates Investment Management Inc. ("K2 & Associates"). K2 & Associates is the investment manager of the Fund. Shawn Kimel, through his ownership of SKI and his being president of each of SKI, the GP, GenPar2009 and K2 & Associates, controls the voting and dispositive power for all of its shares of our common stock.

(5) Includes a total of 3,245,678 shares of Class A Common Stock issuable upon exercise of outstanding warrants, including 1,570,759 shares issuable to Anchorage Illiquid Opportunities V, L.P. and 1,674,919 shares issuable to AIO V AIV 3 Holdings, L.P., and a total of 4,782,607 shares of Class A Common Stock issuable upon conversion of shares of Series A Preferred Stock, including 2,314,521 shares issuable to Anchorage Illiquid Opportunities V, L.P. and 2,468,086 shares issuable to AIO V AIV 3 Holdings, L.P. Anchorage Capital Group, L.L.C. ("ACG"), an SEC-registered investment advisor, is the investment manager of each of Anchorage Illiquid Opportunities V, L.P. and AIO V AIV 3 Holdings, L.P. ACG's address is 610 Broadway, 6th Floor, New York, NY 10112. Anchorage Advisors Management, L.L.C. ("AAM") is the sole managing member of ACG. Mr. Kevin Ulrich is the Chief Executive Officer of ACG and the senior managing member of AAM. ACG, AAM and Mr. Ulrich have indirect voting or investment power with respect to each of Anchorage Illiquid Opportunities V, L.P. and AIO V AIV 3 Holdings, L.P., but each of those entities or natural persons disclaims beneficial ownership in the registrable securities owned by each of Anchorage Illiquid Opportunities V, L.P. and AIO V AIV 3 Holdings, L.P.

(6) Includes 668,174 shares issuable upon conversion of shares of Series A Preferred Stock and 46,846 shares of Common Stock. Geode is a segregated account of Geode Capital Master Fund Ltd and is in the care of Geode Capital Management LP ("GCM LP"). GCM LP's address is One Post Office Square, 20th Floor, Boston, MA 02109. GCM LP has the sole voting or investment power with respect to Geode.

(7) Includes: (i) 418,393 shares of Class A common stock, 1,281,208 warrants to purchase Class A common stock and 22,000 shares of Class A common stock issuable upon conversion of Series A Preferred Stock held by Reid S. Buerger, (ii) 418,393 shares of Class A common stock, 1,281,208 warrants to purchase Class A common stock and 22,000 shares of Class A common stock issuable upon conversion of Series A Preferred Stock held by Alan H. Buerger 2003 Trust for Reid S. Buerger (the "Trust") and (iii) 418,392 shares of Class A common stock, 1,281,208 warrants to purchase Class A common stock and 22,000 shares of Class A common stock issuable upon conversion of Series A Preferred Stock held by 2012 Buerger Family SD LLC (the "LLC"). The address for Mr. Buerger, the Trust and the LLC is 7111 Valley Green Road, Fort Washington, Pennsylvania 19034.

(8) Based solely on Schedule 13G/A filed with the SEC on February 14, 2018. Includes 489,600 shares of Class A Common Stock issuable upon exercise of warrants owned by the Reporting Person. The address for the Reporting Person is Two Greenwich Plaza, Greenwich, CT 06830. AQR Capital Management, LLC, AQR Capital Management Holdings, LLC and CNH Partners, LLC have shared voting power and shared dispositive power with respect to the reported shares shown above.

(9) Based solely on Schedule 13G/A filed with the SEC on February 14, 2018. Includes 767,000 shares of Class A Common Stock issuable upon exercise of warrants held for the accounts of Serenity Now LLC, Option Opportunities Corp, Warberg WF IV LP, Warberg WF V LP and Warberg CA Fund LP (collectively, the "Warberg Funds") and held personally by Mr. Daniel Warsh. Warberg Asset Management LLC serves as investment manager to each of the Warberg Funds. Mr. Warsh is a managing member and the control person of Warberg. The address of the principal business office of each of the Reporting Persons is 716 Oak Street, Winnetka, IL60093.

(10) Includes 1,150,979 shares of Class A Common Stock issuable upon exercise of warrants owned by the Reporting Person and 46,435 shares of Class A Common Stock issuable upon conversion of shares of Series A Preferred Stock owned by Mr. Hanna.

(11) Mr. Kovalik is the managing member of KLR Group, which owns 100% of KLR Group Investments, LLC, which is the managing member of KLR Sponsor. KLR Group Investments, LLC is the managing member of KLR Sponsor. Mr. Kovalik may therefore be deemed to be a beneficial owner of the securities owned by KLR Group and KLR Sponsor.

(12) Includes 10,000 shares of Class A Common Stock issuable upon exercise of warrants owned by the Reporting Person.

(13) Includes 9,300 shares of Class A Common Stock issuable upon exercise of warrants owned by the Reporting Person.

(14) Tiffany J. Thom resigned from her position as Chief Financial Officer on June 26, 2017.

(15) Includes 1,000 shares of Class A Common Stock issuable upon exercise of warrants owned by the Reporting Person.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Founder Shares

In November 2015, pursuant to that certain Securities Subscription Agreement, dated as of November 20, 2015, KLR Sponsor purchased 4,312,500 shares of common stock (such stock, the "Founder Shares"), for $25,000, or approximately $0.006 per share. The Founder Shares are identical to the common stock included in the units sold in the IPO except that the Founder Shares are subject to certain transfer restrictions, as described in more detail below. In December 2015 and February and March 2016, KLR Sponsor returned to us, at no cost, an aggregate of 1,972,500 Founder Shares, which we cancelled. In January 2016, KLR Sponsor transferred 150,000 shares to Ms. Thom, 50,000 shares to Mr. Dow, and 10,000 shares to Messrs. Abbas, Buckner and York. In March 2016, Mr. Dow and Ms. Thom returned to us, at no cost, 10,000 and 30,000 Founder Shares, respectively, which we cancelled. Also in March 2016, KLR Sponsor forfeited an aggregate of 253,670 Founder Shares at no cost upon receiving the underwriters' notice of only a partial exercise of their over-allotment option in connection with the IPO. All of the Founder Shares forfeited were cancelled by the Company. The 2,046,330 remaining Founder Shares represented 20.0% of the outstanding shares upon the completion of the IPO.

