RSP Permian, Inc.
Form 10-K
February 27, 2017
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 10-K

(Mark one)

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

For the fiscal year ended December 31, 2016

or

o 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: 001-36264

RSP Permian, Inc.
(Exact name of registrant as specified in its charter)

Delaware	90-1022997
State or other jurisdiction of incorporation or organization	(I.R.S. Employer Identification Number)
3141 Hood Street, Suite 500 Dallas, Texas	75219
(Address of principal executive offices)	(Zip code)

(214) 252-2700
(Registrant’s telephone number, including area code)

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

Title of each class	Name of each exchange on which registered
Common stock, par value $0.01 per share	New York Stock Exchange

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

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

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 o No ý

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

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definition of “accelerated filer,” “large accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

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

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

The aggregate market value of the common stock held by non-affiliates computed by reference to the price at which the common shares were last sold on the New York Stock Exchange as of June 30, 2016, was approximately $2.8 billion. In making the calculation, the registrant has assumed without adjusting for any other purpose, that all of its employees, directors, and entities controlled by or under common control with them, and no other parties, are affiliates.

The registrant had 142,603,010 shares of common stock outstanding at February 24, 2017.

DOCUMENTS INCORPORATED BY REFERENCE:
(1) Portions of the Definitive Proxy Statement for the Company's Annual Meeting of Shareholders to be held during May 2017 are incorporated into Part III of this report.

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GLOSSARY OF CERTAIN TERMS AND CONVENTIONS USED HEREIN

The following are abbreviations and definitions of certain terms used in this Annual Report on Form 10-K (this "Report"):

“Analogous Reservoir." 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) the same drive mechanism.

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

“Bbl.” A standard barrel containing 42 U.S. gallons.

“Bcf.” One billion cubic feet of natural gas.

“Boe.” One barrel of oil equivalent, calculated by converting natural gas to oil equivalent barrels at a ratio of six Mcf of natural gas to one Bbl of oil.

“Boe/d.” One Boe per day.

“Btu.” One British thermal unit, which is the quantity of heat required to raise the temperature of a one-pound mass of water by one degree Fahrenheit.

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

“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 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.

"Downspacing." Additional wells drilled between known producing wells to better exploit the reservoir.

"Drilled but uncompleted well." A well that has been drilled but has not undergone the final steps of hydraulic fracturing and procedures necessary to place the well on production.

“Dry hole” or “dry well.” A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

“Economically producible.” The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

“Effective Horizontal Acreage.” The summation of our horizontal acreage across the multiple target zones.

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"Exploitation." A development or other project that 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 or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

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

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

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

"MBbl." One thousand barrels.

"MBoe." One thousand Boe.

"Mcf." One thousand cubic feet.

"MMBbls." One million barrels.

"MMBoe." One million Boe.

"MMBtu." One million British thermal units.

"MMcf." One million cubic feet.

"Net acres." The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% interest in 100 acres owns 50 net acres.

"Net production." Production that is owned by us less royalties and production due others.

"Net revenue interest." A working interest owner's gross working interest in production less the royalty, overriding royalty, production payment and net profits interests.

"NGLs." Natural gas liquids. Hydrocarbons found in natural gas that may be extracted as liquefied petroleum gas and natural gasoline.

"NYMEX." The New York Mercantile Exchange.

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

"PDP." Proved developed producing.

“Play.” A geographic area with hydrocarbon potential.

“Plugging.” 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.

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

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

"Proved developed reserves." Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

"Proved reserves." The estimated quantities of oil, NGLs and natural gas that geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

"Proved undeveloped reserves" or "PUDs." Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Undrilled locations can be classified as having PUDs only if a development plan has been adopted indicating that such locations are scheduled to be drilled within five years.

"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 which the well has been previously completed.

"Reliable technology." Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

"Reserves." 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 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).

"Reserve life." A measure of the productive life of an oil and natural gas property or a group of properties, expressed in years. Reserve life is calculated by dividing proved reserve volumes at year end by production volumes. In our calculation of reserve life, production volumes are based on annualized fourth quarter production and are adjusted, if necessary, to reflect property acquisitions and dispositions.

"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 separate from other reservoirs.

"Resources." Resources are quantities of oil and natural gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable and another portion may be considered unrecoverable. Resources include both discovered and undiscovered accumulations.

"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.

"Spot market price." The cash market price without reduction for expected quality, transportation and demand adjustments.

"Standardized measure." Discounted future net cash flows estimated by applying year end prices to the estimated future production of year end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period end costs to determine pre tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre tax cash inflows over our tax basis in the oil and natural gas properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate. The standardized measure does not purport to be

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the fair value of oil and gas reserves or properties; this would require consideration of expected future economic and operating conditions which are not taken into account in calculating the standardized measure.

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

“Unit.” The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

“We,” “our,” “us” or like terms and the “Company” and "RSP" refer to, prior to the IPO Transactions (as defined in “Part I, Item 1. Business-History and Formation”), RSP Permian, L.L.C. and, after the IPO transactions, to RSP Permian, Inc. and its subsidiary, RSP Permian, L.L.C.

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

“Working interest.” The right granted to the lessee of a property to explore for and to produce and own oil, natural gas or other minerals. The working interest owners bear the exploration, development and operating costs on either a cash, penalty or carried basis.

“Workover.” Operations on a producing well to restore or increase production.
“WTI.” West Texas Intermediate, a type of crude oil used as a benchmark in oil pricing and the underlying commodity of NYMEX oil futures contracts.

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CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

Certain statements in this Report, including, without limitation, statements containing the words “believe,” “expect,” “anticipate,” “plan,” “intend,” “foresee,” “will,” “may,” “should,” “would,” “could” or other similar expressions, and statement the Company's business strategy and plans, constitute “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995, 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”). These forward-looking statements are based on our current expectations and beliefs concerning future developments and their potential effect on us. While management believes that these forward-looking statements are reasonable as and when made, there can be no assurance that future developments affecting us will be those that we anticipate. All comments concerning our expectations for future revenues and operating results are based on our forecasts for our existing operations and do not include the potential impact of any future acquisitions. Our forward-looking statements involve significant risks and uncertainties (some of which are beyond our control) and assumptions that could cause actual results to differ materially from our historical experience and our present expectations or projections. Important known factors that could cause actual results to differ materially from those in the forward-looking statements include, but are not limited to, the volatility of commodity prices, product supply and demand, competition, access to and cost of capital, uncertainties about estimates of reserves and resource potential and the ability to add proved reserves in the future, the ability to successfully complete our pending acquisition of Silver Hill E&P II, LLC, and to integrate acquisitions into our operations, the assumptions underlying production forecasts, the quality of technical data, environmental and weather risks, including the possible impacts of climate change, the ability to obtain environmental and other permits and the timing thereof, government regulation or action, the costs and results of drilling and operations, the availability of equipment, services, resources and personnel required to complete the Company’s operating activities, access to and availability of transportation, processing and refining facilities, the financial strength of counterparties to the Company’s credit facility and derivative contracts and the purchasers of the Company’s production and service providers to the Company, and acts of war or terrorism. For additional information regarding known material factors that could cause our actual results to differ from our projected results, please see “Part I, Item 1A. Risk Factors.”

Readers are cautioned not to place undue reliance on forward-looking statements, which speak only as of the date hereof. We undertake no obligation to publicly update or revise any forward-looking statements after the date they are made, whether as a result of new information, future events or otherwise.

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PART I

ITEM 1. BUSINESS

General

RSP Permian, Inc., a Delaware corporation ("RSP Inc." or the "Company"), is an independent oil and natural gas company engaged in the acquisition, exploration, development and production of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin of West Texas. The vast majority of the Company’s acreage is located on large, contiguous acreage blocks in the core of the Midland Basin and the Delaware Basin, both sub-basins of the Permian Basin. The Midland Basin properties are primarily in the adjacent counties of Midland, Martin, Andrews, Ector, Glasscock, and Dawson. The Delaware Basin properties are in Loving and Winkler counties. The Company’s common stock is listed and traded on the NYSE under the ticker symbol “RSPP.”

The Company’s executive offices are located at 3141 Hood St., Suite 500, Dallas, TX 75219, and the Company also maintains an office in Midland, Texas. The Company’s telephone number is 214-252-2700.

History and Formation

RSP Permian, L.L.C., a Delaware limited liability company (“RSP LLC”), was formed in October 2010 by its management team and an affiliate of Natural Gas Partners, a family of energy-focused private equity investment funds. In September 2013, the Company was incorporated in Delaware. In January 2014, pursuant to a corporate reorganization completed in connection with the Company’s initial public offering (“IPO”), RSP LLC became a wholly-owned subsidiary of the Company. Also, in January 2014, in connection with our IPO, the Company acquired (i) working interests in certain acreage and wells in the Permian Basin from Rising Star Energy Development Co., L.L.C. (“Rising Star”), Ted Collins, Jr. (“Collins”), and Wallace Family Partnership, LP (“Wallace LP”) in exchange for shares of the Company’s common stock and cash, (ii) working interests in certain acreage and wells in the Permian Basin from Collins & Wallace Holdings, LLC and Pecos Energy Partners, L.P. (“Pecos”) in exchange for shares of the Company’s common stock, and (iii) net profits interests in oil and natural gas properties in the Permian Basin that were owned and controlled by RSP LLC from ACTOIL, LLC (“ACTOIL”) in exchange for shares of the Company’s common stock (such acquisitions, together with the corporate reorganization, the “IPO Transactions”).

Information presented in this Report on a pro forma basis gives effect to the completion of the IPO Transactions, and information presented in this Report with respect to our predecessor reflects the combined results of RSP LLC and Rising Star. Additional proved reserves and leasehold acreage information in this report is presented on a pro forma basis that gives effect to the completion of the Silver Hill E&P II, LLC ("SHEP II") transaction. Pro forma information reported on a combined basis is not necessarily indicative of the results that would have been obtained if the IPO Transactions had been completed from the Company’s inception.

Business Activities

Shortly after RSP LLC was formed, we began a vertical drilling program on our properties using hydraulic fracture stimulation techniques across multiple productive horizons. These vertical wells were completed in several productive formations and received significant production and reserve contributions from the Wolfcamp and Spraberry formations. These wells are commonly called "Wolfberry" wells in the oil and gas industry. In late 2012, we drilled our first horizontal well and in early 2013 our primary focus shifted to drilling horizontal wells, which we believe provides more attractive returns on a majority of our acreage. We were one of the first operators to implement the use of multi-zone horizontal development in the North Midland Basin. We believe that we were the first operator to drill both a Lower Spraberry horizontal well and a Middle Spraberry horizontal well in the Permian Basin. In addition, RSP was one of the first to drill a Wolfcamp B horizontal well in the North Midland Basin. As a result, RSP has been an early leader in executing a multi-zone horizontal development program in the North Midland Basin and gained substantial industry knowledge relating to several productive zones on its properties. Since initiating our horizontal drilling program in the Midland Basin, we have participated in the completion of 274 horizontal wells with wells completed in five different horizontal zones in the Midland Basin including the Middle Spraberry, Lower Spraberry, Wolfcamp A, Wolfcamp B, and Wolfcamp D. With the acquisition of Silver Hill (defined below), we have acquired properties in which Silver Hill has horizontal wells completed in seven different zones including the Brushy Canyon, 1st Bone Spring, 2nd Bone Spring, 3rd Bone Spring, Wolfcamp X/Y, Lower Wolfcamp A, and Wolfcamp B. We target the multiple oil and natural gas producing stratigraphic horizons, or stacked pay zones, on our properties.

On October 13, 2016, the Company entered into definitive agreements to acquire 100% of Silver Hill Energy Partners, LLC ("SHEP I") and Silver Hill E&P II, LLC ("SHEP II", and together with SHEP I, "Silver Hill") for $1.25 billion of cash and

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31.0 million shares of RSP Inc. common stock in aggregate, implying a total purchase price of $2.4 billion at the time of the acquisition announcement (based on the 20-day volume weighted average price of RSP Inc. common stock). Silver Hill is comprised of two privately held entities that collectively own oil and gas producing properties and undeveloped acreage in Loving and Winkler counties in Texas. Silver Hill owns approximately 40,100 net acres with net production of approximately 15,000 Boe per day as of the acquisition announcement date. Silver Hill's highly contiguous acreage position in the core of the Delaware Basin is complementary to the Company's existing asset base in the Midland Basin and the acquisition creates substantial scale from a production and acreage standpoint. The majority of the purchase price will be recorded to proved and unproved oil and natural gas properties on the Company's balance sheet. The SHEP I acquisition closed on November 28, 2016 with a cash cost of $604 million, before purchase price adjustments, and 15.0 million shares of RSP Inc. common stock. The SHEP II acquisition is expected to close in March 2017. These acquisitions are further described in "Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

During 2016, our developmental capital expenditures, which includes drilling, completion, infrastructure and other and excludes acquisitions, totaled $294 million, which included approximately $275 million spent on drilling and completion activities and $19 million spent on infrastructure and other. In addition, we spent $69 million on bolt-on acquisitions and additions to leasehold in the Midland Basin and approximately $1.2 billion, of which $604 million required the use of cash, on closing the first part of our Silver Hill acquisition, using the stock price of $39.78 at the closing date.

In 2015, our developmental capital expenditures totaled $391 million which included approximately $354 million on drilling and completion activities, $37 million on infrastructure and other, and in addition we spent approximately $456 million on acquisitions and additions to leasehold. As of December 31, 2016, RSP had 11 operated horizontal and 11 non-operated horizontal drilled but uncompleted wells in inventory.

Our board of directors has approved an initial capital budget for drilling, completion, and infrastructure for 2017 of approximately $625 to $700 million, which anticipates increasing our operated horizontal rig count from five currently to eight by the end of the year. We will continue to monitor commodity prices, our cash flow and returns to determine adjustments to our capital budget. We intend to allocate our 2017 capital budget approximately as follows:

- $575 to $625 million for drilling and completion activities; approximately 10% of which is non-operated drilling and completion activities; and
- $50 to $75 million for infrastructure and other.

For the year ended December 31, 2016, our average net daily production was 29,161 Boe/d (approximately 73% oil, 11% natural gas and 16% NGLs), of which 77% was from horizontal well production and 23% was from vertical well production. As of December 31, 2016, we operated and produced from 233 horizontal and 402 vertical wells and were the operator of approximately 81% of our net acreage.

As of December 31, 2016, our estimated pro forma proved oil and natural gas reserves, taking into account both the SHEP I acquisition which closed on November 28, 2016 and the SHEP II acquisition expected to close in March 2017, were 283.3 MMBoe as summarized in the reserve reports by Netherland, Sewell & Associates, Inc. ("Netherland Sewell") our independent reserve engineer. Of these reserves, approximately 39% were classified as PDP. PUDs included in this estimate are from 367 horizontal well locations. As of December 31, 2016, total proved reserves were approximately 70% oil, 12% natural gas and 18% NGLs.

The following table provides summary information regarding our proved reserves as of December 31, 2016..

Estimated Total Proved Reserves

	Oil (MMBbls)	Natural Gas (Bcf)	NGLs (MMBbls)	Total (MMBoe)	% Oil	% Liquids(1)	% Developed
Permian Basin (2)	164.7	176.8	42.7	236.9	70	88	41
SHEP II (3)	34.2	32.6	6.7	46.4	74	88	30
Pro Forma Total (4)	198.9	209.4	49.4	283.3	70	88	39

(1) Includes both oil and NGLs.
(2) Includes properties acquired in the SHEP I acquisition which closed on November 28, 2016.
(3) Includes properties expected to be acquired in the SHEP II acquisition during March 2017.

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(4) Pro Forma Total includes our total estimated proved reserves as of December 31, 2016 including the SHEP II acquisition.

Competition and Markets

General

We are the operator of approximately 81% of our net acreage. As operator, we design and manage the well development and supervise operation and maintenance activities on a day-to-day basis. Independent contractors engaged by us provide all the equipment and personnel associated with these activities. We employ petroleum engineers, geologists and land professionals who work to improve production rates, increase reserves and lower the cost of operating our oil and natural gas properties.

Marketing and Customers

We market the majority of the oil and natural gas production from properties we operate for both our account and the account of the other working interest owners in these properties. We sell our natural gas production to purchasers at market prices. We sell all of our natural gas under contracts with terms greater than twelve months and all of our oil under contracts with terms of twelve months or less, excluding five year oil purchase agreements with Shell Trading (US) Company ("Shell Trading"), Enterprise Crude Oil, LLC, and Plains Marketing, LP. These contracts typically allow for the sale of production quantities at prices that approximate the current market price for the underlying commodity.

We normally sell production to a relatively small number of customers, as is customary in the exploration, development and production business. For the year ended December 31, 2016, two purchasers individually accounted for more than 10% of our revenue: Shell Trading Company (US) (23%) and Enterprise Crude Oil LLC (27%). For the year ended December 31, 2015, four purchasers individually accounted for more than 10% of our revenue: Shell Trading Company (US) (37%), Enterprise Crude Oil LLC (12%), Phillips 66 Company (22%) and Diamondback E&P LLC (13%). For the year ended December 31, 2014, four purchasers individually accounted for more than 10% of our revenue: Shell Trading Company (US) (31%), Enterprise Crude Oil LLC (24%), Diamondback E&P LLC (14%) and Permian Transport & Trading (21%). However, based on the current demand for oil, NGLs, and natural gas, and the availability of other purchasers, we believe that the loss of any one or all of our major purchasers would not have a material adverse effect on our financial condition and results of operations, as crude oil, NGLs, and natural gas are fungible products with well-established markets and numerous purchasers.

Transportation

During the initial development of our fields, we assess the gathering and delivery infrastructure in the areas of our production and then plan accordingly to arrange transportation to gathering systems or pipelines. Our oil is transported from the wellhead to our tank batteries by our gathering systems. The oil is then transported by the purchaser by truck to a tank farm or by pipeline. Our NGLs and natural gas are generally transported from the wellhead to the purchaser's pipeline interconnection point through our gathering system.

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. Larger or more integrated competitors also may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties.

There is also competition between oil and natural gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the governments of the United States and the jurisdictions in which we operate. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our

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future operations. Such laws and regulations may substantially increase the costs of exploring for, developing or producing oil and natural gas and may prevent or delay the commencement or continuation of a given operation.

Seasonality of Business

Weather conditions affect the demand for, and prices of, both oil and natural gas and refinery turnaround and summer driving season affects demand for, and prices of crude oil. The prices of both oil and natural gas are heavily dependent on prevailing and expectations of future supply and demand factors, including current domestic and worldwide storage of each commodity and may not follow a seasonal pattern. Due to seasonal fluctuations or the other above factors impacting pricing, results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis.

Title to Properties

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties in connection with acquisition of leasehold acreage. At such time as we determine to conduct drilling operations on those properties, we conduct a thorough title examination and perform curative work with respect to significant defects prior to commencement of drilling operations. To the extent title opinions or other investigations reflect title defects on those properties, we are typically responsible for curing any title defects at our expense. We generally will not commence drilling operations on a property until we have cured any material title defects on such property. We have obtained title opinions on substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry.

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

We believe that we have satisfactory title to all of our material assets. Although title to these properties is subject to encumbrances in some cases, such as customary interests generally retained in connection with the acquisition of real property, customary royalty interests and contract terms and restrictions, liens under operating agreements, liens related to environmental liabilities associated with historical operations, liens for current taxes and other burdens, easements, restrictions and minor encumbrances customary in the oil and natural gas industry, we believe that none of these liens, restrictions, easements, burdens or 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 right of way grants and permits from public authorities and private parties for us to operate our business.