On April 28, 2017, all of the outstanding Founder Shares were automatically converted into 3,475,663 shares of Class A Common Stock in connection with the closing of the Transaction. As used herein, unless the context otherwise requires, "Founder Shares" are deemed to include the shares of Class A Common Stock issued upon conversion thereof.

Subject to certain limited exceptions, 50% of the Founder Shares will not be transferred, assigned or sold until the earlier of (i) one year after the date of the consummation of Transaction or (ii) the date on which the closing price of our Class A Common Stock equals or exceeds $12.00 per share (as adjusted for stock splits, stock dividends, reorganizations and recapitalizations) for any 20 trading days within any 30-trading day period commencing 150 days after the Transaction and pursuant to the transfer restrictions agreed upon by KLR Sponsor at the time of our IPO, the remaining 50% of the Founder Shares will not be transferred, assigned or sold until six months after the date of the consummation of the Transaction, or earlier, in either case, if, subsequent to the Transaction, we consummate a subsequent liquidation, merger, stock exchange or other similar transaction which results in all of our shareholders having the right to exchange their common stock for cash, securities or other property, which we refer to as the "Lock-Up Period."

Private Placement Warrants

Simultaneously with the closing of the IPO, the Company consummated the private placement of 8,310,000 warrants at a price of $0.75 per warrant, of which 7,776,667 private placement warrants were sold to KLR Sponsor, and 533,333 private placement warrants were sold to EarlyBirdCapital, Inc. ("EBC"), the representative of the underwriters in the IPO, and its designees, generating gross proceeds of approximately $6.2 million.

On March 21, 2016, simultaneously with the exercise of the over-allotment, the Company consummated the private placement of an additional 98,838 private placement warrants to KLR Sponsor and EBC and its designees, among which 86,483 private placement warrants were purchased by KLR Sponsor and 12,355 private placement warrants were purchased by EBC and its designees, generating gross proceeds of approximately $74,000. The purchase price of the private placement warrants was added to the proceeds from the IPO to be held in the Trust Account pending completion of the Transaction. Each private placement warrant entitles the holder to purchase one share of our Class A Common Stock at $11.50 per share.

The private placement warrants (including the Class A Common Stock issuable upon exercise of the private placement warrants) are non-redeemable so long as they are held by KLR Sponsor or its permitted transferees. KLR Sponsor agreed to additional transfer restrictions relating to its common stock in connection with its entry into the SHRRA. If the private placement warrants are held by someone other than KLR Sponsor or its permitted transferees, the private placement warrants will be redeemable by the Company and exercisable by such holders on the same basis as the public warrants included in the units being sold in the IPO. Otherwise, the private placement warrants have terms and provisions that are identical to those of the public warrants sold as part of the units issued in the IPO.

Related Party Transactions

KLR Sponsor and its affiliates loaned the Company $275,000 in the aggregate by the issuance of unsecured promissory notes, which we refer to as the "Notes", to cover expenses related to the IPO. These Notes were non-interest bearing and were paid in full on the completion of the IPO. In October 2016, KLR Sponsor provided a commitment to loan to KLRE up to an additional $100,000 for working capital purposes. On March 1, 2017, KLRE borrowed the full amount under this commitment, which was repaid at the closing of the Transaction.

Prior to the completion of the Transaction, KLR Group, an affiliate of KLR Sponsor, provided, at no cost to KLRE, office space and general administrative services.

Pursuant to an employment agreement entered into between us and Ms. Thom, we paid Ms. Thom an annualized salary of $200,000 from the consummation of the IPO through December 31, 2016. In lieu of any salary in 2017, Ms. Thom was eligible to receive a bonus equal to the amount of salary she would have received from January 1, 2017 through the date of our initial business combination, or approximately $65,000. We have historically reimbursed an affiliate of KLR Sponsor for certain expenses incurred in connection with the employment of Mr. Hanna and Ms. Thom, including employment related taxes (to be paid in connection with Ms. Thom's annual salary and bonus) and health benefits.

KLR Sponsor, its executive officers and directors, or any of their respective affiliates have historically been reimbursed for any out-of-pocket expenses incurred in connection with activities on our behalf such as identifying potential target businesses and performing due diligence on suitable business combinations. Our audit committee reviews on a quarterly basis all payments that are made to KLR Sponsor, its executive officers and directors or our or their affiliates and determines which expenses and the amount of expenses that will be reimbursed. There is no cap or ceiling on the reimbursement of out-of-pocket expenses incurred by such persons in connection with activities on our behalf.

From time to time we may retain KLR Group to provide certain financial advisory, underwriting, capital raising, and other services for which KLR Group may receive fees in connection with such services. The amount of fees we pay to KLR Group will be based upon the prevailing market for similar services rendered by comparable investment banks for such transactions at such time, and will be subject to the review of our audit committee pursuant to the audit committee's policies and procedures relating to transactions that may present conflicts of interest.

In October 2016, we entered into an agreement with a placement agent and KLR Group in connection with the PIPE Investment. As compensation for the services, we paid the placement agent and KLR Group a cash fee equal to 5.5% of the aggregate gross proceeds of the PIPE Investment (or $4.125 million). Such fee was split evenly between the placement agent and KLR Group.

In December 2017, KLR Group acted as placement agent in connection with the financing of the White Wolf Acquisition. As compensation for the services, we paid KLR Group a cash fee equal to $7.5 million.

At the time of our IPO, we engaged EBC as an advisor in connection with our Transaction. We agreed to pay EBC a cash fee for such services upon the consummation of our initial Transaction in an amount equal to $2.8 million (exclusive of any applicable finders' fees which might become payable). Of such amount, we were allowed to allocate 1% of the gross proceeds of our IPO to other firms that assisted us with our Transaction, and in connection with the closing of the Transaction, we allocated $0.8 million to KLR Group in consideration of its role in assisting us with our Transaction.