Oil and Natural Gas Leases

The typical oil and natural gas lease agreement covering our properties provides for the payment of royalties to the mineral owner for all oil and natural gas produced from all wells drilled on the leased premises. The lessor royalties and other leasehold burdens on our properties generally range from 20% to 25%, resulting in a net revenue interest to us generally ranging from 75% to 80% of our working interest.

Regulation of the Oil and Natural Gas Industry

Our operations are substantially affected by federal, state and local laws and regulations. All of the jurisdictions in which we own or operate producing oil and natural gas properties have statutory provisions regulating the exploration for and production of oil and natural gas, including provisions related to permits for the drilling of wells, bonding requirements to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil or natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance

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with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission ("FERC") and the courts. We cannot predict when or whether any such proposals may become effective.

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

Regulation of Production of Oil and Natural Gas

The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. We own interests in properties located in Texas, which regulates drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The laws of Texas also govern a number of conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing or density, and plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing or density. Moreover, Texas imposes a production or severance tax with respect to the production and sale of oil, 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 Transportation of Oil

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 Transportation and Sales of Natural Gas

Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated by agencies of the U.S. federal government, primarily FERC. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Pipeline Act (the "NGPA"), and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed controls affecting wellhead sales of natural gas effective January 1, 1993. The transportation and sale for resale of natural gas in interstate commerce is regulated primarily under the Natural Gas Act of 1938 (the "NGA") and by regulations and orders promulgated under the NGA by FERC. In certain limited circumstances, intrastate transportation and wholesale sales of natural gas may also be affected directly or indirectly by laws enacted by Congress and by FERC regulations.

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

On December 26, 2007, FERC issued Order 704, a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing. Under Order 704, wholesale buyers and sellers of more than 2.2 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. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with FERC’s policy statement on price reporting.

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

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

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

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

Regulation of Environmental and Occupational Safety and Health Matters

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

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

Hazardous Substances and Waste Handling

The Comprehensive Environmental Response, Compensation, and Liability Act ("CERCLA"), also known as the "Superfund" law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the current and past owner or operator of the disposal site or the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, such persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We are able to control directly the operation of only those wells with respect to which we act as operator. Notwithstanding our lack of direct control over wells operated by others, the failure of an operator other than us to comply with applicable environmental regulations may, in certain circumstances, be attributed to us. We also generate materials in the course of our operations that may be regulated as hazardous substances. We are unaware of any liabilities for which we 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 exploration, development or production of crude oil, natural gas or geothermal energy from regulation as hazardous wastes. However, these wastes may be regulated by the U.S. Environmental Protection Agency (the "EPA") or state agencies under RCRA's less stringent nonhazardous solid waste provisions, state laws or other federal laws. Moreover, it is possible that these particular oil and natural gas exploration, development and production wastes now classified as nonhazardous solid wastes could be classified as hazardous wastes in the future. A loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in an increase in our costs to manage and dispose of generated wastes, which could have a material adverse effect on our results of operations and financial position. In addition, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as paint wastes, waste solvents, laboratory wastes and waste compressor oils that may be regulated as hazardous wastes if such wastes have hazardous characteristics. 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 exploration and production activities for many years. Although we believe we have utilized operating and waste disposal practices that were

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standard in the industry at the time, hazardous substances, wastes or petroleum hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off site locations, where such substances have been taken for recycling or disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or petroleum hydrocarbons was not under our control. These properties and the substances disposed or released on, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to undertake response or corrective measures, which could include removal of previously disposed substances and wastes, cleanup of contaminated property or performance of remedial plugging or pit closure operations to prevent future contamination.

Water Discharges

The federal Water Pollution Control Act (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 regulated 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. Obtaining permits has the potential to delay the development of oil and natural gas projects. These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages.

Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as “SPCC plans,” in connection with on site storage of significant quantities of oil. We 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 (“OPA”), which amends and augments the oil spill provisions of the Clean Water Act and imposes certain duties and liabilities on certain “responsible parties” related to the prevention of oil spills and damages resulting from such spills in or threatening waters of the United States or adjoining shorelines. For example, operators of certain oil and natural gas facilities must develop, implement and maintain facility response plans, conduct annual spill training for certain employees and provide varying degrees of financial assurance. Owners or operators of a facility, vessel or pipeline that is a source of an oil discharge or that poses the substantial threat of discharge is one type of “responsible party” who is liable. The OPA applies joint and several liability, without regard to fault, to each liable party for oil removal costs and a variety of public and private damages. Although defenses exist, they are limited. As such, a violation of the OPA has the potential to adversely affect our operations.

Air Emissions

The federal Clean Air Act and comparable state laws restrict the emission of air pollutants from many sources, such as, for example, tank batteries and 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. The need to obtain permits has the potential to delay the development of oil and natural gas projects. 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, the EPA has promulgated final rules under the Clean Air Act that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards (the "NSPS") and the Natural Emission Standards for Hazardous Air Pollutants (the "NESHAPS") programs. With regards to production activities, these final rules have required, among other things, the reduction of volatile organic compound ("VOC") emissions from three subcategories of fractured and refractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non wildcat and non delineation gas wells; and all "other" fractured and refractured gas wells. All three subcategories of wells must route flow back emissions to a gathering line or be captured and combusted using a combustion device such as a flare. However, the "other" wells must 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. The rule is designed to limit emissions of VOC, sulfur dioxide, and hazardous air pollutants from a variety of sources within natural gas processing plants, oil and natural gas production facilities, and natural gas transmission compressor stations. In May 2016, the EPA issued new final rules that, among other things, imposed green completion requirements on all newly-fractured and refractured oil wells. This rule could require a number of modifications to

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our operations, including the installation of new equipment. 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 and production, 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 GHG Emissions

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to the public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, require preconstruction and operating permits for certain large stationary sources. Facilities required to obtain preconstruction permits for their GHG emissions also will be required to meet “best available control technology” standards that will be established by the states or, in some cases, by the EPA on a case by case basis.

These EPA rulemakings 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. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations. More recently, in May 2016, the EPA finalized a suite of regulations that established methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation 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 efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs. These programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. 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 and other climatic events; if any such effects were to occur, they could have a material adverse effect on our exploration and production operations.

Hydraulic Fracturing Activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of oil and/or natural gas from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Hydraulic fracturing is typically regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the Federal Safe Drinking Water Act (the "SDWA") over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities using diesel fuels. Also, in May 2014, the EPA issued an Advanced Notice of Proposed Rulemaking, seeking comment on the development of regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing. In addition, in March 2015, the Bureau of Land Management (the "BLM") of the U.S. Department of the Interior published a revised final rule that imposes requirements for hydraulic fracturing activities on federal lands, including new requirements relating to public disclosure, as well as well bore integrity and handling of flowback water. Furthermore, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. It is unclear how any federal disclosure requirements that add to any applicable state disclosure requirements already in effect may affect our operations.

We may be subject to regulations that restrict our ability to discharge water produced as part of our production operations, and the ability to use injection wells as a disposal option not only will depend on federal or state regulations but also on whether available injection wells have sufficient storage capacities. For example, the EPA has issued a "no discharge" effluent limitation prohibiting oil and natural gas operators from transporting wastewater associated with hydraulic fracturing activities to publicly owned treatment works for disposal.

Certain governmental reviews have been conducted or are underway that focus on the potential environmental impacts of hydraulic fracturing. For example, the EPA has completed a study of the potential environmental effects of hydraulic fracturing on water resources and published a final report in December 2016. Other governmental agencies, including the U.S. Department of Energy, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or

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proposed studies could spur initiatives to further regulate hydraulic fracturing and could ultimately make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

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 Texas Railroad Commission issued a “well integrity rule,” which updates the requirements for drilling, putting pipe down and cementing wells. The rule also includes new testing and reporting requirements, such as (i) the requirement to submit cementing reports after well completion or after cessation of drilling, whichever is later, and (ii) the imposition of additional testing on wells less than 1,000 feet below usable groundwater. In 2013, the Texas Railroad Commission implemented its hydraulic fracturing disclosure rule, which requires oil and gas operators to disclose on the FracFocus website the chemical ingredients and water volumes used in hydraulic fracturing treatments. Local government 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 or prohibit the performance of well drilling in general or hydraulic fracturing in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, 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 exploration, development or production activities, and perhaps even be precluded from drilling wells.

Endangered Species Act and Migratory Birds

The Endangered Species Act (the “ESA”) and (in some cases) comparable state laws were established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species’ habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We may conduct operations on oil and natural gas leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species, such as the sage grouse, that potentially could be listed as threatened or endangered under the ESA may exist. The U.S. Fish and Wildlife Service (the "FWS") 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 material restrictions on 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 FWS 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. In addition, the federal government recently issued indictments under the Migratory Bird Treaty Act to several oil and natural gas companies after dead migratory birds were found near reserve pits associated with drilling activities. The identification or designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse impact on our ability to develop and produce reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

In summary, we believe we are in substantial compliance with currently applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2016, nor do we anticipate that such expenditures will be material in 2017.

OSHA

We are subject to the requirements of the Occupation Health and Safety 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. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Related Permits and Authorizations

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

Related Insurance

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

Employees

As of December 31, 2016, we had 115 full-time employees. We hire independent contractors on an as needed basis. We have no collective bargaining agreements with our employees. We believe our employee relationships are satisfactory.

Available Information

We file or furnish annual, quarterly and current reports, proxy statements and other documents with the United States Securities and Exchange Commission (the “SEC”) under the Exchange Act. The public may read and copy any materials that we file or furnish with the SEC at the SEC's Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. Also, the SEC maintains a website that contains reports, proxy and information statements, and other information regarding issuers, including us, that file or furnish electronically with the SEC. The public can obtain any documents that we file with the SEC at www.sec.gov.

We also make available free of charge through our website, www.rsppermian.com, our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Information contained on or connected to our website is not incorporated by reference into this report and should not be considered part of this report or any other filing that we make with the SEC.

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ITEM 1A. RISK FACTORS

The nature of the business activities conducted by the Company subjects it to certain hazards and risks. The following is a summary of some of the material risks relating to the Company's business activities. Other risks are described in "Part I. Item 1. Business—Competition and Markets" and "—Regulation of the Oil and Gas Industry," and "Part II. Item 7A. Quantitative and Qualitative Disclosures About Market Risk." These risks are not the only risks facing the Company. The Company's business could also be affected by additional risks and uncertainties not currently known to the Company or that it currently deems to be immaterial. If any of these risks actually occurs, it could materially harm the Company's business, financial condition or results of operations and impair the Company's ability to implement business plans or complete development activities as scheduled. In that case, the market price of the Company's common stock could decline.

Oil, NGL and natural gas prices are volatile. A further reduction or sustained decline in commodity prices may adversely affect our operations, financial condition and level of expenditures for the development of our oil, NGL and natural gas reserves.

The prices we receive for our oil, NGLs and natural gas production heavily influence our revenue, operating results, profitability, access to capital, future rate of growth and carrying value of our properties. Oil, NGLs and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the commodities markets have been volatile, and these markets will likely continue to be volatile in the future. The prices we receive for our oil, NGL and natural gas production significantly affect our operations, financial condition, access to capital, future rate of growth, carrying value of our properties and level of expenditures. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control and include the following:

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

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In the second half of 2014, oil prices began a rapid and significant decline as the global oil supply began to outpace demand. During 2015 and 2016, the global oil supply continued to outpace demand, resulting in a sustained decline in realized prices for oil production. Although there has been a dramatic decrease in drilling activity in the industry, oil storage levels in the United States remain at historically high levels. Until supply and demand balance and oil storage levels return to historical norms, prices will likely remain volatile. The U.S. Federal Reserve has indicated that it intends to raise interest rates, as a result the dollar has strengthened relative to other leading currencies, which has caused oil prices to weaken as oil prices are U.S. dollar-denominated and generally move inversely to the value of the U.S. dollar. In addition, the lifting of economic sanctions on Iran has resulted in increasing supplies of oil from Iran, adding further downward pressure to oil prices. Recently, in response to continued depressed oil prices and elevated oil storage levels, OPEC and certain other non-OPEC nations announced coordinated plans to cut their overall production levels aimed to reduce worldwide oil supplies and help strengthen the price of crude oil. Such actions by OPEC and other nations to curtail production may not result in lifting prices as many other demand and supply factors may ultimately weigh on future oil prices. NGL prices generally correlate to the price of oil. Also adversely affecting the price for NGLs is the supply of NGLs in the United States, which has continued to grow due to an increase in industry participants targeting projects that produce NGLs in recent years. Prices for domestic natural gas began to decline during the third quarter of 2014 and remained weak throughout 2015 and 2016. The declines in natural gas prices are primarily due to an imbalance between supply and demand across North America. The continued duration and magnitude of these commodity price declines cannot be accurately predicted.

Lower commodity prices may 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 our reserves as existing reserves are depleted. Lower commodity prices may also reduce the amount of oil, NGLs and natural gas that we can produce economically and a significant portion of our exploitation, development and exploration projects could become uneconomic. This may result in our having to make significant downward adjustments to our estimated proved reserves. As a result, if commodity prices remain depressed for a lengthy period of time or experience a further substantial or extended decline our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures may be materially and adversely affected.

Our derivative activities could result in financial losses or could reduce our earnings. Additionally, our hedging program may not protect us against continuing and prolonged declines in the price of oil and natural gas.

We enter into derivative instrument contracts from time to time for a portion of our production. As of December 31, 2016, we had entered into hedging contracts through December 31, 2017 covering a total of approximately 7,988 MBbls of our projected oil production. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

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

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

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

As of December 31, 2016, the estimated fair value of our commodity derivative contracts was a net liability of approximately $17.0 million. Any default by the counterparties, to these derivative contracts when they become due, may have a material adverse effect on our financial condition and results of operations.

In addition, derivative arrangements could limit the benefit we would receive from increases in the prices for oil and natural gas, which could also have a material adverse effect on our financial condition.

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Although we have hedged a portion of our estimated 2017 production, these hedges may be inadequate to protect us from continuing and prolonged decline in the price of oil and natural gas. To the extent that the price of oil and natural gas remain at current levels or declines further, we will not be able to hedge future production at the same level as our current hedges, and our results of operations and financial condition would be negatively impacted.

Our exploitation, development and exploration 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 reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the exploitation, development and acquisition of oil and natural gas reserves. Our 2017 capital budget for drilling, completion, recompletion and infrastructure is currently estimated to be approximately $625 million to $700 million. Our capital budget excludes acquisitions. We expect to fund 2017 capital expenditures with cash generated by operations, borrowings under our revolving credit facility, our cash balance at year-end, and possibly offerings of our debt and equity securities. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, oil, NGL, and natural gas prices; actual drilling results; the availability of drilling rigs and other services and equipment; and regulatory, technological and competitive developments. A reduction in commodity prices from current levels may result in a decrease in our actual capital expenditures, which would negatively impact our ability to grow production.

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

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

If our revenues or the borrowing base under our revolving credit facility decrease as a result of lower oil and natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If cash flow generated by our operations or available borrowings under our revolving credit facility are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our properties, which in turn could lead to a decline in our reserves and production, and could materially and adversely affect our business, financial condition and results of operations.

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

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

- landing our wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running our casing the entire length of the wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

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

- the ability to fracture stimulate the planned number of stages;

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- 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 we anticipated and we could incur material write downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

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

Our future financial condition and results of operations will depend on the success of our exploitation, development and acquisition 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 purchase, explore, develop or otherwise exploit prospects or properties will depend, in part, on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see “-Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.” In addition, our cost of drilling, completing and operating wells is often uncertain before drilling commences.

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

- delays imposed by or resulting from compliance with regulatory requirements including limitations resulting from wastewater disposal, discharge of 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;
- 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.

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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. Any significant variance could materially affect the estimated quantities and present value of our reserves. For instance, initial production rates reported by us or other operators may not be indicative of future or long term production rates. In addition, stated recovery efficiencies may vary from projected rates and production declines may deviate from current estimates and may be more rapid and irregular when compared to initial production rates. We may also adjust reserve estimates to reflect additional production history, results of exploration and development activities, current commodity prices and other existing factors.
You should not assume that the present value of future net revenues from our reserves is the current market value of our estimated reserves. We generally base the estimated discounted future net cash flows from reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.
Our Effective Horizontal Acreage is based on our and other operators' current drilling results and our interpretation of available geologic and engineering data and therefore is an inexact estimate subject to various uncertainties.
Our Effective Horizontal Acreage is what we believe to be our acreage position that is prospective for hydrocarbon production across our target horizontal zones underneath our total surface acreage of 138,633 gross (83,986 net) acres. Our belief is based upon our evaluation of our initial horizontal drilling results and those of other operators in our area to date, combined with our interpretation of available geologic and engineering data. Although we believe this acreage metric more accurately conveys our horizontal drilling opportunities in our target zones, and we believe our analysis of engineering, geological, geochemical and seismic data is based on industry standards, our calculation of our Effective Horizontal Acreage is an inexact estimate. We cannot assure you that all, or any portion of our Effective Horizontal Acreage, is prospective for our target zones, that any portion of our Effective Horizontal Acreage will ever be drilled or that, if drilled, will result in commercially productive wells.
Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill such locations.
Our management team has specifically identified and scheduled certain drilling locations as an estimation of our future multi year drilling activities on our existing acreage. These drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the numerous drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas 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, 2016, we had identified 5,003 horizontal drilling locations on our acreage. 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 exploitation, development and exploration 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 reserves." Any drilling activities we are able to conduct on these locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a

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downward revision of our estimated proved reserves, which could have a material adverse effect on our future business and results of operations.

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

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

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

Water and sand are essential components of deep shale oil and natural gas production processes. Our ability to obtain water and sand for our operations may be affected by the price of water and sand, the availability of transportation and other market conditions. Additionally, some governmental authorities have restricted the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supplies. If we are unable to obtain water or sand to use in our operations, we may be unable to economically produce oil and natural gas, which could have a material and adverse effect on our financial condition, results of operations and cash flows.

Our producing properties are located in the Permian Basin of West Texas, making us vulnerable to risks associated with operating in one major geographic area.

All of our producing properties are geographically concentrated in the Permian Basin of West Texas. At December 31, 2016, all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, availability of equipment and personnel, water shortages or other drought related conditions or interruption of the processing or transportation of oil, NGLs or natural gas. For example, all of our oil contracts are impacted by the Midland-Cushing price differential, which reflects the difference between the price of crude at Midland, Texas, versus the price of crude at Cushing, Oklahoma, a major hub where production from Midland is often transported via pipeline. The price we currently realize on barrels of oil we sell is reduced by the value of the Midland-Cushing differential, which reached as high as $21 per barrel in August 2014. If the Midland-Cushing differential, or other price differentials pursuant to which our production is subject, were to widen due to oversupply or other factors, our revenue could be negatively impacted.