Agreements Relating to the Transaction

Shareholders' and Registration Rights Agreement (SHRRA)

Concurrently with the execution of the Business Combination Agreement, KLRE entered into the SHRRA with KLR Sponsor and Tema (each an "SHRRA Sponsor" and together, the "SHRRA Sponsors") and Anchorage Illiquid Opportunities V, L.P. and AIO AIV 3 Holdings, L.P. (collectively, "Anchorage"), the primary investor in the private placement, which governs the rights and obligations of the SHRRA Sponsors and Anchorage with respect to KLRE following the closing of the Transaction. Pursuant to the terms of the SHRRA, and subject to certain exceptions, the SHRRA Sponsors are bound by restrictions on the transfer of (i) 33% of their Common Stock (as defined in the SHRRA) through the first anniversary of the closing of the Transaction and (ii) 67% of their Common Stock through the second anniversary of the closing of the Transaction, *provided* that sales of Common Stock above certain specified prices are permitted between the first and second anniversaries of the closing of the Transaction.

Pursuant to the SHRRA, the SHRRA Sponsors and Anchorage are entitled to certain registration rights, including the right to initiate two underwritten offerings in any twelve-month period and unlimited piggyback registration rights, subject to customary black-out periods, cutback provisions and other limitations as set forth in the SHRRA. Pursuant to the SHRRA, KLRE filed with the SEC a shelf registration statement relating to the offer and sale of the Registrable Securities (as defined in the SHRRA) owned by the SHRRA Sponsors and Anchorage (and any permitted transferees) and has agreed to keep such shelf registration statement effective on a continuous basis until the date as of which all such Registrable Securities have been sold or another registration statement is filed under the Securities Act. In addition, Anchorage has preemptive rights under the SHRRA to participate in future equity issuances by KLRE, subject to certain exceptions, so as to maintain its then-current percentage ownership of our capital stock.

Subject to specified ownership thresholds, KLR Sponsor is entitled to designate two directors for appointment to the Board, Tema is entitled to designate four directors and Anchorage is entitled to designate one director. Each SHRRA Sponsor and Anchorage is entitled to appoint a representative or observer on each committee of the Board. KLR Sponsor initially designated Gary C. Hanna (who serves as the Chairman of the Board) and Edward Kovalik, Tema initially designated J.A. (Alan) Townsend, Frank Rosenberg, William Mayer and Francis Contino and Anchorage designated Harry Quarls. Pursuant to the terms of the SHRRA, each SHRRA Sponsor must vote for the designees of the other SHRRA Sponsor and is entitled to replace any of its designees that are removed from the Board.

Also, pursuant to the SHRRA, ending on the two-year anniversary of closing of the Transaction, the Board may not approve, or cause Rosehill Operating to approve, certain Major Transactions (as such defined in the SHRRA) without the affirmative vote of at least 70% of the directors then serving on the Board. In addition, Anchorage has preemptive rights under the SHRRA to participate in future equity issuances by KLRE, subject to certain exceptions, so as to maintain its then-current percentage ownership of our capital stock.

Certain rights and obligations of the SHRRA Sponsors and Anchorage under the SHRRA will automatically cease if the SHRRA Sponsors and Anchorage (i) no longer hold any of our equity securities or (ii) no longer have the right to designate an individual for nomination to the Board.

Subscription Agreements

In connection with its entry into the Business Combination Agreement, KLRE entered into Subscription Agreements, each dated as of December 20, 2016, with KLR Sponsor and each of The K2 Principal Fund, L.P., Anchorage Illiquid Opportunities V, L.P., AIO V AIV 3 Holdings, L.P. and Geode Diversified Fund, a segregated account of Geode Capital Master Fund Ltd., pursuant to which, among other things, KLRE issued and sold in a private placement an aggregate of 75,000 shares of Series A Preferred Stock, which are convertible into shares of Class A Common Stock at a conversion price of $11.50 per share (subject to certain adjustments) and 5,000,000 warrants for aggregate gross proceeds of $75 million. Additionally, KLR Sponsor contributed 476,540 shares of Class A Common Stock to the purchasers in the private placement. The proceeds from the private placement were used to fund the cash portion of the consideration required to effect the Transaction and any remaining proceeds were used for general corporate purposes, including to finance development and acquisition activities.

Pursuant to the Subscription Agreements, purchasers of Series A Preferred Stock and warrants in the private placement are entitled to certain registration rights, subject to customary black-out periods, cutback provisions and other limitations as set forth therein.

Side Letter

On December 20, 2016, KLR Sponsor and Rosemore entered into a Side Letter, pursuant to which the parties agreed to backstop redemptions by the Company's public stockholders in excess of 30% of the outstanding shares of Class A Common Stock by purchasing shares of Class A Common Stock or Series A Preferred Stock in an amount up to $20 million. Pursuant to the Side Letter, KLR Sponsor agreed to transfer to Rosemore 750,000 warrants. In addition, under the terms of the Side Letter, certain shares of Class A Common Stock held by KLR Sponsor may be reallocated to Rosemore on the second anniversary of the closing date of the Transaction as a result of (i) certain acquisition activities undertaken by the Company as of certain times of determination and (ii) the volume weighted average trading price of the Class A Common Stock as of certain times of determination.

Amended and Restated Limited Liability Company Agreement of Rosehill Operating

At the closing of the Transaction, KLRE and Tema entered into that certain First Amended and Restated Limited Liability Company Agreement of Rosehill Operating (the "Second Amended LLC Agreement"). Following the closing of the Transaction, we operate our business through Rosehill Operating and its subsidiaries. The operations of Rosehill Operating, and the rights and obligations of the holders of the Rosehill Operating Common Units, are set forth in the Second Amended LLC Agreement.

Appointment as Managing Member. Under the Second Amended LLC Agreement, we are a member and the sole managing member of Rosehill Operating. As the sole managing member, we control all of the day-to-day business affairs and decision-making of Rosehill Operating without the approval of any other member, unless otherwise stated in the Second Amended LLC Agreement. As such, we, through our officers and directors, are responsible for all operational and administrative decisions of Rosehill Operating and the day-to-day management of Rosehill Operating's business.

Compensation. We are not entitled to compensation for our services as managing member. We are entitled to reimbursement by Rosehill Operating for any costs, fees or expenses incurred on behalf of Rosehill Operating (including costs of securities offerings not borne directly by members, board of directors compensation and meeting costs, cost of periodic reports to its stockholders, litigation costs and damages arising from litigation, accounting and legal costs); *provided* that we will not be reimbursed for any of our income tax obligations.

Allocations and Distributions. Rosehill Operating will allocate its net income or net loss for each year to the members of Rosehill Operating pursuant to the terms of the Second Amended LLC Agreement, and the members of Rosehill Operating, including us, will generally incur U.S. federal, state and local income taxes on their share of any taxable income of members of Rosehill Operating. Net income and losses of members of Rosehill Operating generally will be allocated first to us with respect to our Series A and Series B preferred units in Rosehill Operating and then to the holders of Rosehill Operating Common Units on a pro rata basis in accordance with their respective percentage ownership of Rosehill Operating Common Units, subject to requirements under U.S. federal income tax law that certain items of income, gain, loss or deduction be allocated disproportionately in certain circumstances. The Second Amended LLC Agreement requires Rosehill Operating to make a corresponding cash distribution to us at any time a dividend is to be paid by us to the holders of our Series A Preferred Stock and Series B Preferred Stock. The Second Amended LLC Agreement allows for distributions to be made by Rosehill Operating to its members on a pro rata basis in accordance with the number of Rosehill Operating Common Units owned by each member out of funds legally available therefor. We expect Rosehill Operating may make distributions out of distributable cash periodically to the extent permitted by the debt agreements of Rosehill Operating and necessary to enable us to cover our operating expenses and other obligations, as well as to make dividend payments, if any, to the holders of our Class A Common Stock. In addition, the Second Amended LLC Agreement generally requires Rosehill Operating to make (i) pro rata distributions (in accordance with the number of Rosehill Operating Common Units owned by each member) to its members, including us, in an amount at least sufficient to allow us to pay our taxes and satisfy our obligations under the Tax Receivable Agreement and (ii) tax advances, which will be repaid upon a redemption, in an amount sufficient to allow each of the members of Rosehill Operating to pay its respective taxes on such holder's allocable share of Rosehill Operating's taxable income after taking into account certain other distributions or payments received by the unitholder from Rosehill Operating or us.

Rosehill Operating Common Unit Redemption Right. The Second Amended LLC Agreement provides Tema with a redemption right, which entitles Tema to cause Rosehill Operating to redeem, from time to time, all or a portion of its Rosehill Operating Common Units (and a corresponding number of shares of Class B Common Stock) for, at Rosehill Operating's option, newly-issued shares of our Class A Common Stock on a one-for-one basis or a cash payment equal to the average of the volume-weighted closing price of one share of Class A Common Stock for the twenty trading days prior to the date Tema delivers a notice of redemption for each Rosehill Operating Common Unit redeemed (subject to customary adjustments, including for stock splits, stock dividends and reclassifications). In the event of a "Reclassification Event" (as defined in the Second Amended LLC Agreement), the managing member is to ensure that each Rosehill Operating Common Unit (and a corresponding share of Class B Common Stock) is redeemable for the same amount and type of property, securities or cash that a share of Class A Common Stock becomes exchangeable for or converted into as a result of such "Reclassification Event." Upon the exercise of the redemption right, Tema will surrender its Rosehill Operating Common Units (and a corresponding number of shares of Class B Common Stock) to Rosehill Operating and (i) Rosehill Operating shall cancel such Rosehill Operating Common Units and issue to the Company a number of Rosehill Operating Common Units equal to the number of surrendered Rosehill Operating Common Units and (ii) the Company shall cancel the surrendered shares of Class B Common Stock. The Second Amended LLC Agreement requires that we contribute cash or shares of our Class A Common Stock to Rosehill Operating in exchange for the issuance to the Company described in clause (i). Rosehill Operating will then distribute such cash or shares of our Class A Common Stock to Tema to complete the redemption. Upon the exercise of the redemption right, we may, at our option, effect a direct exchange of cash or our Class A Common Stock for such Rosehill Operating Common Units in lieu of such a redemption.

Maintenance of One-to-One Ratios. The Second Amended LLC Agreement includes provisions intended to ensure that we at all times maintain a one-to-one ratio between (a) (i) the number of outstanding shares of Class A Common Stock and (ii) the number of Rosehill Operating Common Units owned by the Company (subject to certain exceptions for certain rights to purchase equity securities of the Company under a "poison pill" or similar shareholder rights plan, if any, certain convertible or exchangeable securities issued under the Company's equity compensation plans and certain equity securities issued pursuant to the Company's equity compensation plans (other than a stock option plan) that are restricted or have not vested thereunder) and (b) (i) the number of other outstanding equity securities of the Company (including the Series A Preferred Stock and the warrants) and (ii) the number of corresponding outstanding equity securities of Rosehill Operating. These provisions are intended to result in Tema having a voting interest in the Company that is identical to Tema's economic interest in Rosehill Operating.

Transfer Restrictions. The Second Amended LLC Agreement generally does not permit transfers of Rosehill Operating Common Units by members, subject to limited exceptions. Any transferee of Rosehill Operating Common Units must, among other things, assume by written agreement all of the obligations of a transferring member with respect to the transferred units.

Dissolution. The Second Amended LLC Agreement provides that Rosehill Operating shall dissolve upon the earlier of the sale of all or substantially all of the assets of Rosehill Operating or upon the determination of the managing member. Upon a dissolution event, the proceeds of a liquidation will be distributed in the following order: (i) first, to pay the expenses of winding up Rosehill Operating; (ii) second, to pay debts and liabilities owed to creditors of Rosehill Operating; (iii) third, to set up cash reserves which the managing member reasonably deems necessary for contingent or unforeseen liabilities or certain future payments and (iv) fourth, (A) to the holders of Series A preferred units pursuant to the terms of such securities and (B) then to the members pro-rata in accordance with their respective relative ownership of Rosehill Operating Common Units.