The marketability of our production is dependent upon transportation and other facilities, certain of which we do 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 transported from the wellhead to our tank batteries by owned and third party gathering systems. Our purchasers then transport the oil by truck or pipeline for transportation. Our natural gas production is generally transported by gathering lines from the wellhead to a gas processing facility. We do not control these trucks and other third party transportation facilities and our access to them 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 our or third party transportation facilities or other production facilities could adversely impact our ability to deliver to market or produce our oil and natural gas and thereby cause a significant interruption in our operations. If, in the future, we are unable, for any sustained period, to implement acceptable delivery or transportation arrangements or encounter production related difficulties, we may be required to shut in or curtail production. Any such shut in or curtailment, or an inability to obtain favorable terms for delivery of the oil and natural gas produced from our fields, would materially and adversely affect our financial condition and results of operations.

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

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

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

As of December 31, 2016, 59% of our total estimated proved reserves were classified as proved undeveloped. Development of these undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves, increases in costs to drill and develop such reserves or decreases in commodity prices will reduce the value of our estimated PUDs and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our PUDs as unproved reserves. Further, we may be required to write down our PUDs if we do not drill those wells within five years after their respective dates of booking.

If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value for a significant period of time, we will be required to take write downs of the carrying values of our properties.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our properties. A write-down constitutes a non cash charge to earnings. We may incur impairment charges in the future, 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 develop those reserves, our reserves and production will decline, which would adversely affect our future cash flows and results of operations.

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

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

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

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

Domestic and global economic conditions, especially in the energy industry, are volatile and there is the possibility that lenders could react by tightening credit. These conditions and factors may adversely affect the ability of our customers and other contractual counterparties to pay amounts owed to us from time to time and to otherwise satisfy their contractual obligations to us, as well as their ability to access the credit and capital markets for such purposes. Moreover, our contractual counterparties may be unable to satisfy their contractual obligations to us due to the volatile market or other reasons. If a counterparty is unable to satisfy its contractual obligation to purchase oil, NGLs or gas from us, we may be unable to sell such production to another customer on terms we consider acceptable. Furthermore, the inability of our contractual counterparties to pay amounts owed to us and to otherwise satisfy their contractual obligations to us and third parties may materially and adversely affect our business, financial condition, results of operations, and cash flows.

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, worker health and safety aspects of our operations, or otherwise relating to environmental

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

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

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

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations.

Our exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and natural gas, including the possibility of:

- environmental hazards, such as uncontrollable releases of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater, air and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- personal injuries and death;
- natural disasters; and
- terrorist attacks targeting oil and natural gas related facilities and infrastructure.

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

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;

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- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance for any or all of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

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

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

- unexpected drilling conditions;
- title problems;
- pressure or lost circulation in formations;
- equipment failure or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental or contractual requirements; and
- 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 businesses or assets, and any inability to do so may disrupt our business and hinder our ability to grow.

From time to time, 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 be unable to complete the acquisitions, or do so on commercially acceptable terms. Competition for acquisitions may also increase the cost of, or cause us to refrain from, successfully completing acquisitions.

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

In addition, our revolving credit facility, the indenture governing our 6.625% senior notes due 2022 and the indenture governing our 5.25% senior notes due 2025 (collectively, the "senior notes") impose certain limitations on our ability to enter into mergers or combination transactions. Our revolving credit facility and the indentures also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses. If we desire to engage in an

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acquisition that is otherwise prohibited by our revolving credit facility or the indentures governing our senior notes, we will be required to seek the consent of our lenders or the holders of the senior notes in accordance with the requirements of the credit facility or the indentures, which consent may be withheld by the lenders under our credit facility or such holders of senior notes at their sole discretion.

Any acquisition we complete is subject to risks that could adversely affect our business, including the risk that our acquisitions may prove to be worth less than what we paid because of uncertainties in evaluating recoverable reserves and could expose us to potentially significant liabilities.
We have obtained a significant portion of our current reserve base through acquisitions of producing properties and undeveloped acreage. The success of any acquisition involves potential risks, including among other things:

- the inability to estimate accurately the costs to develop the reserves, recoverable volumes of reserves, rates of future production and future net cash flows attainable from the reserves;

- the assumption of unknown liabilities, including environmental liabilities, and losses or costs for which the Company is not indemnified or for which the indemnity the Company receives is inadequate;

- the effect on our liquidity or financial leverage of using available cash or debt to finance acquisitions; and

- the diversion of management's attention from other business concerns.

Successful acquisitions of oil and natural gas properties require an assessment of a number of factors, including estimates of recoverable reserves, the timing of recovering reserves, exploration potential, future commodity prices, operating costs and potential environmental, regulatory and other liabilities. Such assessments are inexact, and we cannot make these assessments with a high degree of accuracy. In connection with our assessments, we perform a review of the acquired properties that we believe to be generally consistent with industry practices. However, such a review may not reveal all existing or potential problems.
There may be threatened, contemplated, asserted or other claims against the acquired assets related to environmental, title, regulatory, tax, contract, litigation or other matters of which we are unaware, which could materially and adversely affect our production, revenues and results of operations. We are sometimes able to obtain contractual indemnification for pre-closing liabilities, including environmental liabilities, but we generally acquire interests in properties on an “as is” basis with limited remedies for breaches of representations and warranties.
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 and increased demand for labor, services and materials as drilling activity increases. Decreased levels of drilling activity in the oil and natural gas industry in recent periods have led to declining costs of some drilling equipment, materials and supplies. However, such costs may rise quickly if commodity prices, thereby negatively impacting our profitability, cash flow and ability to complete development activities as scheduled and on budget.
Certain of our properties are subject to land use restrictions, which could limit the manner in which we conduct our business.
Certain of our properties are subject to land use restrictions, including city ordinances, which could limit the manner in which we conduct our business. These land use restrictions could affect, among other things, our access to and the permissible uses of our facilities as well as the manner in which we produce oil and natural gas and may restrict or prohibit drilling in general. The costs we incur to comply with such restrictions may be significant in nature, and we may experience delays or curtailment in the pursuit of exploration, development or production activities and perhaps even be precluded from the drilling of wells.

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

The demand 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 both in high and low price environments. Historically, there have been shortages of drilling and workover rigs, pipe and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. Additionally, during periods of low prices, the labor pool may be reduced and equipment retired, causing shortages when activity levels pick up. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. 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. Equipment shortages could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

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

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

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 under existing provisions of the federal Clean Air Act that, among other things, require preconstruction and operating permits for certain large stationary sources. Facilities required to obtain preconstruction permits for their GHG emissions must meet “best available control technology” standards that will be established by the states or, in some cases, by the EPA on a case by case basis. These EPA rulemakings 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.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation 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 efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs. These programs typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. In addition, on May 12, 2016, the EPA issued a final rule establishing standards for the reduction of methane, a GHG, from new and existing sources in the oil and gas sector. 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. It remains unclear what actions, if any, the Trump administration will undertake related to GHG emissions. Substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce. 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 and other climatic events; if any such effects were to occur, they could have a material adverse effect on our exploration and production operations.

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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, sand and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations. Hydraulic fracturing is typically regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and published permitting guidance in February 2014 addressing the performance of such activities using diesel fuels. Also, in May 2014, the EPA issued an Advanced Notice of Proposed Rulemaking, seeking comment on the development of regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing. In addition, in March 2015, the BLM of the U.S. Department of the Interior published a final rule that imposes requirements for hydraulic fracturing activities on federal lands, including new requirements relating to public disclosure, as well as well bore integrity and handling of flowback water. Furthermore, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. It is unclear how any federal disclosure requirements that add to any applicable state disclosure requirements already in effect may affect our operations.

We may be subject to regulations that restrict our ability to discharge water produced as part of our production operations, and the ability to use injection wells as a disposal option not only will depend on federal or state regulations but also on whether available injection wells have sufficient storage capacities. In June 2016, the EPA issued a final rule banning the disposal of wastewater from unconventional oil and gas wells to public wastewater and sewage treatment plants. Produced and other flowback water from our current operations in the Permian Basin is typically not discharged to wastewater treatment plants but is re-injected into underground formations that do not contain potable water.

Further, the EPA has promulgated final rules that subject all oil and natural gas operations (production, processing, transmission, storage and distribution) to regulation under the NSPS and NESHAPS programs. These rules include NSPS standards for completions of hydraulically fractured gas wells. The standards include the reduced emission completion techniques developed in the EPA's Natural Gas STAR program along with pit flaring of gas not sent to the gathering line. The standards are applicable to newly drilled and fractured wells and wells that are refractured. Further, the rules under NESHAPS include Maximum Achievable Control Technology ("MACT") for glycol dehydrators and storage vessels at major source of hazardous air pollutants not currently subject to MACT standards. On May 12, 2016, the EPA issued three additional rules for the oil and gas industry to reduce emissions of methane, volatile organic compounds ("VOCs") and other compounds. These rules apply to all new, reconstructed, and modified processes and equipment since September 2015. Among other things, the new rules impose green completion requirements on new hydraulically fractured oil wells and reduce allowable emissions of methane and VOCs.

In addition, certain governmental reviews have been conducted or are underway that focus on the potential environmental impacts of hydraulic fracturing. For example, the EPA has completed a study of the potential environmental effects of hydraulic fracturing on water resources and published a final report in December 2016. Other governmental agencies, including the U.S. Department of Energy, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing and could ultimately make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

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, the Texas Railroad Commission has issued a "well integrity rule," that includes 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. In 2013, the Texas Railroad Commission implemented its hydraulic fracturing disclosure rule, which requires oil and gas operators to disclose on the FracFocus website the chemical ingredients and water volumes used in hydraulic fracturing treatments. 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 or prohibit the performance of well drilling in general or hydraulic fracturing in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, 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 exploration, development or production activities, and perhaps even be precluded from drilling wells.

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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 and maintain 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, market oil and natural gas and secure and maintain 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. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

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

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

We are susceptible to the potential difficulties associated with rapid growth and expansion and have a limited operating history.

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

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

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

Increases in the cost of capital 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. Recent and continuing disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

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

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

- recoverable reserves;
- future oil, NGL and natural gas prices and their applicable differentials;
- operating costs; and

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- potential environmental and other liabilities.

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

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

Potential legislation, if enacted into law, could make significant changes to U.S. federal and state income tax laws, including the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies. These changes include, but are not limited to: (i) the repeal of the percentage depletion allowance for oil and natural gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities for oil and natural gas production; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective.

The passage of this legislation or any other similar change in U.S. federal income tax law, as well as any similar changes in state law, could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could negatively affect our financial condition and results of operations. Additionally, future legislation could be enacted that increases the taxes or fees imposed on oil and natural gas extraction. Any such legislation could result in increased operating costs and/or reduced consumer demand for petroleum products, which in turn could affect the prices we receive for our oil, NGL and gas.

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

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

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

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

The enactment of derivatives legislation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

The Dodd-Frank Wall Street Reform and Consumer Protection Act (the “Dodd Frank Act”), enacted on July 21, 2010, established federal oversight and regulation of the over the counter derivatives market and entities, such as us, that participate in that market. The Dodd-Frank Act requires the CFTC and the Securities and Exchange Commission (the

"SEC") to promulgate rules and regulations implementing the Dodd-Frank Act. In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position limits rule was vacated by the United States District Court for the District of Columbia in September 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide derivative transactions. The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing. The CFTC has not yet proposed rules designating any other classes of swaps, including physical commodity swaps, for mandatory clearing. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished or what the effect of any such regulations will be on the Company. The full impact of the Dodd-Frank Act and related regulatory requirements upon the Company's business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks the Company encounters, and reduce the Company's ability to monetize or restructure its existing derivative contracts. If the Company reduces its use of derivatives as a result of the Dodd-Frank Act and regulations, the Company's results of operations may become more volatile and its cash flows may be less predictable, which could adversely affect the Company's ability to plan for and fund capital expenditures. 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. The Company's revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices. Any of these consequences could have a material and adverse effect on the Company and its financial condition.

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

Standardized measure is a reporting convention that provides a common basis for comparing oil and natural gas companies subject to the rules and regulations of the SEC. Standardized measure requires the use of specific pricing as required by the SEC as well as operating and development costs prevailing as of the date of computation. Consequently, it may not reflect the prices ordinarily received or that will be received for oil and natural gas production because of varying market conditions, nor may it reflect the actual costs that will be required to produce or develop the oil and natural gas properties. Accordingly, estimates included herein of future net cash flow may be materially different from the future net cash flows that are ultimately received. Therefore, the standardized measure of our estimated reserves included in this Report should not be construed as accurate estimates of the current fair value of our proved reserves.

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

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

The requirements of being a public company may strain our resources, increase our costs and distract management.

We completed our IPO in January 2014. As a public company, we incur significant legal, accounting and other expenses that we did not incur as a private company. We also incur costs associated with our public company reporting requirements and with corporate governance requirements, including requirements under the Sarbanes-Oxley Act of 2002, as well as rules implemented by the SEC and the Financial Industry Regulatory Authority. These rules and regulations have increased our legal and financial compliance costs and make some activities more time-consuming and costly. The rules and regulations also make it more difficult and more expensive for us to obtain director and officer liability insurance and we may be required to accept reduced policy limits and coverage or incur substantially higher costs to obtain the same or similar coverage. As a result, it may be more difficult for us to attract and retain qualified individuals to serve on our board of directors or as executive officers.

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We are subject to certain requirements of Section 404 of the Sarbanes-Oxley Act. If we fail to comply with the requirements of Section 404 or if we or our auditors identify and report material weaknesses in internal control over financial reporting, our investors may lose confidence in our reported information and our stock price may be negatively affected.

We are required to comply with certain provisions of Section 404 of the Sarbanes-Oxley Act of 2002, or Sarbanes-Oxley Act. Section 404 requires that we document and test our internal control over financial reporting and issue management's assessment of our internal control over financial reporting. This section also requires that our independent registered public accounting firm opine on those internal controls. If we fail to comply with the requirements of Section 404 of the Sarbanes-Oxley Act, or if we or our auditors identify and report material weaknesses in internal control over financial reporting, the accuracy and timeliness of the filing of our annual and quarterly reports may be materially adversely affected and could cause investors to lose confidence in our reported financial information, which could have a negative effect on the trading price of our common stock. In addition, a material weakness in the effectiveness of our internal control over financial reporting could result in an increased chance of fraud and the loss of customers, reduce our ability to obtain financing and require additional expenditures to comply with these requirements, each of which could have a material adverse effect on our business, results of operations and financial condition.

A small number of our stockholders hold a substantial portion of our outstanding common stock.

Five of our largest stockholders, Silver Hill Energy Partners Holdings, LLC, Collins, Wallace LP, The Vanguard Group, and Boston Partners (such stockholders collectively, the "Principal Investors") collectively hold approximately 33.2% of our common stock as of December 31, 2016 and their interests may conflict with those of other stockholders. Furthermore, in connection with the closing of our IPO, we entered into a stockholders' agreement with RSP Permian Holdco, L.L.C. (which has since assigned its rights and obligations thereunder to Production Opportunities II, L.P. ("Production Opportunities")), Collins, Wallace LP, Rising Star (which has since assigned its rights and obligations thereunder to Natural Gas Partners VIII, L.P.) and Pecos Energy Partners, L.P. The stockholders' agreement provides each of Collins and Wallace LP with the right to designate a nominee to our board of directors so long as each beneficially owns at least five percent of the outstanding shares of our common stock. The existence of significant stockholders and the stockholders' agreement may have the effect of deterring hostile takeovers, delaying or preventing changes in control or changes in management, or limiting the ability of our other stockholders to approve transactions that they may deem to be in the best interests of our company. Moreover, this concentration of stock ownership may adversely affect the trading price of our common stock to the extent investors perceive a disadvantage in owning stock of a company with significant stockholders.

Conflicts of interest could arise in the future between us, on the one hand, and our largest stockholders or their respective affiliates, on the other hand, concerning, among other things, potential competitive business activities or business opportunities.

Certain Principal Investors and certain of their affiliates have made and may continue to make investments in the U.S. oil and gas industry from time to time. As a result, our Principal Investors or their respective affiliates have and may, from time to time, acquire interests in businesses that directly or indirectly compete with our business, as well as businesses that are significant existing or potential customers. Our Principal Investors or their respective affiliates may acquire or seek to acquire assets that we seek to acquire and, as a result, those acquisition opportunities may not be available to us or may be more expensive for us to pursue.

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

Our revolving credit facility limits the amounts we can borrow up to a borrowing base amount, which the lenders, in their sole discretion, determine on a semi annual basis based, among other things, upon projected revenues from, and asset values of, the oil and natural gas properties securing our loan. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our revolving credit facility. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments. The borrowing base under our revolving credit facility is currently $950 million, with lender commitments of $2 billion.

In the future, we may not be able to access adequate funding under our revolving credit facility as a result of a decrease in borrowing base due to the issuance of new indebtedness, the outcome of a subsequent borrowing base redetermination or an unwillingness or inability on the part of lending counterparties to meet their funding obligations and the inability of other lenders to provide additional funding to cover the defaulting lender’s portion. Declines in commodity prices could result in a determination to lower the borrowing base in the future and, in such a case, we could be required to repay any indebtedness in excess of the redetermined borrowing base. As a result, we may be unable to implement our 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.

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

If our cash flows and capital resources are insufficient to fund debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance indebtedness. Our ability to restructure or refinance indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict business operations. The terms of existing or future debt instruments may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet debt service and other obligations. Our revolving credit facility and indentures governing the senior notes currently restricts our ability to dispose of assets and our use of the proceeds from such disposition. 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.

The borrowing base under our revolving credit facility is currently $950 million and the Company elected commitment amount is $900 million. Provided that the SHEP II acquisition closes before May 1, 2017, our borrowing base will increase to $1.1 billion and our next borrowing base redetermination will be in November 2017. In the future, we may not be able to access adequate funding under our revolving credit facility as a result of a decrease in borrowing base due to the issuance of new indebtedness, the outcome of a subsequent borrowing base redetermination or an unwillingness or inability on the part of lending counterparties to meet their funding obligations and the inability of other lenders to provide additional funding to cover the defaulting lender’s portion. Declines in commodity prices could result in a determination to lower the borrowing base in the future and, in such a case, we could be required to repay any indebtedness in excess of the redetermined borrowing base. As a result, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out business plans, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

Our leverage and debt service obligations may adversely affect our financial condition, results of operations, business prospects and our ability to make payments on our debt obligations.

As of December 31, 2016, we had $1.15 billion of senior unsecured notes outstanding, $0.6 million of letters of credit outstanding under our revolving credit facility, and $899.4 million of borrowing capacity under our revolving credit facility. Our level of indebtedness could affect our operations in several ways, including the following:

- require us to dedicate a substantial portion of our cash flow from operations to service our existing debt, thereby reducing the cash available to finance our operations and other business activities;
- limit management’s discretion in operating our business and our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate;
- increase our vulnerability to downturns and adverse developments in our business and the economy generally;
- limit our ability to access the capital markets to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness;
- place restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;

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- make it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a portion of our then outstanding bank borrowings;
- make us vulnerable to increases in interest rates as our indebtedness under our revolving credit facility may vary with prevailing interest rates;
- place us at a competitive disadvantage relative to competitors with lower levels of indebtedness in relation to their overall size or less restrictive terms governing their indebtedness; and
- make it more difficult for us to satisfy our obligations under our debt instruments and increase the risk that we may default on our debt obligations.

We may still be able to incur substantial additional indebtedness, which could increase the risks we face.