Indemnification and Fiduciary Duties. The Second Amended LLC Agreement provides for indemnification of the managing member, members and officers of Rosehill Operating and their respective subsidiaries or affiliates and provides that, except as otherwise provided therein, we, as the managing member of Rosehill Operating, have the same fiduciary duties to Rosehill Operating and its members as are owed to a corporation organized under Delaware law and its stockholders by its directors.

Tax Receivable Agreement

Certain transactions with Tema in connection with the Transaction resulted in adjustments to the tax basis of the tangible and intangible assets of Rosehill Operating, which should result in increased deductions allocated to us. In addition, Tema may redeem its Rosehill Operating Common Units for shares of Class A Common Stock or cash, as applicable, pursuant to the redemption right described above. Rosehill Operating intends to make for itself (and for each of its material direct or indirect subsidiaries that is treated as a partnership for U.S. federal income tax purposes and that it controls) an election under Section 754 of the Code that will be effective for the taxable year of the Transaction and each taxable year in which a redemption of Rosehill Operating Common Units occurs. Pursuant to the Section 754 election, our acquisitions (or deemed acquisition for U.S. federal income tax purposes) of Rosehill Operating Common Units as a result of redemptions of Rosehill Operating Common Units are expected to result in adjustments to the tax basis of the tangible and intangible assets of Rosehill Operating. These adjustments will be allocated to us. Such adjustments to the tax basis of the tangible and intangible assets of Rosehill Operating would not have been available to us absent its acquisition or deemed acquisition of Rosehill Operating Common Units as a result of redemptions of Rosehill Operating Common Units. The tax basis adjustments described above are expected to increase (for tax purposes) our depreciation and amortization deductions and may also decrease our gains (or increase our losses) on future dispositions of certain assets to the extent tax basis is allocated to those assets. Such increased deductions and losses and reduced gains may reduce the amount of tax that we would otherwise be required to pay in the future.

On April 27, 2017, in connection with the closing of the Transaction, we entered into a Tax Receivable Agreement with Tema. The Tax Receivable Agreement generally provides for the payment by us to Tema of 90% of the net cash savings, if any, in U.S. federal, state and local income tax and franchise tax that we actually realize (or are deemed to realize in certain circumstances) in periods after the closing of the Transaction as a result of: (i) any tax basis increases in the assets of Rosehill Operating resulting from the distribution to Tema of the cash consideration in connection with the Transaction, the shares of Class B Common Stock and the warrants and the assumption by Rosehill Operating of $55 million in Tema indebtedness (the "Tema Liabilities") in connection with the Transaction, (ii) any tax basis increases in the assets of Rosehill Operating resulting from a redemption of Rosehill Operating Common Units, and (iii) imputed interest deemed to be paid by us as a result of, and additional tax basis arising from, payments it makes under the Tax Receivable Agreement. Under the Tax Receivable Agreement, we retain the benefit of the remaining 10% of these cash savings. Certain of Tema's rights under the Tax Receivable Agreement are transferable in connection with a permitted transfer of Rosehill Operating Common Units or following a redemption of Tema's Rosehill Operating Common Units.

Gathering Agreements

At the closing of the Transaction, Rosehill Operating entered into certain crude oil gathering and gas gathering agreements with Gateway, a wholly owned subsidiary of Rosemore, pursuant to which Gateway will receive, gather, store, treat, and redeliver crude oil and gas production from receipt points within certain production areas located in Loving County, Texas that are exclusively dedicated by Rosehill Operating to Gateway, at certain delivery points for downstream transportation. Each gathering agreement has a term of 10 years that automatically renews on a year-to-year basis until terminated by either party pursuant to the agreements. Rosehill Operating will pay Gateway a fee for such services set forth in the gathering agreements. Gateway provided the same services to Tema in the same dedicated area before the Transaction.

Indemnification Agreements

Effective as of the closing date of the Transaction, we entered into indemnification agreements with certain of our directors and executive officers. Each indemnification agreement provides that, subject to limited exceptions, and among other things, we will indemnify the director or executive officer to the fullest extent permitted by law for claims arising in his or her capacity as our director or officer.

Related Party Policy

Prior to the closing of our IPO, we did not have a formal policy for the review, approval or ratification of related party transactions. Accordingly, certain of the transactions discussed above were not reviewed, approved or ratified in accordance with any such policy.

We have adopted a Financial Code of Ethics requiring us to avoid, wherever possible, all conflicts of interests, except under guidelines or resolutions approved by our board of directors (or the appropriate committee of our board) or as disclosed in our public filings with the SEC. Under our Financial Code of Ethics, conflict of interest situations include any financial transaction, arrangement or relationship (including any indebtedness or guarantee of indebtedness) involving the company. A copy of our code of ethics is available on our website.

In addition, our Audit Committee, pursuant to its charter, is responsible for reviewing and approving related party transactions to the extent that we enter into such transactions. An affirmative vote of a majority of the members of the Audit Committee present at a meeting at which a quorum is present is required in order to approve a related party transaction. A majority of the members of the entire Audit Committee will constitute a quorum. Without a meeting, the unanimous written consent of all of the members of the Audit Committee will be required to approve a related party transaction. A copy of the Audit Committee charter is available on our website. We also require each of our directors and executive officers to complete a directors' and officers' questionnaire that elicits information about related party transactions.

These procedures are intended to determine whether any such related party transaction impairs the independence of a director or presents a conflict of interest on the part of a director, employee or officer.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The following table summarizes the fees of BDO USA, LLP, our independent registered public accounting firm, billed to us for each of the last two fiscal years for audit services and billed to us in each of the last two fiscal years for other services:

Fee Category	Fiscal 2017	Fiscal 2016
Audit Fees	$ 962,885	$ 1,261,318
Audit-Related Fees	—	—
Tax Fees	—	—
All Other Fees	—	—
Total Fees	$ 962,885	$ 1,261,318

Audit Fees

Audit fees consist of fees for the audit of our consolidated financial statements, the review of the unaudited interim financial statements included in our quarterly reports on Form 10-Q and other professional services provided in connection with regulatory filings or engagements.