Subject to the restrictions in our credit facility and indentures governing the senior notes, we may incur substantial additional indebtedness (including secured indebtedness) in the future. Although our credit facility and indentures governing the senior notes contain restrictions on the incurrence of additional indebtedness, these restrictions are subject to waiver and a number of significant qualifications and exceptions, and indebtedness incurred in compliance with these restrictions could be substantial.

Any increase in our level of indebtedness will have several important effects on our future operations, including, without limitation, whether:

- we will have additional cash requirements in order to support the payment of interest on our outstanding indebtedness;
- increases in our outstanding indebtedness and leverage will increase our vulnerability to adverse changes in general economic and industry conditions, as well as to competitive pressure; and
- depending on the levels of our outstanding indebtedness, our ability to obtain additional financing for working capital, capital expenditures, general corporate and other purposes may be limited.

We cannot assure you that we will be able to maintain or improve our leverage position.

An element of our business strategy involves maintaining a disciplined approach to financial management. However, we are also seeking to acquire, exploit and develop additional reserves that may require the incurrence of additional indebtedness. Although we will seek to maintain or improve our leverage position, our ability to maintain or reduce our level of indebtedness depends on a variety of factors, including future performance and our future debt financing needs. General economic conditions, oil, NGL and natural gas prices and financial, business and other factors will also affect our ability to maintain or improve our leverage position. Many of these factors are beyond our control.

Our revolving credit facility and the indentures governing the senior notes have restrictive covenants that could limit our growth, financial flexibility and our ability to engage in certain activities.

Our revolving credit facility and the indentures governing the senior notes have restrictive covenants that could limit our growth, financial flexibility and our ability to engage in activities that may be in our long term best interests. Our revolving credit facility and the indentures governing the senior notes contain covenants, that, among other things, limit our ability to:

- incur additional indebtedness;
- make loans to others;
- make investments;
- merge or consolidate with another entity;
- make dividends and certain other payments;
- hedge future production or interest rates;

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- create liens that secure indebtedness;
- sell assets;
- enter into transactions with affiliates; and
- engage in certain other transactions without the prior consent of the lenders.

In addition, our revolving credit facility requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios, which may 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 these limitations.

Our failure to comply with these covenants could result in an event of default that, if not cured or waived, could result in the acceleration of all of our indebtedness. 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 we are unable to comply with the restrictions and covenants in the agreements governing our indebtedness, there could be a default under the terms of these agreements, which could result in an acceleration of payment of funds that we have borrowed.

If we are unable to generate sufficient cash flow and are otherwise unable to obtain funds necessary to meet required payments of principal, premium, if any, and interest, or special interest, if any, on our indebtedness, or if we otherwise fail to comply with the various covenants, including financial and operating covenants, in the agreements governing our indebtedness, we could be in default under the terms of the agreements governing such indebtedness. In the event of such default:

the holders of such indebtedness could elect to declare all the funds borrowed thereunder to be due and payable, together with accrued and unpaid interest;

the lenders under our revolving credit facility could elect to terminate their commitments thereunder, cease making further loans and institute foreclosure proceedings against our assets; and

we could be forced into bankruptcy or liquidation.

If our operating performance declines, we may in the future need to obtain waivers under our revolving credit facility to avoid being in default. If we breach our covenants under our revolving credit facility and seek a waiver, we may not be able to obtain a waiver from the required lenders. If this occurs, we would be in default under our revolving credit facility, the lenders could exercise their rights, as described above, and we could be forced into bankruptcy or liquidation.

A downgrade in our credit rating could negatively impact our cost of and ability to access capital.

We receive debt credit ratings from Standard & Poor’s Ratings Group, Inc. (“S&P”) and Moody’s Investors Service, Inc. (“Moody’s”), which are subject to regular reviews. S&P and Moody’s consider many factors in determining our ratings including: production growth opportunities, liquidity, debt levels and asset and reserve mix.

A downgrade in our credit ratings could negatively impact our costs of capital and our ability to effectively execute aspects of our strategy. Further, a downgrade in our credit ratings could affect our ability to raise debt in the public debt markets, and the cost of any new debt could be much higher than our outstanding debt. These and other impacts of a downgrade in our credit ratings could have a material adverse effect on our business, financial condition and results of operations.

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ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Our properties as of December 31, 2016 include working interests in approximately 139,000 gross and 84,000 net surface acres located in the Permian Basin primarily in the Texas counties of Midland, Martin, Andrews, Ector, Glasscock, Dawson, Loving and Winkler.

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. It is composed of three sub basins, the Delaware Basin, the Central Basin Platform and the Midland Basin. Both the Midland Basin and the Delaware Basin are characterized by extensive operating histories, favorable operating environments, available infrastructure and a well-developed network of oilfield service providers, long reserve lives, multiple producing horizons, and a large number of operators. The first commercial wells were drilled in both basins during the 1920's. Advances in geologic understanding and production technology have highlighted the resource potential of these basins unconventional reservoirs that are productive after hydraulic-fracture stimulation. Technological advances in 3-D seismic imagery have demonstrated the larger geographic extent of the unconventional formations than originally estimated and, due to multiple stacked pay zones, significantly more oil in place as compared to other major U.S. shale oil plays. In recent years, drilling activity in the Permian Basin has shown a growing trend towards horizontal and directional drilling over vertical drilling.

The vast majority of our acreage is located on large, contiguous acreage blocks in the core of the Midland Basin and Delaware Basin. The Midland Basin properties are primarily in the adjacent Texas counties of Midland, Martin, Andrews, Ector, Glasscock, and Dawson. The Delaware Basin properties are located in the adjacent Texas counties of Loving and Winkler. We believe that our properties are prospective for oil and liquids-rich natural gas from multiple producing stratigraphic horizons, which we refer to as stacked pay zones.

As of December 31, 2016 we had identified 5,003 horizontal drilling locations, which include properties acquired in the SHEP I acquisition in November 2016 in multiple horizons across our acreage. Including the properties expected to be acquired in the SHEP II acquisition, expected to close in March 2017, our pro forma identified horizontal drilling locations was 5,930. We define identified drilling locations as locations specifically identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic and engineering data. The availability of local infrastructure, drilling support assets and other factors as management may deem relevant, such as easement restrictions and state and local regulations, are considered in determining such locations. The drilling locations on which we actually drill wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results and other factors.

Our contiguous acreage positions allow us to drill longer laterals, maximize our resource recovery on a per section basis and increase our returns. In addition, our contiguous acreage positions allow us the flexibility to adjust our drilling and completion techniques, primarily the length of our horizontal laterals, in order to maximize our well results, drilling costs and returns. Our contiguous acreage positions and owning leases covering virtually all of the depths of our properties allow us to target multiple horizontal zones underneath our surface acreage. Including the SHEP II acreage, our total pro forma Effective Horizontal Acreage is approximately 502,000 net acres when considering the multiple zones under the surface acreage in our core areas, which we believe more accurately conveys the extent of our horizontal drilling opportunities in our target zones.

Estimated proved reserves, net to our interest, in our properties, as of December 31, 2016, which include properties acquired in the SHEP I acquisition in November 2016 and have been reviewed by Netherland Sewell, our independent petroleum engineering firm, were approximately 236.9 MMBoe (70% oil, 12% natural gas, and 18% NGLs), of which 41% were classified as PDP. The estimated proved reserves are generally characterized as long-lived, with predictable production profiles. Including the properties expected to be acquired in the SHEP II acquisition, expected to close in March 2017, our pro forma proved reserves were approximately 283.3 MMBoe (70% oil, 12% natural gas, and 18% NGLs), of which 39% were classified as PDP.

Production Status. For the year ended December 31, 2016, our average net daily production was 29,161 Boe/d (approximately 73% oil, 16% NGLs and 11% natural gas), of which 77% was from horizontal well production and 23% was from vertical well production. For the year ended December 31, 2015, our average net daily production was 21,047 Boe/d

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(approximately 75% oil, 14% NGLs and 11% natural gas). As of December 31, 2016, we operated and produced from 233 horizontal and 402 vertical wells and were the operator of approximately 81% of our net acreage.

Facilities. We strive to develop the necessary infrastructure to lower our costs and support our drilling schedule and production growth. We accomplish this goal through a combination of developing a portion of our own midstream assets as well as through contractual arrangements with third party service providers. Our facilities located on our properties are generally in close proximity to our well locations and include storage tank batteries, oil/gas/water separation equipment and pumping units.

In addition to standard well site surface equipment, we have invested our capital in building gathering lines and water infrastructure, including water pipelines, water source wells and water disposal wells to support our exploration and development activities. To secure adequate water supplies, we have drilled water source wells into the Santa Rosa formation in West Texas that complement our purchase of fresh water. A majority of the water used in our operations is sourced from the Santa Rosa formation, which is a brackish, non-potable water aquifer that is not used for human consumption or agricultural use but is of adequate quality for our hydraulic fracturing operations. We also operate saltwater disposal wells on our properties. We have a minority investment in a small private midstream company that engages in the building and operation of water infrastructure on our properties, and for third parties.

Oil and Natural Gas Data

Proved Reserves

Evaluation and Review of Proved Reserves. Our proved reserve estimates as of December 31, 2016 and the proved reserve estimates associated with SHEP II as of December 31, 2016 were prepared by Netherland Sewell, our independent petroleum engineers. The technical persons responsible for preparing our proved reserve estimates set forth in the Netherland Sewell letters 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. Netherland Sewell does not own an interest in any of our properties, nor is it employed by us on a contingent basis. A copy of each of the independent petroleum engineering firm’s proved reserve reports as of December 31, 2016 is included as an exhibit to this Report.

We maintain an internal staff of petroleum engineers and geoscience professionals who worked closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of the data used to calculate our proved reserves relating to our assets in the Permian Basin. Our internal technical team members meet with our independent reserve engineers periodically during the period covered by the proved reserve report to discuss the assumptions and methods used in the proved reserve estimation process. We provide historical information to Netherland Sewell for our properties, such as ownership interest, oil and natural gas production, well test data, commodity prices and operating and development costs. Our Reservoir Engineering Manager is primarily responsible for overseeing the preparation of all of our reserve estimates. He is a petroleum engineer with over 13 years of reservoir and operations experience, and our geoscience staff has an average of approximately 20 years of energy industry experience per person.

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

- review and verification of historical production data, which data is based on actual production as reported by us;
- preparation of reserve estimates by our Reservoir Engineering Manager or under his direct supervision;
- review by our Chief Executive Officer of all of our reported proved reserves at the close of each quarter, including the review of all significant reserve changes and all new PUDs additions;

•direct reporting responsibilities by our Reservoir Engineering Manager to our Chief Operating Officer; and
•verification of property ownership by our land department.

Estimation of Proved Reserves. Under SEC rules, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—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, 2016, 2015 and 2014 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the

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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 relatively high degree of accuracy. Non-producing reserve estimates, for developed and undeveloped properties, were forecast using either volumetric or analogy methods, or a combination of both. These methods provide a relatively high degree of accuracy for predicting proved developed non-producing and PUDs for our properties, due to the mature nature of the properties targeted for development and an abundance of subsurface control data.

To estimate economically recoverable proved reserves and related future net cash flows, many factors and assumptions, including the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates were considered.

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 has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves have been demonstrated to yield results with consistency and repeatability, and include production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, available seismic data and historical well cost and operating expense data.

Summary of Oil and Natural Gas Reserve Estimates. The following table presents our estimated net proved oil and natural gas reserves as of December 31, 2016, 2015, and 2014, as well as our pro forma net proved oil and natural gas reserves, after giving effect to the SHEP II acquisition as if it had occurred on January 1, 2016, as of December 31, 2016, in each case, prepared in accordance with the rules and regulations of the SEC. All of our proved reserves are located in the United States. Copies of the December 31, 2016 reserve reports by Netherland Sewell covering our proved reserves and the SHEP II proved reserves are included as exhibits to this Report.

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	Year ended December 31,			
	2016	2015	2014	Pro Forma 2016
Proved developed reserves:				
Oil (MBbls)	65,025	44,128	27,716	75,341
Natural gas (MMcf)	76,255	56,640	35,921	86,475
NGLs (MBbls)	18,759	11,020	8,221	20,864
Total (MBoe)	96,493	64,588	41,924	110,617
Proved undeveloped reserves:				
Oil (MBbls)	99,703	67,007	41,557	123,601
Natural gas (MMcf)	100,531	76,867	56,501	122,959
NGLs (MBbls)	23,937	14,767	13,518	28,575
Total (MBoe)	140,395	94,585	64,492	172,669
Total proved reserves:				
Oil (MBbls)	164,728	111,135	69,273	198,942
Natural gas (MMcf)	176,786	133,507	92,422	209,434
NGLs (MBbls)	42,696	25,787	21,739	49,439
Total (MBoe)	236,888	159,173	106,416	283,286

The changes from December 31, 2015 estimated proved reserves to December 31, 2016 estimated proved reserves reflect production during this period of approximately 10,673 MBoe, net downward revisions of approximately 17,750 MBoe, additions due to acquisitions of 40,900 MBoe which included our acquisition of SHEP I that closed in November 2016, and additions of approximately 65,238 MBoe attributable to extensions resulting from drilling of wells by us to delineate our acreage position. The negative revision of previous estimated quantities was mainly due to the removal of certain vertical PUDs, as these locations will be replaced with horizontal wells when drilled in the future. The negative revisions of previous estimated quantities due to pricing were 2,131 MBoe.

The changes from December 31, 2014 estimated proved reserves to December 31, 2015 estimated proved reserves reflect production during this period of approximately 7,682 MBoe, net downward revisions of approximately 20,505 MBoe, additions due to acquisitions of 14,379 MBoe, and additions of approximately 66,565 MBoe attributable to extensions resulting from drilling of wells by us to delineate our acreage position. The negative revisions of previous estimated quantities due to pricing were 19,641 MBoe.

On a pro forma basis, the changes from our actual December 31, 2016 estimated proved reserves to our pro forma December 31, 2016 estimated proved reserves reflect additions of 46,398 due to the acquisition of SHEP II, which is expected to close in March 2017.

Reserve engineering is 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 "Item 1. Risk Factors."

Additional information regarding our proved reserves can be found in the notes to our financial statements included elsewhere in this Report and the proved reserve reports as of December 31, 2016, which are included as exhibits to this Report.

PUDs

Year Ended December 31, 2016

As of December 31, 2016, our PUDs totaled 99,703 MBbls of oil, 23,937 MBbls of NGLs and 100,531 MMcf of natural gas, for a total of 140,395 MBoe. PUDs will be converted from undeveloped to developed as the applicable wells begin production. Changes in PUDs that occurred during 2016 were primarily due to:

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•additions of approximately 47,225 MBoe attributable to extensions resulting from drilling of wells by us to delineate our acreage position;

•additions of approximately 28,512 MBoe attributable to acquisitions, which included our acquisition of SHEP I that closed in November 2016; and

•the conversion of approximately 8,487 MBoe attributable to PUDs into proved developed reserves, and

•net reductions of approximately 21,440 from negative revisions of previous estimated quantities which were primarily due to negative revisions due to the removal of certain vertical PUDs as these locations will be replaced with horizontal wells when drilled in the future, along with negative revisions due to pricing of 244 MBoe.

During the year ended December 31, 2016 , we spent $68.2 million to convert PUDs to proved developed reserves.

All of our PUD drilling locations are scheduled to be drilled within five years of their initial booking.

As of December 31, 2016, less than 1% of our total proved reserves were classified as proved developed non-producing.

Oil and Natural Gas Production Prices and Costs

Production and Price History

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

	RSP Permian, Inc. Years ended December 31,		
	2016	2015	2014 (1)
Production data:			
Oil (MBbls)	7,790	5,805	3,049
Natural gas (MMcf)	7,188	4,991	2,974
NGLs (MBbls)	1,685	1,045	718
Total (MBoe)	10,673	7,682	4,263
Average net daily production (Boe/d)	29,161	21,047	11,679
Average prices before effects of hedges(1)(2):			
Oil (per Bbl)	$41.28	$45.36	$83.10
Natural gas (per Mcf)	1.94	2.11	3.55
NGLs (per Bbl)	10.87	9.75	25.04
Total (per Boe)	33.15	$36.97	$66.13
Average realized prices after effects of hedges(3)(4):			
Oil (per Bbl)	41.06	$61.22	$85.01
Natural gas (per Mcf)	1.94	2.11	3.59
NGLs (per Bbl)	10.87	9.75	25.04
Total (per Boe)	32.99	$48.96	$67.53
Average costs (per Boe):			
Lease operating expenses (excluding gathering and transportation)	$4.93	$6.46	$7.49
Gathering and transportation	0.48	0.46	0.65
Production and ad valorem taxes	2.03	2.60	4.63
Depreciation, depletion and amortization	18.21	20.05	20.61
Components of general and administrative expense:			
General and administrative - cash component (5)	$2.10	$2.33	$4.25
General and administrative - (non IPO stock comp) (6)	1.23	1.03	0.64
General and administrative - (IPO stock comp) (7)	—	0.19	4.11
General and administrative - non-recurring stock comp (8)	0.06	—	—
Total general and administrative	3.39	3.55	9.00

(1) Represents information with respect to our predecessor for the first 22 days of 2014 plus that of RSP Permian, Inc. for the remainder of the year. Our predecessor reflects the combined results of RSP LLC and Rising Star.
(2) Does not include the results related to the acquisition of working interests from Pecos in 2014 (the "Pecos Contribution") due to its lack of significance to our financial results.
(3) Average prices shown in the table reflect prices both before and after the effects of our cash payments/receipts on our commodity derivative transactions. Our calculation of such effects includes realized gains or losses on cash settlements for commodity derivative transactions and an adjustment to reflect premiums incurred previously or upon settlement that are attributable to instruments settled in the period if applicable.
(4) Average realized prices for oil are net of transportation costs. Average realized prices for natural gas do not include transportation costs; instead, transportation costs related to our gas production and sales are included in our lease operating expenses. No transportation costs are associated with NGL production and sales.

(5) Amount includes all cash corporate general and administrative expenses, including cash compensation amounts. Certain IPO bonus amounts were recognized in the 2014 actual results which increased the general and administrative - cash component per Boe and these expenses were non-recurring. See the discussion of general and administrative expenses in "Part II, Item 7. Management's Discussion and Analysis of Financial Condition-Results of Operations.
(6) Represents compensation expense related to restricted stock awards and performance share awards granted as part of the Company's ongoing compensation and retention program.

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(7) IPO stock comp consists of two components. One component represents restricted stock awarded to certain employees as a result of a successful IPO. These one-time awards vest over time for retention purposes. The other component represents non-cash compensation expense associated with incentive units owned by certain members of management. These incentive units determined the stock allocation between management and Natural Gas Partners and had no dilutive impact or cash impact to the Company. See the discussion of incentive units in Note 8-Equity Based Compensation of Notes to Consolidated Financial Statements included in "Part II, Item 8. Financial Statements and Supplementary Data."
(8) The non-recurring 2016 amount is a compensation charge associated with the retirement of an officer of the Company.

Productive Wells

As of December 31, 2016 we owned an interest in 959 gross (534 net) productive wells, which include properties acquired in the SHEP I acquisition in November 2016. Including the properties expected to be acquired in the SHEP II acquisition, expected to close in March 2017, our pro forma interest was in 990 gross (562 net) productive wells. Our wells are oil wells which produce associated liquids-rich natural gas. Productive wells consist of producing wells and wells capable of production, including natural gas wells awaiting pipeline connections to commence deliveries and 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.

Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2016 relating to our leasehold acreage:

	Developed acreage(1)		Undeveloped acreage(2)		Total acreage	
	Gross	Net	Gross	Net	Gross	Net
Midland Basin	36,723	20,514	47,314	36,839	84,037	57,353
Delaware Basin (3)	1,640	841	52,956	25,792	54,596	26,633
Total	38,363	21,355	100,270	62,631	138,633	83,986
Delaware Basin (4)	1,240	1,124	19,990	12,298	21,230	13,422
Pro Forma Total	39,603	22,479	120,260	74,929	159,863	97,408

(1) Developed acres are acres spaced or assigned to productive wells and does not include undrilled acreage held by production under the terms of the lease.
(2) Undeveloped acres are 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.
(3) Includes properties acquired in the SHEP I acquisition in November 2016.
(4) Includes properties expected to be acquired in the SHEP II acquisition in March 2017.

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, 2016, 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.

	2017		2018		2019		2020		2021	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net

Midland Basin	25,206	15,972	10,944	3,032	1,606	109	—	—	—	—
Delaware Basin (1)	26,082	13,665	18,466	2,138	6,920	593	—	—	—	—
Delaware Basin (2)	19,308	12,906	5,748	445	5,488	1,075	—	—	—	—

(1) Includes properties acquired in the SHEP I acquisition in November 2016.

(2) Includes properties expected to be acquired in the SHEP II acquisition in March 2017.

Drilling Results

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The table below sets forth the results of our drilling activities for the periods indicated. The information should not be considered indicative of future performance, nor should it be assumed that there is necessarily any correlation among the number of productive wells drilled, quantities of reserves found or economic value. Productive wells are those that produce, or are capable of producing, commercial quantities of hydrocarbons, regardless of whether they produce a reasonable rate of return.

Dry wells are those that prove to be incapable of producing hydrocarbons in sufficient quantities to justify completion. Although a well may be classified as productive upon completion, future changes in oil and natural gas prices, operating costs and production may result in the well becoming uneconomical, particularly exploratory wells where there is no production history.

	RSP Permian, Inc.					
	For the Year Ended December 31,					
	2016		2015		2014 (1)	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive(1)	1.0	0.9	—	—	2.0	1.7
Dry	—	—	—	—	—	—
Total Exploratory	1.0	0.9	—	—	2.0	1.7
Development Wells:						
Productive(1)	85.0	47.7	118.0	63.6	147.0	84.1
Dry	—	—	—	—	—	—
Total Development	85.0	47.7	118.0	63.6	147.0	84.1
Total Wells:						
Productive(1)	86.0	48.6	118.0	63.6	149.0	85.8
Dry	—	—	—	—	—	—
Total	86.0	48.6	118.0	63.6	149.0	85.8

(1) Represents information with respect to our predecessor for the first 22 days of 2014 plus that of RSP Permian, Inc. for the remainder of the year. Our predecessor reflects the combined results of RSP LLC and Rising Star.

ITEM 3. LEGAL PROCEEDINGS

From time to time, we are party to ongoing legal proceedings in the ordinary course of business, including workers' compensation claims and employment related disputes. While the outcome of these proceedings cannot be predicted with certainty, we do not believe the results of these proceedings, individually or in the aggregate, if decided adversely against us will have a material adverse effect on our business, financial condition, results of operations or liquidity.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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

Market Information

The Company’s common stock is listed and traded on the NYSE under the symbol “RSPP.” The table below sets forth, for the periods indicated, the high and low sales prices per share of our common stock.

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	2016			
Low	$16.74	$27.19	$33.14	$34.93
High	$30.14	$36.50	$40.74	$46.44
	2015			
Low	$21.62	$25.13	$19.20	$20.52
High	$29.88	$31.15	$28.28	$30.38

On February 24, 2017, the Company's common stock was held by 9 shareholders of record. This number excludes owners for whom common stock may be held in “street” name.

Dividends

We have not paid any cash dividends since our inception. We currently intend to retain all future earnings for the development and growth of our business, and we do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future. Our future dividend policy is within the discretion of our board of directors and will depend upon then-existing conditions, including our results of operations, financial condition, capital requirements, investment opportunities, statutory restrictions on our ability to pay dividends and other factors our board of directors may deem relevant. In addition, our revolving credit facility and the indenture governing the notes restrict our ability to pay cash dividends.

ITEM 6. SELECTED FINANCIAL DATA

The following tables set forth selected consolidated financial data of the Company, selected historical consolidated financial data of our predecessor and selected pro forma combined financial data of RSP Permian, Inc. for the years indicated and as of the dates indicated. Our predecessor reflects the combined results of RSP LLC and Rising Star. For more information regarding our predecessor, see “Part II. Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations-Our Predecessor and RSP, Inc.”

The selected historical consolidated financial data of our predecessor as of and for the years ended on December 31, 2013 and 2012 were derived from audited historical financial statements of our predecessor. The selected financial data of the Company for the year ended December 31, 2014 were derived from audited historical financial statements of our predecessor (for the first 22 days of 2014) and audited financial statements of the Company (for the remainder of 2014). The selected financial data of the Company for the years ended December 31, 2015 and 2016, and as of December 31, 2016, 2015, and 2014 were derived from audited financial statements of the Company.

The selected unaudited pro forma combined financial data assumes that our IPO and the IPO Transactions (other than the Pecos Contribution due to its insignificance to our combined financial results) had taken place on January 1, 2013. The pro forma financial data for the year ended December 31, 2014 also reflects adjustments for non-recurring expenses associated with the IPO.

Our historical results are not necessarily indicative of future operating results. The selected financial data presented below are qualified in their entirety by reference to, and should be read in conjunction with, “Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and the consolidated financial statements of the Company included in this Report.

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	RSP Permian, Inc.					RSP Permian, Inc. Pro Forma	
	Year Ended December 31,					Year Ended December 31,	
	2016	2015	2014 (1)	2013	2012	2014 (Unaudited)	2013
	(In thousands, except per share data)						
Statement of Operations Data:							
Revenues:							
Oil sales	$321,588	$263,286	$253,371	$110,345	$91,441	$ 257,830	$ 177,415
Natural gas sales	13,945	10,517	10,572	5,383	4,284	10,762	7,647
NGL sales	18,324	10,189	17,982	7,314	8,702	18,317	11,644
Total revenues	$353,857	$283,992	$281,925	$123,042	$104,427	$ 286,909	$ 196,706
Operating expenses:							
Lease operating expenses	$57,778	$53,124	$34,704	$14,113	$12,693	$ 35,398	$ 22,667
Production and ad valorem taxes	21,615	19,995	19,758	8,326	7,575	20,009	13,236
Depreciation, depletion and amortization	194,360	154,039	87,844	47,158	48,803	91,477	80,487
Exploration	1,093	2,380	3,854	551	161	3,854	551
Asset retirement obligation accretion	472	336	142	121	115	151	199
Impairments (2)	4,901	34,269	4,344	—	—	4,344	—
General and administrative expenses	36,170	27,317	38,357	3,852	2,859	17,619	3,716
Acquisition Costs	6,374	—	—	—	—	—	—
Total operating expenses	322,763	291,460	189,003	74,121	72,206	172,852	120,856
(Gain) loss on sale of assets	—	306	13	(22,700)	(6,734)	13	—
Operating income (loss)	$31,094	$(7,774)	$92,909	$71,621	$38,955	$ 114,044	$ 75,850
Other income (expense):							
Other income (expenses), net	$1,833	$469	$(44)	$1,202	$884	$ (44)	$ 1,202
Gain (loss) on derivative instruments	(23,760)	20,906	81,470	(2,607)	(796)	81,470	(2,607)
Interest expense	(52,724)	(43,538)	(14,031)	(5,216)	(3,474)	(14,031)	(10,890)
Total other income (expense)	$(74,651)	$(22,163)	$67,395	$(6,621)	$(3,386)	$ 67,395	$ (12,295)
Income (loss) before taxes	(43,557)	(29,937)	160,304	65,000	35,569	181,439	63,555
Income tax (expense) benefit	18,706	11,683	(157,806)	(2,262)	339	(65,318)	(22,717)
Net Income (loss)	$(24,851)	$(18,254)	$2,498	$62,738	$35,908	$ 116,121	$ 40,838
Pro Forma Per share data (unaudited):							
Net earnings per common share:							
Basic and diluted						$ 1.55	$ 0.56
Weighted average common shares outstanding:							
Basic and diluted						74,297	72,500
Pro Forma C Corporation Data (unaudited)(3):							

Net income before taxes			$160,304	$62,738	
Pro forma income taxes			(57,709)	(22,586)	
Pro forma net income			$102,595	$40,152	
Cash Flow Data:					
Net cash provided by operating activities	$166,213	$218,805	$223,157	$73,345	$72,803
Net cash used in investing activities	(1,029,423)	(874,939)	(816,925)	(119,591)	(113,220)
Net cash provided by financing activities	1,411,245	742,583	636,826	8,248	81,583

(1) Represents our predecessor’s historical financial data for the first 22 days of 2014 plus RSP Permian, Inc.'s historical financial data for the remainder of the year.

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(2) Impairments in 2014 and 2016 primarily relate to unproved properties where lease terms expired. Impairments in 2015 relate primarily to write downs of the value of proved properties in Dawson County, where these properties were deemed impaired based upon impairment testing under successful efforts accounting, along with impairments on unproved properties where lease terms expired.
(3) RSP LLC was formed as a holding company in October 2010, and did not conduct any material business operations until December 2010. RSP Permian, Inc. is a C-Corp. under the Internal Revenue Code of 1986, as amended, and is subject to income taxes. The Company computed a pro forma income tax provision for 2013 and 2014 as if our predecessor was subject to income taxes as a C-Corp. since January 1, 2013. The unaudited pro forma data is presented for informational purposes only and does not purport to project our results of operations for any future period or our financial position as of any future date. The pro forma tax provision has been calculated at a rate based upon a federal corporate level tax rate and a state tax rate, net of federal benefit, incorporating permanent differences.

	Year Ended December 31,				
	2016	2015	2014	2013	2012
	(In thousands)				
Balance Sheet Data:					
Cash and cash equivalents	$690,776	$142,741	$56,292	$13,234	$51,232
Other current assets	85,486	44,799	117,450	33,901	31,124
Total current assets	776,262	187,540	173,742	47,135	82,356
Property, plant and equipment, net	4,129,635	2,758,630	2,094,618	516,288	421,412
Other long-term assets	90,530	21,263	10,551	24,232	9,470
Total assets	$4,996,427	$2,967,433	$2,278,911	$587,655	$513,238
Current liabilities	108,269	77,402	104,252	30,866	28,165
Long-term debt	1,132,275	686,512	488,964	128,155	111,586
NPI payable	—	—	—	36,931	16,583
Other long-term liabilities	339,155	344,935	359,924	4,822	3,061
Total stockholders'/members’ equity	3,416,728	1,858,584	1,325,771	386,881	353,843
Total liabilities and stockholders'/members’ equity	$4,996,427	$2,967,433	$2,278,911	$587,655	$513,238

Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes in “Part II, Item 8. Financial Statements and Supplementary Data.” The following discussion and analysis contains forward-looking statements, including, without limitation, statements relating to our plans, strategies, objectives, expectations, intentions and resources. Please see “Cautionary Statement Concerning Forward-Looking Statements” and “Part I, Item 1A. Risk Factors” in this Report.

Our Predecessor and RSP Inc.

RSP Inc. was formed in September 2013 and, prior to the consummation of our IPO in January 2014, did not have historical financial operating results. The historical results of RSP LLC and Rising Star Energy Development Co., L.L.C. , our predecessor, have been consolidated for all periods presented prior to the IPO date. In connection with the IPO, pursuant to the terms of a corporate reorganization, RSP LLC became a wholly-owned subsidiary of RSP Inc. RSP LLC was formed in 2010 to engage in acquisition, exploration, development, and production of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin of West Texas. Also in connection with the IPO, Rising Star contributed to RSP Inc. certain assets that represent substantially all of Rising Star’s production and revenues for each of the years ended December 31, 2013 and 2012 in exchange for shares of RSP Inc.’s common stock and cash.

Overview and Outlook

Our financial and operating performance and significant events in 2016 included the following highlights:

- Increased our average daily production rate 39% for the year ended December 31, 2016 as compared to the same period in 2015.

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- Decreased our cash operating costs on a per Boe basis 19% from $11.85 to $9.54 in 2016 as compared to 2015. These costs include lease operating expense, production and ad valorem taxes, and general and administrative expense (excluding equity based compensation expense).
- In October 2016, entered into definitive agreements to acquire Silver Hill Energy Partners, LLC ("SHEP I") and Silver Hill E&P II, LLC ("SHEP II", and together with SHEP I, "Silver Hill") for $1.25 billion of cash and 31.0 million shares of RSP Inc. common stock in aggregate, implying a total purchase price of approximately $2.4 billion (based on the 20-day volume weighted average price of RSP Inc. common stock). Silver Hill is comprised of two privately-held entities that collectively own oil and gas producing properties and undeveloped acreage in Loving and Winkler counties in Texas. The SHEP I acquisition closed in November 2016, and the SHEP II acquisition is expected to close in March 2017.
- Also in October 2016, completed an underwritten public offering of 25.3 million shares of RSP Inc. common stock, including the exercise of the underwriter's option to purchase additional shares, raising approximately $1 billion in net proceeds after deducting underwriting discounts and commissions and estimated offering expenses paid by the Company. The proceeds from the equity offering were used to fund the cash purchase price of the SHEP I acquisition and pay down the existing balance on the revolving credit facility.
- In December 2016, issued $450 million of 5.25% senior unsecured notes due 2025 at par in a private placement. The proceeds from the notes offering are expected to be used to fund a portion of the cash purchase price of the SHEP II acquisition.
- Also in December 2016, amended our revolving credit facility to increase the borrowing base from $600 million to $950 million, extend the maturity date to December 2021, update key financial covenants and increase the maximum commitments of the lenders from $1.0 billion to $2.5 billion.
- Acquired approximately $69 million of additional oil and gas properties in the Midland Basin.

Our average daily production rate during 2016 was 29,161 Boe/d, a 39% increase from 2015 average daily production of 21,047 Boe/d. Oil production was 73% of total production on a volumetric basis and oil sales were 91% of our total revenues in 2016.

During 2016, we participated in the drilling of 81 horizontal wells (46 operated) and participated in the completion of 90 horizontal wells (53 operated). In our 2016 vertical drilling program, we drilled 4 vertical operated wells and completed 6 operated vertical wells. In 2015, we drilled 102 horizontal wells (53 operated) and completed 91 horizontal wells (45 operated). In our 2015 vertical drilling program, we drilled 16 vertical wells (12 operated) and completed 24 vertical wells (19 operated). At the end of 2016, we operated four horizontal rigs in the Midland Basin and one horizontal rig in the Delaware Basin.

How We Evaluate Our Operations

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

- production volumes;
- revenues on the sale of oil, NGLs and natural gas, including the effect of our commodity derivative contracts on our production;
- operating expenses; and
- capital efficiency

Due to the inherent volatility in commodity prices, we have historically used commodity derivative instruments, such as collars, swaps and puts, to hedge price risk associated with a significant portion of our anticipated production. Our hedging instruments allow us to reduce, but not eliminate, the potential effects of the variability in cash flow from operations due to fluctuations in commodity prices and provide increased certainty of cash flows for our drilling program and debt service requirements. These instruments provide only partial price protection against declines in commodity prices and may partially limit our potential gains from future increases in prices. None of our instruments are used for trading purposes. We do not speculate on commodity prices but rather attempt to hedge a portion of our physical production in order to protect our returns. Our revolving credit facility limits our ability to enter into commodity hedges covering greater than 85% of our reasonably projected production volume.

We will continue to use commodity derivative instruments to hedge our price risk in the future. Our hedging strategy and future hedging transactions will be determined at our discretion and may be different than what we have done on a historical basis. We are not under an obligation to hedge a specific portion of our production. For information regarding the summary of

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open positions, see Note 4 of Notes to Consolidated Financial Statements included in "Part II, Item 8. Financial Statements and Supplementary Data."

2017 Capital Budget

Our board of directors has approved an initial capital budget for drilling, completion, and infrastructure for 2017 of approximately $625 to $700 million which anticipates increasing our operated horizontal rig count from five currently to eight by the end of the year. We will continue to monitor commodity prices, our cash flow and returns to determine adjustments to our capital budget. We intend to allocate our 2017 capital budget approximately as follows:

- $575 to $625 million for drilling and completion activities; approximately 10% of which is non-operated drilling and completion activities; and
- $50 to $75 million for infrastructure and other.

Our 2017 capital budget excludes acquisitions and additions to leasehold and is subject to change depending upon a number of factors, including prevailing and anticipated prices for oil, NGLs and natural gas, results of horizontal drilling and completions, economic and industry conditions at the time of drilling, the availability of sufficient capital resources for drilling prospects, our financial results and the availability of lease extensions and renewals on reasonable terms.

Results of Operations

Year Ended December 31, 2016 Compared to the Year Ended December 31, 2015

Oil, NGLs and Natural Gas 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,			
	2016	2015	Change	% Change
Revenues (in thousands, except percentages):				
Oil sales	$321,588	$263,286	$58,302	22 %
Natural gas sales	13,945	10,517	3,428	33 %
NGL sales	18,324	10,189	8,135	80 %
Total revenues	$353,857	$283,992	$69,865	25 %
Average sales prices:				
Oil (per Bbl) (excluding impact of cash settled derivatives)	$41.28	$45.36	$(4.08)	(9)%
Oil (per Bbl) (after impact of cash settled derivatives)	41.06	61.22	(20.16)	(33)%
Natural gas (per Mcf)	1.94	2.11	(0.17)	(8)%
Natural gas (per Mcf) (after impact of cash settled derivatives)	1.94	2.11	(0.17)	(8)%
NGLs (per Bbl)	10.87	9.75	1.12	11 %
Total (per Boe) (excluding impact of cash settled derivatives)	$33.15	$36.97	$(3.82)	(10)%
Total (per Boe) (after impact of cash settled derivatives)	$32.99	$48.96	$(15.97)	(33)%
Production:				
Oil (MBbls)	7,790	5,805	1,985	34 %
Natural gas (MMcf)	7,188	4,991	2,197	44 %
NGLs (MBbls)	1,685	1,045	640	61 %
Total (MBoe)	10,673	7,682	2,991	39 %
Average daily production volume:				

Total (Boe/d)	29,161	21,047	8,114	39	%

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The following table shows the relationship between our average realized oil price as a percentage of the average NYMEX price and the relationship between our average realized natural gas price as a percentage of the average NYMEX price for the periods indicated. Management uses the realized price to NYMEX margin analysis to analyze trends in our oil and natural gas revenues. The NYMEX WTI futures price is a widely used benchmark in the pricing of domestic and imported oil in the United States. The actual prices realized from the sale of oil differ from the quoted NYMEX WTI price as a result of quality and location differentials. For example, the prices we realize on the oil we produce are affected by the ability to transport crude oil to the Cushing, Oklahoma transport hub and the Gulf Coast refineries. The NYMEX Henry Hub price of natural gas is a widely used benchmark for the pricing of natural gas in the United States. Similar to oil, the actual prices realized from the sale of natural gas differ from the quoted NYMEX Henry Hub price as a result of quality and location differentials. For example, depending on pricing, liquids rich natural gas with a high Btu content may sell at a premium to low Btu content dry natural gas because it yields a greater quantity of NGLs. Location differentials to NYMEX Henry Hub prices result from variances in transportation costs based on the natural gas' proximity to the major consuming markets to which it is ultimately delivered. Also affecting the differential is the processing fee deduction retained by the natural gas processing plant generally in the form of percentage of proceeds.