Audit-Related Fees

Audit-related fees consist of fees for assurance and related services that are reasonably related to the performance of the audit and the review of our financial statements and which are not reported under “Audit Fees.”

Tax Fees

Tax fees comprise fees for a variety of permissible services relating to tax compliance, tax planning and tax advice.

All Other Fees

All other fees include the aggregate fees billed in each of the last two fiscal years for services by the independent auditors that are not reported under "Audit Fees," "Audit-Related Fees," or "Tax Fees."

Audit Committee Pre-Approval Policy and Procedures

Our Audit Committee’s charter provides that the Audit Committee must consider and, in its discretion, pre-approve any audit or non-audit service provided to us by our independent registered public accounting firm. The Audit Committee may delegate authority to one or more subcommittees of the Audit Committee consistent with law and applicable rules and regulations of the SEC and NASDAQ.

For the year ended December 31, 2017, all fees of BDO USA, LLP were reviewed and pre-approved by the Audit Committee.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(1) Consolidated Financial Statements

The consolidated financial statements of the Company and reports of independent registered public accounting firms listed in Section 8 of this Annual Report on Form 10-K are filed as a part of this Annual Report on Form 10-K.

(2) Consolidated Financial Statement Schedules

All financial statement schedules are omitted because they are either not required, inapplicable or because the required information is presented in the Company's consolidated financial statements and related notes.

(3) Exhibits

The following is a complete list of exhibits filed as part of this Form 10-K. Exhibit number corresponds to the numbers in the Exhibit table of Item 601 of Regulation S-K.

Exhibit No.	Description
2.1	Business Combination Agreement, dated as of December 20, 2016, by and between KLR Energy Acquisition Corp. and Tema Oil and Gas Company.(2)
2.2	Purchase and Sale Agreement, dated as of October 24, 2017, among Whitehorse Energy, LLC, Whitehorse Energy Delaware, LLC, Whitehorse Delaware Operating, LLC, Siltstone Resources II - Permian, LLC, Siltstone Resources II-B-Permian, LLC, Rosehill Operating Company, LLC, and Rosehill Resources Inc. (8)
2.3	First Amendment to Purchase and Sale Agreement, dated as of October 24, 2017, among Whitehorse Energy, LLC, Whitehorse Energy Delaware, LLC, Whitehorse Delaware Operating, LLC, Siltstone Resources II - Permian, LLC, Siltstone Resources II-B-Permian, LLC, Rosehill Operating Company, LLC, and Rosehill Resources Inc. (8)
2.4	Second Amendment to Purchase and Sale Agreement, dated as of October 24, 2017, among Whitehorse Energy, LLC, Whitehorse Energy Delaware, LLC, Whitehorse Delaware Operating, LLC, Siltstone Resources II - Permian, LLC, Siltstone Resources II-B-Permian, LLC, Rosehill Operating Company, LLC, and Rosehill Resources Inc.
2.5	Third Amendment to Purchase and Sale Agreement, dated as of October 24, 2017, among Whitehorse Energy, LLC, Whitehorse Energy Delaware, LLC, Whitehorse Delaware Operating, LLC, Siltstone Resources II - Permian, LLC, Siltstone Resources II-B-Permian, LLC, Rosehill Operating Company, LLC, and Rosehill Resources Inc.
3.1	Second Amended and Restated Certificate of Incorporation of KLRE. (5)
3.2	Certificate of Amendment of Certificate of Incorporation.**
3.3	Certificate of Designation for the Series A Preferred Stock of KLRE. (5)
3.4	Amended and Restated Bylaws of Rosehill Resources Inc.(5)
3.5	Certificate of Designations for the Series B Preferred Stock of Rosehill Resources Inc. (8)
4.1	Specimen Unit Certificate.(3)
4.2	Specimen Class A Common Stock Certificate.(3)
4.3	Specimen Warrant Certificate.(3)
4.4	Warrant agreement, dated March 10, 2016, between the Company and Continental Stock Transfer & Trust Company. (1)
4.5	Shareholders' and Registration Rights Agreement, dated as of December 20, 2016, by and among Tema Oil and Gas Company, KLR Energy Sponsor, LLC, KLR Energy Acquisition Corp., Anchorage Illiquid Opportunities V, L.P. and AIO V AIV 3 Holdings, L.P.(2)
10.1	Securities Subscription Agreement, dated November 20, 2015, between the Registrant and KLR Energy Sponsor, LLC.(4)
10.2	Letter Agreement by and between the Company, the initial shareholder, officers and directors of the Company. (1)
10.3	Third Amended and Restated Sponsor Warrants Purchase Agreement between the Company and KLR Energy Sponsor, LLC.(1)
10.4	Amended and Restated Warrants Purchase Agreement between the Company and EarlyBird Capital, Inc.(1)
10.5	Form of Indemnification Agreement. (5)
10.6	Form of Employment Agreement. (5)