	Year Ended December 31,	
	2016	2015
Average realized oil price ($/Bbl)	$41.28	$45.36
Average NYMEX ($/Bbl)	43.32	48.80
Differential to NYMEX	(2.04)	(3.44)
Average realized oil price to NYMEX percentage	95%	93%
Average realized natural gas price ($/Mcf)	$1.94	$2.11
Average NYMEX ($/Mcf)	2.46	2.67
Differential to NYMEX	(0.52)	(0.56)
Average realized natural gas price to NYMEX percentage	79%	79%
Average realized NGL price ($/Bbl)	$10.87	$9.75
Average NYMEX oil price ($/Bbl)	43.32	48.80
Average realized NGL price to NYMEX oil price percentage	25%	20%

Our average realized oil price as a percentage of the average NYMEX price was 95% and 93% for the years ended December 31, 2016 and 2015, respectively. All of our oil contracts are impacted by the Midland-Cushing differential, which was negative $0.15 per Bbl for the year ended December 31, 2016 and negative $0.41 per Bbl for the year ended December 31, 2015. As the differential decreased, our realized price per barrel of oil increased. This differential has continued to be lower than historical amounts as new pipeline infrastructure has been put into service and lower than anticipated production growth has occurred, alleviating pipeline capacity constraints that occurred in prior periods.

Oil revenues increased 22% to $321.6 million for the year ended December 31, 2016 from $263.3 million for the year ended December 31, 2015 as a result of an increase in oil production volumes of 1,985 MBbls, or 34%, partially offset by an $4.08 per Bbl decrease, or 9%, in our average realized price for oil.

Natural gas revenues increased 33% and were $13.9 million and $10.5 million for the years ended December 31, 2016 and 2015, respectively. Natural gas production volumes increased by 2,197 MMcf, or 44%, partially offset by an 8% decrease in our average realized price per Mcf.

NGL revenues increased 80% to $18.3 million for the year ended December 31, 2016 from $10.2 million for the year ended December 31, 2015 period as a result of a $1.12 per Bbl increase, or 11%, in our average realized NGL price and an increase in NGL production volumes of 640 MBbls, or 61%.

Our higher production volumes for all products were primarily a result of increased production from our drilling program, along with the full period impact of our acquisitions that closed in 2015.

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

	Year Ended December 31,			
	2016	2015	$ Change	% Change
Operating expenses (in thousands, except percentages):				
Lease operating expenses	$57,778	$53,124	$4,654	9 %
Production and ad valorem taxes	21,615	19,995	1,620	8 %
Depreciation, depletion and amortization	194,360	154,039	40,321	26 %
Asset retirement obligation accretion	472	336	136	40 %
Impairment of unproved properties	4,901	34,269	(29,368)	(86)%
Exploration expense	1,093	2,380	(1,287)	(54)%
General and administrative expenses	36,170	27,317	8,853	32 %
Acquisition costs	6,374	—	6,374	100 %
Total operating expenses before loss on sale of assets	$322,763	$291,460	$31,303	11 %
Expenses per Boe:				
Lease operating expenses (excluding gathering and transportation)	$4.93	$6.46	(1.53)	(24)%
Gathering and transportation	0.48	0.46	0.02	4 %
Production and ad valorem taxes	2.03	2.60	(0.57)	(22)%
Depreciation, depletion and amortization	18.21	20.05	(1.84)	(9)%
Asset retirement obligation accretion	0.04	0.04	—	— %
Impairment	0.46	4.46	(4.00)	(90)%
Exploration expense	0.10	0.31	(0.21)	(68)%
General and administrative - cash component	2.10	2.33	(0.23)	(10)%
General and administrative - recurring stock comp (1)	1.23	1.03	0.20	19 %
General and administrative - IPO stock comp (2)	—	0.19	(0.19)	(100)%
General and administrative - non-recurring stock comp (3)	0.06	—	0.06	NM
Acquisition costs	0.60	—	0.60	100 %
Total operating expenses per Boe	$30.24	$37.93	$(7.69)	(20)%

(1) Represents non-cash compensation expense related to restricted stock awards and performance share awards granted as part of the Company's ongoing compensation and retention program.
(2) IPO stock compensation in 2015 includes compensation expense related to the successful completion of the Company's IPO. These one-time awards vested over time for retention purposes.
(3) The non-recurring 2016 amount is a compensation charge associated with the retirement of an officer of the Company.

Lease Operating Expenses. Lease operating expenses increased 9% to $57.8 million for the year ended December 31, 2016 from $53.1 million for the 2015 period due to a 39% increase in production. On a per Boe basis, lease operating expense, excluding gathering and transportation costs, decreased from $6.46 per Boe in 2015 to $4.93 per Boe in 2016. The decrease was primarily attributable to production growth over a fixed component of costs, increased operating efficiencies and cost reduction efforts in 2016. Gathering and transportation costs, which are included in lease operating expenses, were $5.1 million for the year ended December 31, 2016 and $3.5 million for the 2015 period. On a per Boe basis, our gathering and transportation costs were $0.48 and $0.46 for the years ended December 31, 2016 and 2015 respectively.

Production and Ad Valorem Taxes. Production and ad valorem taxes increased 8% to $21.6 million for the year ended December 31, 2016 from $20.0 million for the 2015 period primarily due to higher production volumes and revenues in the 2016 period, and decreased 22% on a per Boe basis to $2.03 per Boe for the year ended December 31, 2016.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (“DD&A”) expense increased 26% to $194.4 million for the year ended December 31, 2016 from $154.0 million for the 2015 period mainly due to increased production. The DD&A rate decreased 9% to 18.21 per Boe for the year ended December 31, 2016 from 20.05 per Boe for the 2015 period. The decrease in depletion per Boe in 2016 was due to an increase in our reserve volumes over the last year from acquisitions as well as successful drilling activities, somewhat offset by an increase in capitalized costs in proved property over the last year from these same activities.

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Impairments. We incurred $4.9 million and $34.3 million of impairment expense for the years ended December 31, 2016 and 2015, respectively. The impairments recognized in 2016 related to unproved properties with upcoming acreage lease expirations that the Company does not intend to extend or develop. Impairments in 2015 included $19.6 million for proved properties and $14.7 million for unproved properties. The impairments to proved property in 2015 related to properties whose future net revenues were less than the property's carrying value, while the impairment to unproved properties related to acreage pending lease expirations that the Company did not intend to extend or develop. We may incur additional unproved property impairments in the future due to acreage expirations and changes in development plans. We may incur proved property impairments in the future if commodity prices remain low. The possibility and amount of any future impairment is difficult to predict, and will depend, in part, upon future oil and gas prices, estimates of proved reserves and future capital expenditures and production costs.

Exploration Expense. Exploration expense decreased from $2.4 million for the year ended December 31, 2015 to $1.1 million for the 2016 period due to a decrease in expenditures on geological and geophysical activity in 2016.

General and Administrative Expenses. General and administrative expenses increased to $36.2 million for the year ended December 31, 2016, from $27.3 million for the 2015 period primarily due to increases in the number of employees and related expense including equity-based compensation. Equity-based compensation expense, which is recorded in general and administrative expenses, was $13.8 million for the year ended December 31, 2016 and $9.4 million for the 2015 period. On a per Boe basis, recurring general and administrative expenses decreased from $3.36 per Boe to $3.33 per Boe.

Acquisition costs. Acquisition costs in 2016 related to costs associated with the Silver Hill acquisitions.

Other Income and Expenses. The following table summarizes our other income and expenses:

	Year Ended December 31,			
	2016	2015	$ Change	% Change
Other income (expense) (in thousands, except percentages):				
Other income, net	$1,833	$469	$1,364	291 %
Net gain (loss) on derivative instruments	(23,760)	20,906	(44,666)	(214)%
Interest expense	(52,724)	(43,538)	(9,186)	21 %
Total other income (expense)	$(74,651)	$(22,163)	$(52,488)	237 %

Net Gain (Loss) on Derivative Instruments. During the year ended December 31, 2016, we recorded a $23.8 million net loss as compared to a $20.9 million net gain in the 2015 period. The change was a result of expiring contracts on derivative positions over the prior year and the future commodity price outlook as of December 31, 2016, as compared to December 31, 2015.

Interest Expense. During the year ended December 31, 2016, we recorded $52.7 million of interest expense, as compared to $43.5 million in the 2015 period. Interest expense was higher than the prior-year period as a result of a full year of interest expense related to the issuance of additional senior notes in August 2015, and to a lesser extent, due to additional senior notes issued in December 2016.

Income Tax Benefit. During the year ended December 31, 2016, we recorded $18.7 million of income tax benefit, compared to $11.7 million of income tax benefit in the 2015 period. In the third quarter of 2016, the Company recorded a return to provision adjustment which incorporated both a tax provision benefit and a reserve for an uncertain tax position which resulted in a net tax benefit of $2.3 million. In the fourth quarter of 2016, the Company recorded estimated research and development credits, less a reserve for uncertain tax positions, which resulted in a net tax benefit of $1.5 million. These adjustments resulted in an effective rate change year over year.

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

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

	Year Ended December 31, 2015	2014	Change	% Change
Revenues (in thousands, except percentages):				
Oil sales	$263,286	$253,371	$9,915	4 %
Natural gas sales	10,517	10,572	(55)	(1)%
NGL sales	10,189	17,982	(7,793)	(43)%
Total revenues	$283,992	$281,925	$2,067	1 %
Average sales prices:				
Oil (per Bbl) (excluding impact of cash settled derivatives)	$45.36	$83.10	$(37.74)	(45)%
Oil (per Bbl) (after impact of cash settled derivatives)	61.22	85.01	(23.79)	(28)%
Natural gas (per Mcf)	2.11	3.55	(1.44)	(41)%
Natural gas (per Mcf) (after impact of cash settled derivatives)	2.11	3.59	(1.48)	(41)%
NGLs (per Bbl)	9.75	25.04	(15.29)	(61)%
Total (per Boe) (excluding impact of cash settled derivatives)	$36.97	$66.13	$(29.16)	(44)%
Total (per Boe) (after impact of cash settled derivatives)	$48.96	$67.53	$(18.57)	(27)%
Production:				
Oil (MBbls)	5,805	3,049	2,756	90 %
Natural gas (MMcf)	4,991	2,974	2,017	68 %
NGLs (MBbls)	1,045	718	327	46 %
Total (MBoe)	7,682	4,263	3,419	80 %
Average daily production volume:				
Total (Boe/d)	21,047	11,679	9,368	80 %

The following table shows the relationship between our average realized oil price as a percentage of the average NYMEX price and the relationship between our average realized natural gas price as a percentage of the average NYMEX price for the periods indicated. Management uses the realized price to NYMEX margin analysis to analyze trends in our oil and natural gas revenues.

	Year Ended December 31, 2015	2014
Average realized oil price ($/Bbl)	$45.36	$83.10
Average NYMEX ($/Bbl)	48.80	93.00
Differential to NYMEX	(3.44)	(9.90)
Average realized oil price to NYMEX percentage	93 %	89 %
Average realized natural gas price ($/Mcf)	$2.11	$3.55
Average NYMEX ($/Mcf)	2.67	4.26
Differential to NYMEX	(0.56)	(0.71)
Average realized natural gas price to NYMEX percentage	79 %	83 %
Average realized NGL price ($/Bbl)	$9.75	$25.04
Average NYMEX oil price ($/Bbl)	48.80	93.00
Average realized NGL price to NYMEX oil price percentage	20 %	27 %

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Our average realized oil price as a percentage of the average NYMEX price increased to 93% for the year ended December 31, 2015 as compared to 89% in 2014. All of our oil contracts are impacted by the Midland-Cushing differential, which was negative $0.41 per Bbl in 2015, compared to negative $6.90 per Bbl in 2014. As the differential decreased, our realized price per barrel of oil increased. This differential has continued to be at lower historical amounts as new pipeline infrastructure has been put into service, and lower than anticipated production growth has occurred, alleviating pipeline capacity constraints that occurred in 2014.

Oil revenues increased 4% to $263.3 million for the year ended December 31, 2015 from $253.4 million for 2014 as a result of an increase in oil production volumes of 2,756 MBbls substantially offset by a $37.74 per Bbl decrease in our average realized price for oil.

Natural gas revenues decreased 1% to $10.5 million for the year ended December 31, 2015 from $10.6 million for 2014 as a result of an increase in natural gas production volumes of 2,017 MMcf and a $1.44 per Mcf decrease in our average realized natural gas price.

NGL revenues decreased 43% to $10.2 million for the year ended December 31, 2015 from $18.0 million for 2014 as a result of an increase in NGL production volumes of 327 MBbls partially offset by a $15.29 per Bbl decrease in our average realized NGL price.

Our higher production volumes for all products was a result of increased production from our drilling program in 2015 along with acquisitions of producing properties made in 2015.

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

	Year Ended December 31, 2015	Year Ended December 31, 2014	$ Change	% Change
Operating expenses (in thousands, except percentages):				
Lease operating expenses	$53,124	$34,704	$18,420	53 %
Production and ad valorem taxes	19,995	19,758	237	1 %
Depreciation, depletion and amortization	154,039	87,844	66,195	75 %
Asset retirement obligation accretion	336	142	194	137 %
Impairment (1)	34,269	4,344	29,925	689 %
Exploration expense	2,380	3,854	(1,474)	(38)%
General and administrative expenses	27,317	38,357	(11,040)	(29)%
Total operating expenses before loss on sale of assets	$291,460	$189,003	$102,457	54 %
Loss on sale of assets	306	13	293	NM
Total operating expenses after loss on sale of assets	$291,766	$189,016	$102,750	54 %
Expenses per Boe:				
Lease operating expenses (excluding gathering and transportation)	$6.46	$7.49	(1.03)	(14)%
Gathering and transportation	0.46	0.65	(0.19)	(29)%
Production and ad valorem taxes	2.60	4.63	(2.03)	(44)%
Depreciation, depletion and amortization	20.05	20.61	(0.56)	(3)%
Asset retirement obligation accretion	0.04	0.03	0.01	33 %
Impairment (1)	4.46	1.02	3.44	337 %
Exploration expense	0.31	0.90	(0.59)	(66)%
General and administrative - cash component	2.33	4.25	(1.92)	(45)%
General and administrative - (non IPO stock comp)(2)	1.03	0.64	0.39	61 %
General and administrative - (IPO stock comp)(3)	0.19	4.11	(3.92)	(95)%

Total operating expenses per Boe	$37.93	$44.33	$(6.40)	(14)%

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(1) Impairments in 2014 primarily relate to unproved properties where lease terms expired. Impairments in 2015 relate primarily to write downs of the value of proved and unproved properties in Dawson County, where these properties were deemed impaired based upon impairment testing under successful efforts accounting.
(2) Represents compensation expense related to restricted stock awards and performance share awards granted as part of the Company's ongoing compensation and retention program.
(3) IPO stock comp consists of two components. One component represents restricted stock awarded to certain employees as a result of a successful IPO. These one-time awards vest over time for retention purposes. The other component represents non-cash compensation expense associated with incentive units owned by certain members of management. These incentive units determined the stock allocation between management and Natural Gas Partners and had no dilutive impact or cash impact to the Company. See the discussion of incentive units in Note 9-Equity Based Compensation of Notes to Consolidated Financial Statements included in "Part II, Item 8. Financial Statements and Supplementary Data."

Lease Operating Expenses. Lease operating expenses increased 53% to $53.1 million for the year ended December 31, 2015 from $34.7 million for 2014. The increase in our lease operating expense was attributable to the increase in production in 2015. On a per Boe basis, lease operating expense decreased from $7.49 per Boe in 2014 to $6.46 per Boe in 2015. Gathering and transportation costs, which are included in lease operating expenses, were $3.5 million and $2.8 million for the years ended December 31, 2015 and 2014, respectively. On a per Boe basis, our gathering and transportation costs were $0.46 and $0.65 for the years ended December 31, 2015 and 2014, respectively.

Production and Ad Valorem Taxes. Production and ad valorem taxes increased 1% to $20.0 million for the year ended December 31, 2015 from $19.8 million for 2014 primarily as a result of slightly higher wellhead revenues but decreased 44% on a per Boe basis to $2.60 per Boe in 2015.

Depreciation, Depletion and Amortization. DD&A expense increased 75% to $154.0 million for the year ended December 31, 2014 from $87.8 million for 2014 mainly due to increased production and costs related to property acquisitions. The DD&A rate decreased 3% to $20.05 per Boe for the year ended December 31, 2015 from $20.61 per Boe for 2014. The decrease in depletion per Boe in 2015 was due to our reserves volumes in 2015, both from our successful drilling program and through acquisitions, increasing more than additional capitalized costs in proved property incurred from these activities.

Impairment. We incurred $34.3 million of impairment expense on both proved and unproved properties in 2015. The impairment expense for proved properties was $19.6 million and related to properties whose future net revenues were less than the property's carrying value. The impairment expense for unproved properties was $14.7 million and related to acreage pending lease expirations that the Company does not intend to renew, along with certain leasehold interests that may be sold in the future. We may incur additional impairments to our oil and natural gas properties in the future if commodity prices continue to decline. The possibility and amount of any future impairment is difficult to predict, and will depend, in part, upon future oil and gas prices, estimates of proved reserves and future capital expenditures and production costs.

Exploration Expense. Exploration expense decreased to $2.4 million for the year ended December 31, 2015 from $3.9 million for 2014 due to a decrease in geological and geophysical activity in 2015.

General and Administrative Expenses. General and administrative expenses decreased to $27.3 million for the year ended December 31, 2015, from $38.4 million for the 2014 period primarily due to decreases in share based compensation expense. Share-based compensation expense, which was recorded in General and administrative expenses, was $9.4 million for the year ended December 31, 2015 and $20.2 million for the 2014 period. The 2014 period had $14.7 million of non-recurring, non-cash, compensation expense associated with incentive units owned by certain members of management. On a per Boe basis, recurring general and administrative expenses decreased from

$4.89 per Boe to $3.26 per Boe.

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

	Year Ended December 31, 2015	Year Ended December 31, 2014	$ Change	% Change
Other income (expense) (in thousands, except percentages):				
Other income (expense), net	$469	$(44)	$513	NM
Gain (loss) on derivative instruments	20,906	81,470	(60,564)	NM
Interest expense	(43,538)	(14,031)	(29,507)	(210)%
Total other income (expense)	$(22,163)	$67,395	$(89,558)	NM

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Other Income. Other income was $0.5 million for the year ended December 31, 2015 and expense of less than $0.1 million in the 2014 period.

Gain (Loss) on Derivative Instruments. During the year ended December 31, 2015, we recorded a $20.9 million gain as compared to an $81.5 million gain in 2014. The change was a result of the future commodity price outlook as of December 31, 2015 as compared to December 31, 2014 along with additional derivative contracts entered into during 2014 and 2015.

Interest Expense. During the year ended December 31, 2015, we recorded $43.5 million of interest expense as compared to $14.0 million in 2014. The change was primarily the result of expense incurred on our senior notes issued in September 2014 and August 2015. We expect our interest expense to remain higher than the prior-year period as a result of the issuance of additional senior notes in August 2015.

Income Tax Expense. During the year ended December 31, 2015, we recorded $11.7 million of income tax benefit compared to $157.8 million of expense in 2014. The decrease is largely related to a pretax book loss in 2015 compared to pretax book income in 2014, as well as a large deferred tax expense in 2014 related to the our conversion to a subchapter C corporation. We are currently subject to income taxes at a blended statutory rate of 36% of pretax earnings, exclusive of permanent difference. Our predecessor was not subject to federal income taxes and was subject to State of Texas franchise taxes at less than 1% of modified pre-tax earnings. The Company established a $132.0 million provision for deferred income taxes, which was recognized as tax expense from continuing operations in the first quarter of 2014. This $132 million provision, related to our change in tax status, was subsequently adjusted to $95.2 million during the fourth quarter of 2014.

Capital Requirements and Sources of Liquidity

The Company's primary sources of liquidity have been proceeds from equity offerings, borrowings under the revolving credit facility, proceeds from the issuance of senior notes, and cash flows from operations. To date, the Company's primary use of capital has been for the acquisition, development and exploration of oil and natural gas properties. At December 31, 2016, we had no borrowings outstanding under our revolving credit facility and our borrowing base was $950 million with a Company elected commitment amount of $900 million.

During 2016, our capital expenditures totaled $294 million, which included approximately $275 million spent on drilling and completion activities and $19 million spent on infrastructure and other expenditures. In addition, we spent $69 million on acquisitions and additions to leasehold in the Midland Basin. In 2015, our capital expenditures totaled $391 million, which included $354 million on drilling and completion activities, $37 million on infrastructure and other expenditures. In addition, we spent approximately $456 million on acquisitions and additions to leasehold.

We operate a high percentage of our acreage; therefore, the amount and timing of these capital expenditures are largely discretionary. We may elect to defer a portion of planned capital expenditures depending on a variety of factors, including: returns generated by our drilling program, the level of our expenditures in relation to our cash flow, the success of our drilling activities; prevailing and anticipated prices for oil, NGLs and natural gas; the availability of necessary equipment, infrastructure and capital; the receipt and timing of required regulatory permits and approvals; drilling, completion and acquisition costs; and the level of participation by other working interest owners.

Based on current expectations, we believe we have sufficient liquidity through our existing cash balances, cash flow from operations and available borrowings under our revolving credit facility to execute our current capital program excluding any acquisitions we may consummate. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and additional capital expenditures may be required to more fully develop our properties. In the event we make additional 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 borrowings under our revolving credit facility, joint venture partnerships, production payment financings, asset sales, offerings of debt and equity securities or other means. We cannot be assured that needed capital will be available on acceptable terms or at all. If we are unable to obtain funds when needed or on acceptable terms, we may be required to curtail our current drilling program, which could result in a loss of acreage through lease expirations. In addition, we may not be able to complete acquisitions that may be favorable to us or finance the capital expenditures necessary to maintain our production or replace our reserves.

SHEP II Acquisition

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The Company intends to finance the cash portion of the SHEP II acquisition with a combination of cash on hand and the remaining availability under our revolving credit facility.

Working Capital

Our working capital, which we define as current assets minus current liabilities, totaled $668.0 million and $110.1 million at December 31, 2016 and December 31, 2015, respectively. Our collection of receivables has historically been timely, and losses associated with uncollectible receivables have historically not been significant. Our cash balances totaled $690.8 million and $142.7 million at December 31, 2016 and 2015, respectively. Due to the amounts that accrue related to our drilling program, we may incur working capital deficits in the future. We expect that our cash flows from operating activities and availability under our revolving credit facility will be sufficient to fund our working capital needs excluding any acquisitions we may consummate. We expect that our pace of development, production volumes, commodity prices and differentials to NYMEX prices for our oil, NGL and natural gas production will be the largest variables affecting our working capital.

Contractual Obligations

A summary of the Company's contractual obligations as of December 31, 2016 is provided in the following table (in thousands).

	Payments Due by Period For the Year Ended December 31,						
	2017	2018	2019	2020	2021	Thereafter	Total
	(In thousands)						
Revolving credit facility (1)	$—	$—	$—	$—	$—	$—	$—
5.25% Senior Notes (2)						450,000	450,000
6.625% Senior Notes (2)						700,000	700,000
Interest cost (3)	58,508	70,000	70,000	70,000	70,000	129,063	467,571
Drilling rig commitments (4)	6,776						6,776
Office and equipment leases	1,094	1,357	1,070	160	69	—	3,750
Asset retirement obligations (5)						10,659	10,659
Total	$66,378	$71,357	$71,070	$70,160	$70,069	$1,289,722	$1,638,756

(1) This table does not include future commitment fees, amortization of deferred financing costs, interest expense or other fees on our revolving credit facility because obligations thereunder are floating rate instruments and we cannot determine with accuracy the timing of future loan advances, repayments or future interest rates to be charged.
(2) Includes principal only.
(3) Related to fixed rate debt only, which is the 6.625% Senior Notes and the 5.25% Senior Notes.
(4) The values in the table represent the gross amounts that the Company is committed to pay. Drilling rigs operating on the Silver Hill acquisition acreage are contracted on a well to well basis.
(5) 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.

Off-Balance Sheet Arrangements

As of December 31, 2016, we did not have any off-balance sheet arrangements that have or are reasonably likely to have a current or future effect on our financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources and would be considered material to investors.

Cash Flows

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

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	Year Ended December 31,		
	2016	2015	2014 (1)
	(In thousands)		
Net cash provided by operating activities	$166,213	$218,805	$223,157
Net cash used in investing activities	(1,029,423)	(874,939)	(816,925)
Net cash (used in) provided by financing activities	$1,411,245	$742,583	$636,826

(1) Represents our predecessor's historical financial data for the first 22 days of 2014 plus RSP, Inc.'s historical financial data for the remainder of the year.

Net cash provided by operating activities was approximately $166.2 million, $218.8 million, and $223.2 million for the years ended December 31, 2016, 2015, and 2014 respectively. The decrease in net cash provided by operating activities for the year ended December 31, 2016, as compared to the 2015 period, was primarily due to a reduction in amounts received from our settled derivative contracts in the 2016 period. Cash flows from operations decreased in 2015 as compared to 2014 mainly due to reductions in working capital accounts.

Net cash used in investing activities was approximately $1.0 billion , $874.9 million, and $816.9 million for the years ended December 31, 2016, 2015, and 2014, respectively. The increase in cash used in investing activities was due to acquisitions in the 2016 period. The increase in the amount of cash used in investing activities in the 2015 period compared to the 2014 period was due to additional acquisition activity.

Net cash provided by financing activities was approximately $1.4 billion, $742.6 million, and $636.8 million for the years ended December 31, 2016, 2015, and 2014, respectively. The 2016 period includes capital received in a follow-on stock offering as well as an issuance of senior notes. For the 2015 period, the increased cash provided by financing activities was primarily the result of cash proceeds received in connection with follow-on stock offerings, along with the issuance of $200.0 million of additional senior notes in 2015.

Our Revolving Credit Facility

Our credit agreement has a borrowing base of $950 million, an elected commitment amount of $900 million, lenders' maximum facility commitments of $2.5 billion, and a maturity date of December 19, 2021. The credit agreement permits RSP LLC to make payments to the Company to enable it to pay principal, premium (if any) and interest on our existing notes, provided no default has occurred, and to allow RSP LLC to guarantee the existing notes.

The amount available to be borrowed under our revolving credit facility is subject to a borrowing base that is redetermined semiannually each May and November and depends on the volumes of our proved oil and natural gas reserves, estimated cash flows from these reserves and our commodity hedge positions. Provided that the SHEP II Acquisition closes before May 1, 2017, our next borrowing base redetermination is scheduled for November 2017. As of December 31, 2016, we had no borrowings and $0.6 million of letters of credit outstanding under our revolving credit facility and $899.4 million of borrowing capacity. In the event of any future offerings of senior unsecured notes issued or guaranteed by RSP LLC, the borrowing base under our revolving credit facility will be automatically reduced by an amount equal to 0.25 multiplied by the aggregate principal amount of notes issued or guaranteed on the date of such issuance.
Our revolving credit facility is secured by liens on substantially all of our properties and guarantees from our subsidiaries other than any subsidiary that we have designated as an unrestricted subsidiary.

Our revolving credit facility contains restrictive covenants that may limit our ability to, among other things:

- incur additional indebtedness;
- make loans to others;

- make investments;
- enter into mergers;
- make or declare dividends;
- enter into commodity hedges exceeding a specified percentage or our expected production;
- enter into interest rate hedges exceeding a specified percentage of our outstanding indebtedness;
- incur liens;
- sell assets; and
- engage in certain other transactions without the prior consent of the lenders.

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Our revolving credit facility also requires us to maintain the following two financial ratios:

- a working capital ratio, which is the ratio of consolidated current assets (includes unused commitments under our revolving credit facility and excludes restricted cash and derivative assets) to consolidated current liabilities (excluding the current portion of long term debt under the credit facility and derivative liabilities), of not less than 1.0 to 1.0;
- a leverage ratio, which is the ratio of the sum of all of the Company's debt to the consolidated EBITDAX (as defined in our revolving credit facility) for the four fiscal quarters then ended, of not greater than 4.25 to 1.0. For the fiscal quarters ending December 31, 2016, March 31, 2017 and June 30, 2017, the consolidated EBITDAX shall be deemed to equal (A) consolidated EBITDAX for the one fiscal quarter period ending December 31, 2016 multiplied by 4, (B) consolidated EBITDAX for the two fiscal quarter period ending March 31, 2017 multiplied by 2 and (C) consolidated EBITDAX for the three fiscal quarter period ending June 30, 2017 multiplied by 4/3, respectively.

We were in compliance with such covenants and ratios as of December 31, 2016.

Principal amounts borrowed are payable on the maturity date, and interest is payable quarterly for base rate loans and at the end of the applicable interest period for Eurodollar loans. The Company has a choice of borrowing at a Eurodollar rate or at the adjusted base rate. Eurodollar loans bear interest at a rate per annum equal to an adjusted LIBOR rate (equal to the quotient of: (i) the LIBOR Rate; divided by (ii) a percentage equal to 100% minus the maximum rate on such date at which the Administrative Agent is required to maintain reserves on “Eurocurrency Liabilities” as defined in and pursuant to Regulation D of the Board of Governors of the Federal Reserve System) plus an applicable margin ranging from 200 to 300 basis points, depending on the percentage of its borrowing base utilized. Alternate base rate loans bear interest at a rate per annum equal to the greatest of: (i) the agent bank’s referenced rate; (ii) the federal funds effective rate plus 50 basis points; and (iii) the adjusted LIBOR rate plus 100 basis points, plus an applicable margin ranging from 100 to 200 basis points, depending on the percentage of our borrowing base utilized, plus a commitment fee ranging from 37.5 basis points to 50 basis points charged on the undrawn commitment amount. At December 31, 2016, the prime borrowing rate of interest under the Company's revolving credit facility was 3.5%.

Critical Accounting Policies and Estimates

The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our financial statements.

Successful Efforts Method of Accounting for Oil and Natural Gas Activities

Our oil and natural gas producing activities are accounted for using the successful efforts method of accounting. Under the successful efforts method we capitalize lease acquisition costs, all development costs and successful exploration costs.

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 seismic expenditures and 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.

Proved oil and natural gas properties. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering, and storing oil, gas and NGLs are capitalized. All costs incurred to drill and equip successful

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exploratory wells, development wells, development-type stratigraphic test wells and service wells, including unsuccessful development wells, are capitalized. Capitalized acquisition costs attributable to proved oil and natural gas properties and leasehold costs are depleted on a field level, based on proved reserves, using the unit-of-production method. Capitalized exploration well costs and development costs, including AROs, are depleted on a field level, based on proved developed reserves.

Impairment

The capitalized costs of proved oil and natural gas properties are reviewed on a field level basis for impairment whenever events or changes in circumstances indicate that a decline in the recoverability of their carrying value may have occurred. This review is completed at least annually. We estimate the expected future cash flows of our oil and natural gas properties and compare these future cash flows to the carrying amount of the oil and natural gas properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we adjust the carrying amount of the oil and natural gas properties to fair value. We estimate fair value by discounting the projected future cash flows at an appropriate risk-adjusted discount rate. The calculation of expected future net cash flows in impairment evaluations are mainly based on estimates of future oil and natural gas prices, proved reserves and risk-adjusted probable reserves quantities, and estimates of future production and capital costs associated with our proved and risk-adjusted reserves. The Company's estimates for future oil and natural gas prices used in the impairment evaluations are based on observable prices for the next three years, and then held constant for the remaining lives of the properties. It is reasonably possible that oil and natural gas prices used in future impairment evaluations may decline, which would result in the need to further impair the carrying value of the Company's properties. For purposes of our impairment analysis as of December 31, 2016, for 2017, 2018, 2019 and thereafter we used (i) average oil prices of $56.59, $56.10, $56.05 and $56.09 per Bbl, respectively, (ii) average NGL prices of $13.58, $13.46, $13.45 and $13.46 per Bbl, respectively, and (iii) average natural gas prices of $3.14, $2.87, $2.88 and $2.94 per MMBtu, respectively. Oil, NGLs and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically the commodities markets have been volatile, and these markets will likely continue to be volatile in the future. For example, during the period from January 1, 2014 through December 16, 2016, oil prices fluctuated from a high of $107.62 per Bbl on June 23, 2014 to $26.21 per Bbl on February 11, 2016, and natural gas prices fluctuated from a high of $7.92 per MMBtu on March 4, 2014 to a low of $1.49 per MMBtu on March 4, 2016. We are unable to predict the direction of future commodity prices. If the prices used to assess our oil and natural gas properties for impairment were 15% lower than the prices we used for such analysis, holding all other variables constant, we would not have expected to record any material impairment to our proved oil and natural properties.

Unproved leasehold costs are assessed at least annually, or more frequently when industry conditions dictate an impairment may be possible, to determine whether they have been impaired. Individually significant properties are assessed for impairment on a property-by-property basis, while individually insignificant unproved leasehold costs may be assessed in the aggregate. If unproved leasehold costs are found to be impaired, an impairment allowance is provided and a loss is recognized in the consolidated statements of operations. Please see the table of expiring acreage in "Part I, Item 2. Properties" in this report. To the extent that the Company has substantial amounts of expiring acreage in future periods, and may not be able to successfully develop this acreage due to market or liquidity concerns, then impairment expense may be material in those future periods. The recognition of impairment expense in these future periods may be difficult to predict and require substantial judgment.

Valuation of Business Combinations

In connection with a business combination, the acquiring company must record assets acquired and liabilities assumed based on fair values as of the acquisition date. Deferred taxes must be recorded for any differences between the assigned values and tax bases of assets and liabilities. Any excess of purchase price over amounts assigned to assets and liabilities is recorded as goodwill. The amount of goodwill recorded in any particular business combination can vary significantly depending upon the value attributed to assets acquired and liabilities assumed.

In estimating the fair values of assets acquired and liabilities assumed, we make various assumptions. The most significant assumptions relates to the estimated fair values assigned to proved and unproved oil and natural gas properties and integrated assets. To estimate the fair values of these properties, we utilize estimates of oil and natural gas reserves. We make future price assumptions to apply to the estimated reserves quantities acquired and estimate future operating and development costs to arrive at estimates of future net cash flows. For estimated proved reserves, the future net cash flows were discounted using a market-based weighted average cost of capital rates determined appropriate at the time of the acquisition. The market-based weighted average cost of capital rates are subject to additional project-specific risking factors. To estimate the fair value of unproved, we apply risk-weighting factors of the future net cash flows of unproved reserves, or we may evaluate acreage values through recent market transactions in the area.

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Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in a higher depletion expense, which results in lower net earnings. Fair values are based on estimates of future commodity prices, reserves quantities, operating expenses and development costs. This increases the likelihood of impairment if future commodity prices or reserves quantities are lower than those originally used to determine fair value or if future operating expenses or development costs are higher than those originally used to determine fair value.

Income Taxes

We became a taxable entity as a result of the contribution of our predecessor, which were limited liability companies, to a corporation in connection with the IPO. Deferred taxes are determined based on the estimated future tax effects of differences between the financial statement and tax basis of assets and liabilities, given the provisions of enacted tax laws. Tax positions are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than fifty percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information.

Recently Issued Accounting Pronouncements

The effects of recently issued accounting pronouncements are discussed in Note 2 of Notes to Consolidated Financial Statements included in "Part II, Item 8. Financial Statements and Supplementary Data."

ITEM 7A. QUALITATIVE AND QUANTITATIVE 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 revenues are subject to market risk and are dependent on the pricing we receive for our oil, NGLs and natural gas production. Pricing for oil, NGLs and natural gas has been volatile and unpredictable for several years, and this volatility is expected to continue in the future. Our realized prices are primarily driven by the prevailing prices for oil and the prevailing spot prices for NGLs and natural gas. We use derivative contracts to reduce our exposure to the changes in the prices of these commodities. Pursuant to our risk management policy, we engage in these activities as a hedging mechanism against price volatility associated with projected production levels. We do not use these instruments to engage in trading activities, and we do not speculate on commodity prices.

The fair value of our derivative contracts as of December 31, 2016 was a net liability of $17.0 million. For information regarding the summary of open positions and terms of these hedges, see Note 4 of Notes to Consolidated Financial Statements.

Counterparty and Customer Credit Risk

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

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

Interest Rate Risk

At December 31, 2016, we had no borrowings outstanding that are subject to interest rate risk. Assuming no change in the amount outstanding, the impact on interest expense of a 1.0% increase or decrease in the assumed weighted average interest rate would not be material. We currently do not engage in any interest rate hedging activity.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

The information required by this Item appears beginning on page 67 of this Report and is incorporated herein by reference.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a-15(b) of the Securities Exchange Act of 1934 (the “Exchange Act”), we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of December 31, 2016. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2016 at the reasonable assurance level.

Attestation Report of the Registered Public Accounting Firm

Grant Thornton LLP, our independent registered public accounting firm, attested to, and report on, our internal control over financial reporting. Grant Thornton's attestation report is referenced on page 69 under the caption "Report of Independent Registered Public Accounting Firm" and is incorporated herein by reference.

Changes in Internal Control over Financial Reporting

There were no changes in our system of internal control over financial reporting (as defined in Rule 13a-15(f) and Rule 15d-15(f) under the Exchange Act) that occurred during the three months ended December 31, 2016 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

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The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company's internal control over financial reporting is a process designed by or under the supervision of the Company's principal executive officer and principal financial officer and effected by the Company's board of directors, management and other personnel to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company's financial statements for external purposes in accordance with generally accepted accounting principles.

The Company's management, with the participation of its principal executive officer and principal financial officer assessed the effectiveness, as of December 31, 2016, of the Company's internal control over financial reporting based on the criteria for effective internal control over financial reporting established in "Internal Control - Integrated Framework (2013)," issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on the assessment, management determined that the Company maintained effective internal control over financial reporting at a reasonable assurance level as of December 31, 2016, based on those criteria.