10.7	Subscription Agreement, dated as of December 20, 2016, by and between KLR Energy Acquisition Corp. and AIO V AIV 3 Holdings, L.P.(2)
10.8	Subscription Agreement, dated as of December 20, 2016, by and between KLR Energy Acquisition Corp. and Anchorage Illiquid Opportunities V, L.P.(2)
10.9	Subscription Agreement, dated as of December 20, 2016, by and between KLR Energy Acquisition Corp. and Geode Diversified Fund, a segregated account of Geode Capital Master Fund Ltd.(2)
10.10	Subscription Agreement, dated as of December 20, 2016, by and between KLR Energy Acquisition Corp. and The K2 Principal Fund, L.P.(2)
10.11	Side Letter, dated as of December 20, 2016, by and between KLR Energy Acquisition Corp., KLR Energy Sponsor, LLC and Rosemore, Inc.(2)
10.12	Waiver Agreement, dated as of December 20, 2016, by and between KLR Energy Acquisition Corp., and KLR Energy Sponsor, LLC.(2)
10.13	Tax Receivable Agreement, dated as of April 27, 2017, by and between the Company and Tema. (5)
10.14	Second Amended and Restated Limited Liability Company Agreement of Rosehill Operating Company, LLC, dated as of December 8, 2017. (8)
10.15	Rosehill Resources Inc. 2017 Long Term Incentive Plan. (5)
10.16	Crude Oil Gathering Agreement, dated April 27, 2017, by and between Rosehill Operating Company, LLC and Gateway Gathering and Marketing Company. (5)
10.17	Gas Gathering Agreement, dated April 27, 2017, by and between Rosehill Operating Company, LLC and Gateway Gathering and Marketing Company. (5)
10.18	Credit Agreement, dated as of April 27, 2017, among Rosehill Operating Company, LLC, PNC Bank, National Association and PNC Capital Markets LLC. (5)
10.19	Commitment Agreement, dated April 25, 2017, by and among the Company, KLR Energy Sponsor, LLC and The K2 Principal Fund, L.P. (6)
10.20	Registration Rights Agreement, dated March 10, 2016, between the Company, KLR Energy Sponsor, LLC, EarlyBirdCapital, Inc. and Chardan Capital Markets, LLC. (1)
10.21	Employment Agreement between J. A. (Alan) Townsend and Rosehill Operating Company, LLC, dated April 27, 2017. (7)
10.22	Employment Agreement between Brian K. Ayers and Rosehill Operating Company, LLC, dated April 27, 2017.
10.23	Employment Agreement between R. Colby Williford and Rosehill Operating Company, LLC, dated April 27, 2017. (7)
10.24	Employment Agreement between Craig Owen and Rosehill Operating company, LLC, dated as of June 5, 2017. (7)
10.25	Series B Redeemable Preferred Stock Purchase Agreement among Rosehill Resources Inc. and the Purchasers party thereto. (8)
10.26	$100,000,000 Note Purchase Agreement by Rosehill Operating Company, LLC, dated as of December 8, 2017.
10.27	First Amendment to Credit Agreement, dated as of April 27, 2017, among Rosehill Operating Company, LLC, PNC Bank, National Association and PNC Capital Markets LLC. (8)
10.28	Form of Restricted Stock Grant Notice and Agreement for Non-Employee Directors. (5)
10.29	Form of Performance Share Unit Grant Notice and Agreement for Executives. *
10.30	Form of Restricted Stock Unit Grant Notice and Agreement for Executives. *
23.1	Consent of Independent Registered Public Accounting Firm, BDO USA, LLP. *
23.2	Consent of Ryder Scott Company, LP. *
31.1	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
31.2	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
32.1	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.***
32.2	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002. ***
99.1	Ryder Scott Company, LP., Summary of Reserves at December 31, 2017. (10)
99.2	Ryder Scott Company, LP., Summary of Reserves at December 31, 2016. (10)
101.INS	XBRL Instance Document.*
101.SCH	XBRL Taxonomy Extension Schema.*
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.*

101.DEF	XBRL Taxonomy Extension Definition Linkbase.*
101.PRE	XBRL Taxonomy Extension Label Linkbase.*
101.LAB	XBRL Taxonomy Extension Presentation Linkbase.*

* Filed herewith.

** To be filed by amendment.

*** Furnished herewith.

(1) Incorporated by reference to the Company's Form 8-K, filed with the Commission on March 16, 2016.

(2) Incorporated by reference to the Company's Form 8-K, filed with the Commission on December 20, 2016.

(3) Incorporated by reference to the Company's Amendment No. 1 to the Registration Statement (File no. 333-209041) on Form S-1/A, filed with the Commission on February 5, 2016.

(4) Incorporated by reference to the Company's Registration Statement (File no. 333-209041) on Form S-1, filed with the Commission on January 19, 2016.

(5) Incorporated by reference to the Company's Form 8-K, filed with the Commission on May 3, 2017.

(6) Incorporated by reference to the Company's Form 8-K, filed with the Commission on April 28, 2017.

(7) Incorporated by reference to the Company's Quarterly Report on Form 10-Q for the quarterly period ended June 30, 2017, filed with the Commission on August 15, 2017.

(8) Incorporated by reference to the Company's Form 8-K, filed with the Commission on December 14, 2017.

(9) Incorporated by reference to the Company's Form 8-K, filed with the Commission on December 22, 2017.

(10) Incorporated by reference to the Company's Registration Statement (File no. 333-223041) on Form S-1, filed with the Commission on February 14, 2018.

ITEM 16. FORM 10-K SUMMARY

None.

SIGNATURES

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

ROSEHILL RESOURCES INC.

April 17, 2018

By: /s/ Craig Owen

Name: Craig Owen

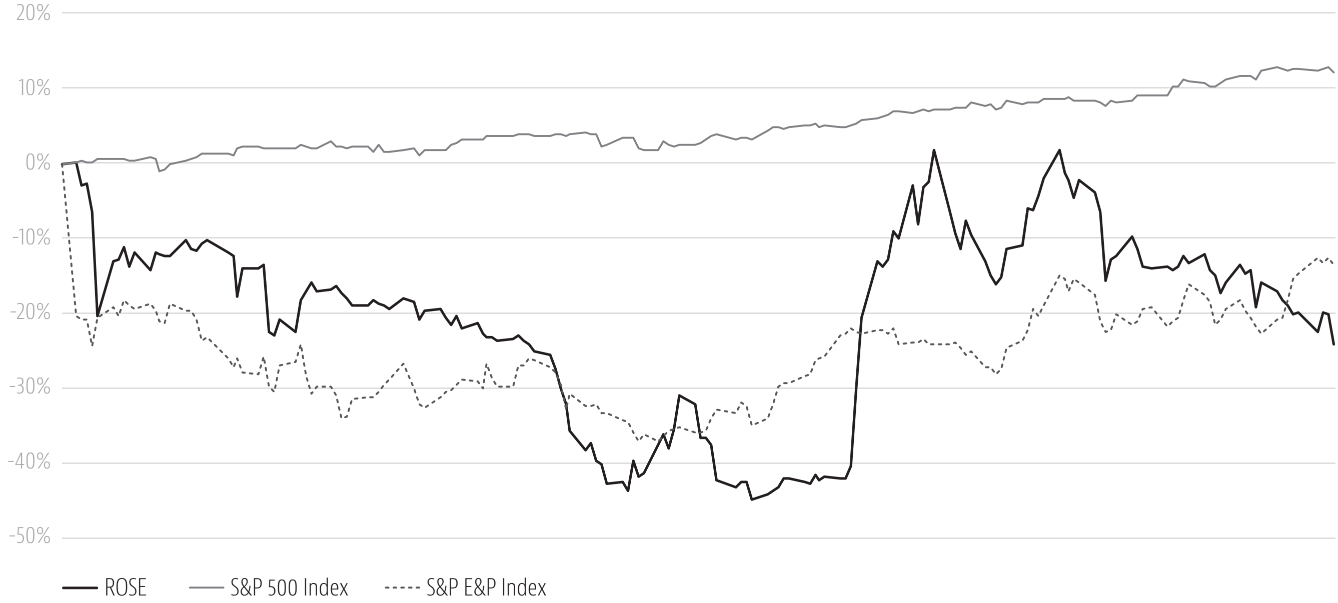
Title: Chief Financial Officer

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

Signature	Title	Date
/s/ J.A. (Alan) Townsend J.A. (Alan) Townsend	Director, President and Chief Executive Officer (Principal Executive Officer)	April 17, 2018
/s/ Craig Owen Craig Owen	Chief Financial Officer (Principal Financial and Accounting Officer)	April 17, 2018
/s/ Gary C. Hanna Gary C. Hanna	Chairman of the Board	April 17, 2018
/s/ Frank Rosenberg Frank Rosenberg	Director	April 17, 2018
/s/ Edward Kovalik Edward Kovalik	Director	April 17, 2018
/s/ Harry Quarls Harry Quarls	Director	April 17, 2018
/s/ William Mayer William Mayer	Director	April 17, 2018
/s/ Francis Contino Francis Contino	Director	April 17, 2018

Relative Stock Price Performance

(4/28/2017 - 12/29/2017)



Non-GAAP Measures

The following table presents a reconciliation of Adjusted EBITDAX to net income (loss), the most directly comparable GAAP financial measure.

	2016	2017	2018 Guidance	
Net income (loss)	$ (15,189)	$ (11,948)	$ 51,000 -	$ 58,000
Interest expense, net	1,822	2,532	13,000 -	17,000
Income tax expense (benefit)	148	1,690	8,000 -	10,000
Depreciation, depletion, amortization and accretion	24,965	36,091	98,000 -	105,000
Impairment of oil and natural gas properties		1,061		
(Gain) loss on unsettled commodity derivatives, net	3,345	16,553		
Transaction costs	2,834	2,618		
Stock based compensation		1,245		
Exploration costs	794	1,747		
(Gain) loss on sale of assets	(50)	(4,995)		
Other (income) expense, net	280	172		
Adjusted EDITDAX	$ 18,949	$ 46,766	$ 170,000 -	$ 190,000

Forward Looking Statements

This annual report includes certain statements that may constitute "forward-looking statements" for purposes of the federal securities laws. All statements, other than statements of historical fact included in this communication, regarding our opportunities in the Delaware Basin, our strategy, future operations, financial position, estimated results of operations, future earnings, future capital spending plans, prospects, plans and objectives of management are forward-looking statements. When used in this communication, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "project," "guidance," "forecast" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

You should not place undue reliance on these forward-looking statements. Although the Company believes that the plans, intentions and expectations reflected in or suggested by the forward-looking statements in this communication are reasonable, no assurance can be given that these plans, intentions or expectations will be achieved or occur, and actual results could differ materially and adversely from those anticipated or implied by the forward-looking statements. Some factors that could cause actual results to differ include, but are not limited to, its ability to acquire additional acreage from the sellers pursuant to the acquisition purchase agreement, the ultimate timing, outcome and results of integrating the acquired assets into its business and its ability to realize the anticipated benefits, commodity price volatility, inflation, lack of availability of drilling and completion equipment and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating oil and natural gas reserves and in projecting future rates of production, cash flow and access to capital, the timing of development expenditures and the other risks and uncertainties discussed under Risk Factors in the Company's Annual Report on Form 10-K, and in other public filings with the SEC by the Company. The Company's SEC filings are available publicly on the SEC's website at www.sec.gov. 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. All forward-looking statements speak only as of the date of this communication. Except as otherwise required by applicable law, the Company disclaims 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 communication.

Corporate Information

Directors

Gary C. Hanna
Chairman

Francis Contino

Edward Kovalik

William Mayer

Harry Quarls

Frank Rosenberg

J.A. (Alan) Townsend

Corporate Officers

J.A. (Alan) Townsend
President and Chief Executive Officer

Craig Owen
Chief Financial Officer

Brian K. Ayers
Vice President of Geology

Paul Larson
Vice President of Engineering

Bryan Freeman
Vice President of Operations

R. Colby Williford
Vice President of Land

Corporate Headquarters
16200 Park Row, Suite 300
Houston, TX 77084
(281) 675-3400

Transfer Agent
Continental Stock Transfer &
Trust Company
(212) 509-4000
cstmail@continentalstock.com

Stock Exchange Listings / Tickers
NASDAQ Capital Market /
ROSE, ROSEW, ROSEU

Independent Registered Public Accounting Firm
BDO USA, LLP

Annual Meeting
The Annual Meeting of Shareholders will be held at 9:00 a.m. Central Time on May 22, 2018, at the Company's Headquarters.

Form 10-K
For an additional copy of the Annual Report on Form 10-K, please contact:

Rosehill Resources Inc.
Attn: Investor Relations
(281) 675-3400
www.rosehillresources.com
info@rosehillres.com

Annual Report Design by Big Pivot Partners / www.bigpivot.net

16200 Park Row
Suite 300
Houston, TX 77084
281-675-3400
info@rosehillres.com