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required under Item 10 will be set forth in our definitive proxy statement to be filed in connection with our annual stockholders’ meeting to be held in May 2017 and is incorporated herein by reference.

ITEM 11. EXECUTIVE COMPENSATION

The information required under Item 11 will be set forth in our definitive proxy statement to be filed in connection with our annual stockholders’ meeting to be held in May 2017 and is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information required under Item 12 will be set forth in our definitive proxy statement to be filed in connection with our annual stockholders’ meeting to be held in May 2017 and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required under Item 13 will be set forth in our definitive proxy statement to be filed in connection with our annual stockholders’ meeting to be held in May 2017 and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required under Item 14 will be set forth in our definitive proxy statement to be filed in connection with our annual stockholders' meeting to be held in May 2017 and is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

a. The following documents are filed as a part of this Report or incorporated herein by reference:

(1) Financial Statements:

See “Part II, Item 8. Financial Statements and Supplementary Data.”

(2) Financial Statement Schedules:

None.

(3) Exhibits:

The following documents are included as exhibits to this Report:
EXHIBIT INDEX
Exhibit No. Description

3.1	Amended and Restated Certificate of Incorporation of RSP Permian, Inc. (incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on January 29, 2014).
3.2	Amended and Restated Bylaws of RSP Permian, Inc. (incorporated by reference to Exhibit 3.1 of the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the Commission on December 21, 2016).
4.1	Specimen Common Stock Certificate (incorporated by reference to Exhibit 4.1 of the Company's Registration Statement on Form S-1/A (File No. 333-192268) filed with the Commission on January 13, 2014).

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4.2	Registration Rights Agreement, dated as of January 23, 2014, among the Company, RSP Permian Holdco, L.L.C., Ted Collins, Jr., Wallace Family Partnership, LP, ACTOIL, LLC, Rising Star Energy Development Co., L.L.C. and Pecos Energy Partners, L.P. (incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on January 29, 2014).
4.3	Stockholders' Agreement, dated as of January 23, 2014, among the Company, RSP Permian Holdco, L.L.C., Ted Collins, Jr., Wallace Family Partnership, LP, Rising Star Energy Development Co., L.L.C. and Pecos Energy Partners, L.P. (incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on January 29, 2014).
4.4	Indenture, dated as of September 26, 2014, by and among the Company, RSP Permian, L.L.C. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on October 2, 2014).
4.5	Form of Senior Note due 2022 (incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on October 2, 2014).
4.6	Registration Rights Agreement, dated as of August 10, 2015, by and among the Company, RSP Permian, L.L.C. and Goldman, Sachs, & Co. (incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on August 12, 2015).
4.7(a)	Registration Rights Agreement, dated as of November 28, 2016, by and between the Company and Silver Hill Energy Partners Holdings, LLC.
4.8(a)	Stockholder's Agreement, dated as of November 28, 2016, by and between the Company and Kayne Anderson Capital Advisors, LP.
4.9	Indenture, dated as of December 27, 2016, by and among the Company, RSP Permian, L.L.C., Silver Hill Energy Partners, LLC and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on December 27, 2016).
4.10	Form of Senior Note due 2025 (incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on December 27, 2016).
4.11	Registration Rights Agreement, dated as of December 27, 2016, by and among the Company, RSP Permian, L.L.C., Silver Hill Energy Partners, LLC, and Barclays Capital Inc. and RBC Capital Markets, LLC, as representatives of the several initial purchasers (incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on December 27, 2016).
10.1	Amended and Restated Credit Agreement, dated September 10, 2013, by and among RSP Permian, L.L.C., as borrower, Comerica Bank, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company's Registration Statement on Form S-1 (File No. 333-192268) filed with the Commission on November 12, 2013).
10.2	First Amendment to Amended and Restated Credit Agreement, dated June 9, 2014, by and among RSP Permian, L.L.C., as borrower, Comerica Bank, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on June 9, 2014).
10.3	Second Amendment to Amended and Restated Credit Agreement, dated August 29, 2014, by and among RSP Permian, L.L.C., as borrower, Comerica Bank, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on September 4, 2014).
10.4	Third Amendment to Amended and Restated Credit Agreement, dated September 12, 2014, by and among RSP Permian, L.L.C., as borrower, Comerica Bank, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on September 18, 2014).
10.5	Fourth Amendment to Amended and Restated Credit Agreement, dated August 24, 2015, by and among RSP Permian, L.L.C., as borrower, Comerica Bank, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No.

	001-36264) filed with the Commission on August 25, 2015).
10.6(c)	2014 Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on January 22, 2014).
10.7(c)	Form of Restricted Stock Grant and Award Agreement (Performance Vesting) (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on April 16, 2014).
10.8(c)	Form of Restricted Stock Grant and Award Agreement (incorporated by reference to Exhibit 10.3 of the Company's Quarterly Report on Form 10-Q (File No. 001-36264) filed with the Commission on May 15, 2014).
10.9(c)	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.4 to the Company's Registration Statement on Form S-1/A (File No. 333-192268) filed with the Commission on January 2, 2014).
10.10(c)	Executive Change in Control and Severance Benefit Plan of RSP Permian, Inc. (incorporated by reference to Exhibit 10.6 to the Company's Registration Statement on Form S-1/A (File No. 333-196388) filed with the Commission on July 25, 2014).
10.11	Purchase and Sale Agreement, dated July 22, 2014, by and among Adventure Exploration Partners II, LLC, Alpine Oil Company, JM Cox Resources, LP and D.R.E. Interests, LLC, as sellers, and RSP Permian, L.L.C., as purchaser (incorporated by reference to Exhibit 2.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on July 25, 2014).
10.12	Purchase and Sale Agreement, dated November 17, 2015, by and between Wolfberry Partners Resources LLC, as seller, and RSP Permian, L.L.C., as purchaser (incorporated by reference to Exhibit 2.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on November 23, 2015).
10.13	Surface Use and Settlement Agreement, dated November 17, 2015, by and between Collins & Wallace Holdings, LLC and RSP Permian, L.L.C. (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on November 23, 2015).
10.14*	Membership Interest Purchase and Sale Agreement, dated as of October 13, 2016, by and among Silver Hill Energy Partners Holdings, LLC, Silver Hill Energy Partners, LLC, RSP Permian, L.L.C. and the Company (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on October 13, 2016).
10.15*	Membership Interest Purchase and Sale Agreement, dated as of October 13, 2016, by and among Silver Hill Energy Partners II, LLC, Silver Hill E&P II, LLC, RSP Permian, L.L.C. and the Company (incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on October 13, 2016).

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10.16	Purchase Agreement dated as of December 12, 2016, by and among the Company, the Guarantors and Barclays Capital Inc. and RBC Capital Markets, LLC, as representatives of the several initial purchasers (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on December 13, 2016).
10.17	Credit Agreement, dated as of December 19, 2016, among the Company, RSP Permian, L.L.C., JPMorgan Chase Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on December 21, 2016).
12.1	Computation of Ratio of Earnings to Fixed Charges.
21.1(a)	Subsidiaries of RSP Permian, Inc.
23.1(a)	Consent of Grant Thornton LLP.
23.2(a)	Consent of Netherland, Sewell & Associates, Inc.
31.1(a)	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, Rule 13a-14(a)/15d-14(a), by Chief Executive Officer.
31.2(a)	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, Rule 13a-14(a)/15d-14(a), by Chief Financial Officer.
32.1(b)	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Chief Executive Officer.
32.2(b)	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Chief Financial Officer.
99.1(a)	Netherland, Sewell & Associates, Inc. Summary of Reserves at December 31, 2016 (RSP Permian, Inc.).
99.2(a)	Netherland, Sewell & Associates, Inc. Summary of Reserves at December 31, 2016 (Silver Hill II Acquisition Interest).
101.INS(a)	XBRL Instance Document.
101.SCH(a)	XBRL Taxonomy Extension Schema Document.
101.CAL(a)	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF(a)	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB(a)	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE(a)	XBRL Taxonomy Extension Presentation Linkbase Document.

(a) Filed herewith.
(b) Furnished herewith. Pursuant to SEC Release No. 33-8212, this certification will be treated as "accompanying" this report and not "filed" as part of such report for purposes of Section 18 of the Exchange Act or otherwise subject to the liability of Section 18 of the Exchange Act, and this certification will not be deemed to be incorporated by reference into any filing under the Securities Act of 1933, except to the extent that the registrant specifically incorporates it by reference.
(c) Management contract or compensatory plan or arrangement.
* Schedules have been omitted pursuant to Item 601(b)(2) of Regulation S-K. The Company undertakes to furnish supplemental copies of any of the omitted schedules upon request by the U.S. Securities and Exchange Commission.

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ITEM 16. FORM 10-K SUMMARY

None

SIGNATURES

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

RSP PERMIAN, INC.	
By:	/s/ Steven Gray Steven Gray Chief Executive Officer and Director
Date:	February 27, 2017

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

Signature	Title	Date
/s/ Steven Gray Steven Gray	Chief Executive Officer and Director (Principal Executive Officer)	February 27, 2017
/s/ Scott McNeill Scott McNeill	Chief Financial Officer and Director (Principal Financial Officer)	February 27, 2017
/s/ Barry S. Turcotte Barry S. Turcotte	Chief Accounting Officer (Principal Accounting Officer)	February 27, 2017
/s/ Michael Grimm Michael Grimm	Chairman of the Board	February 27, 2017
/s/ Joseph B. Armes Joseph B. Armes	Director	February 27, 2017
/s/ Ted Collins, Jr. Ted Collins, Jr.	Director	February 27, 2017
/s/ Kenneth Huseman Kenneth Huseman	Director	February 27, 2017
/s/ Matthew S. Ramsey Matthew S. Ramsey	Director	February 27, 2017
/s/ Michael W. Wallace Michael W. Wallace	Director	February 27, 2017

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INDEX TO CONSOLIDATED FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
RSP Permian, Inc.

We have audited the internal control over financial reporting of RSP Permian, Inc. (a Delaware corporation) (the "Company") as of December 31, 2016, based on criteria established in the 2013 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

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.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2016, based on criteria established in the 2013 Internal Control-Integrated Framework issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Company as of and for the year ended December 31, 2016, and our report dated February 27, 2017 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2017

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Shareholders
RSP Permian, Inc.

We have audited the accompanying consolidated balance sheets of RSP Permian, Inc. (a Delaware corporation) (the “Company”) as of December 31, 2016 and 2015, and the related consolidated statements of operations, changes in stockholders’/members’ equity, and cash flows for each of the three years in the period ended December 31, 2016. These financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of RSP Permian, Inc. as of December 31, 2016 and 2015, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2016 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 to the consolidated financial statements, the Company adopted new accounting guidance in 2016 and 2015, related to the presentation of debt issuance costs.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company’s internal control over financial reporting as of December 31, 2016, based on criteria established in the 2013 Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 27, 2017 expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP

Dallas, Texas
February 27, 2017

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PART IV
RSP PERMIAN, INC.
CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)

	December 31, 2016	December 31, 2015
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$690,776	$142,741
Accounts receivable	73,671	36,323
Derivative instruments	11,815	8,452
Other assets	—	24
Total current assets	776,262	187,540
PROPERTY, PLANT AND EQUIPMENT		
Oil and natural gas properties, successful efforts method	4,645,781	3,076,051
Accumulated depletion	(554,419)	(357,524)
Total oil and natural gas properties, net	4,091,362	2,718,527
Other property and equipment, net	38,273	40,103
Total property, plant and equipment	4,129,635	2,758,630
OTHER LONG-TERM ASSETS		
Restricted cash	152	152
Other long-term assets	90,378	21,111
Total other long-term assets	90,530	21,263
TOTAL ASSETS	$4,996,427	$2,967,433
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	$14,074	$15,569
Accounts payable, related party	—	6,459
Accrued expenses	53,192	39,231
Interest payable	12,142	12,149
Derivative instruments	28,861	3,994
Total current liabilities	108,269	77,402
LONG-TERM LIABILITIES		
Other long term liabilities	15,916	7,063
Long-term debt	1,132,275	686,512
Deferred taxes	323,239	337,872
Total long-term liabilities	1,471,430	1,031,447
Total liabilities	1,579,699	1,108,849
STOCKHOLDERS' EQUITY		
Common stock, $.01 par value; 300,000,000 shares authorized, 141,923,591 shares issued and outstanding at December 31, 2016; 100,807,286 shares issued and outstanding at December 31, 2015	1,419	1,008
Additional paid-in capital	3,455,916	1,873,332
Accumulated deficit	(40,607)	(15,756)
Total stockholders' equity	3,416,728	1,858,584
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$4,996,427	$2,967,433

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

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RSP PERMIAN, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share data)

	Year Ended December 31,		
	2016	2015	2014
REVENUES			
Oil sales	$321,588	$263,286	$253,371
Natural gas sales	13,945	10,517	10,572
NGL sales	18,324	10,189	17,982
Total revenues	353,857	283,992	281,925
OPERATING EXPENSES			
Lease operating expenses	$57,778	$53,124	$34,704
Production and ad valorem taxes	21,615	19,995	19,758
Depreciation, depletion and amortization	194,360	154,039	87,844
Asset retirement obligation accretion	472	336	142
Impairments	4,901	34,269	4,344
Exploration expenses	1,093	2,380	3,854
General and administrative expenses	36,170	27,317	38,357
Acquisition costs	6,374	—	—
Total operating expenses	322,763	291,460	189,003
Loss on sale of assets	—	306	13
OPERATING INCOME (EXPENSE)	31,094	(7,774)	92,909
OTHER INCOME (EXPENSE)			
Other income, net	$1,833	$469	$(44)
Net gain (loss) on derivative instruments	(23,760)	20,906	81,470
Interest expense	(52,724)	(43,538)	(14,031)
Total other income (expense)	(74,651)	(22,163)	67,395
INCOME (LOSS) BEFORE TAXES	(43,557)	(29,937)	160,304
INCOME TAX BENEFIT (EXPENSE)	18,706	11,683	(157,806)
NET INCOME (LOSS)	$(24,851)	$(18,254)	$2,498
Income (loss) per common share:			
Basic	$(0.23)	$(0.21)	$0.03
Diluted	$(0.23)	$(0.21)	$0.03
Weighted average shares outstanding:			
Basic	107,324	86,770	71,898
Diluted	107,324	86,770	71,898

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

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RSP PERMIAN, INC.
CONSOLIDATED STATEMENTS OF CHANGES IN STOCKHOLDERS'/MEMBERS' EQUITY

	Members' Equity	Issued Shares of Common Stock	Common Stock	Additional Paid-in Capital	Retained Earnings (Accumulated Deficit)	Total Stockholders' Equity/ Members' Equity
	(In thousands)					
BALANCE AT DECEMBER 31, 2013	$386,881	—	$—	$—	$ —	$386,881
Distribution of net assets to predecessor owner, including cash of $1,663	(21,147)	—	—	14,168	—	(6,979)
The corporate reorganization	(365,734)	—	—	365,734	—	—
RSP Permian Holdco, L.L.C.'s contributions of interests in RSP Permian, L.L.C. in exchange for RSP Permian, Inc.'s common stock	—	63,275	633	(633)	—	—
Ted Collins, Jr., Wallace Family Partnership, LP, Collins & Wallace Holdings, LLC, Pecos Energy Partners, L.P. and ACTOIL LLC's contributions in exchange for RSP Permian, Inc.'s common stock	—	—	—	642,436	—	642,436
Shares of common stock issued in public offerings, net of offering costs	—	14,017	140	280,563	—	280,703
Equity-based compensation	—	612	6	20,226	—	20,232
Net income	—	—	—	—	2,498	2,498
BALANCE AT DECEMBER 31, 2014	—	77,904	779	1,322,494	2,498	1,325,771
Shares of common stock issued in public offerings, net of offering costs	—	22,540	226	543,298	—	543,524
Repurchase and retirement of common stock	—	(69)	(1)	(1,840)	—	(1,841)
Equity-based compensation	—	432	4	9,380	—	9,384
Net loss	—	—	—	—	(18,254)	(18,254)
BALANCE AT DECEMBER 31, 2015	$—	100,807	$1,008	$1,873,332	$ (15,756)	$1,858,584

Shares of common stock issued in public offerings, net of offering costs	—	25,300	253	975,722	—	975,975
Shares of common stock issued for acquisition	—	14,980	150	595,769	—	595,919
Repurchase and retirement of common stock	—	(98)	(1)	(2,661)	—	(2,662)
Equity-based compensation	—	935	9	13,754	—	13,763
Net loss	—	—	—	—	(24,851)	(24,851)
BALANCE AT DECEMBER 31, 2016	$—	141,924	$ 1,419	$ 3,455,916	$ (40,607)	$ 3,416,728

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

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RSP PERMIAN, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year Ended December 31,		
	2016	2015	2014
	(In thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income (loss)	$(24,851)	$(18,254)	$2,498
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	194,360	154,039	87,844
Asset retirement obligation accretion	472	336	142
Impairment of unproved properties	4,901	34,269	4,344
Equity-based compensation	13,763	9,384	20,232
Amortization of loan fees	2,675	2,219	1,202
Deferred income taxes	(14,633)	(17,179)	153,468
Other	(570)	(8)	98
Loss on sale of assets	—	306	13
Net loss (gain) on derivative instruments	23,760	(20,906)	(81,470)
Net cash receipts from (payments for) settled derivatives	7,704	89,533	(102)
Changes in operating assets and liabilities:			
Accounts receivable	(45,909)	6,698	(4,383)
Other assets	3,180	(13,570)	14,952
Accounts payable and accounts payable to related parties	(4,096)	(13,700)	17,180
Accrued expenses	5,464	2,717	(1,793)
Interest payable	(7)	2,921	8,932
Net cash provided by operating activities	$166,213	$218,805	$223,157
CASH FLOWS FROM INVESTING ACTIVITIES			
Development of oil and natural gas properties	(286,901)	(401,191)	(449,681)
Acquisitions of oil and natural gas properties	(673,946)	(454,552)	(361,146)
Acquisition deposit held in escrow	(64,109)	—	—
Additions to other property and equipment	(2,123)	(17,126)	(5,475)
Investment in unconsolidated subsidiary	(2,344)	(2,704)	(625)
Proceeds from sale of assets	—	634	2
Net cash used in investing activities	$(1,029,423)	$(874,939)	$(816,925)
CASH FLOWS FROM FINANCING ACTIVITIES			
Issuance of common stock	975,975	543,524	280,703
Distributions	—	—	(1,663)
Payment of deferred loan costs	(12,068)	2,400	(14,059)
Borrowings under long-term debt	253,826	65,000	440,512
Payments on long-term debt	(253,826)	(65,000)	(568,667)
Issuance of senior unsecured notes	450,000	198,500	500,000
Repurchase and retirement of common stock	(2,662)	(1,841)	—
Net cash provided by financing activities	$1,411,245	$742,583	$636,826
NET CHANGE IN CASH	$548,035	$86,449	$43,058
CASH AT BEGINNING OF PERIOD	$142,741	$56,292	$13,234
CASH AT END OF PERIOD	$690,776	$142,741	$56,292
SUPPLEMENTAL CASH FLOW INFORMATION			
Cash paid for interest	$50,010	$42,960	$3,897

Cash paid for taxes	$2,000	$3,450	$3,800
NON-CASH ACTIVITIES			
Asset retirement obligation acquired	$1,056	902	2,147
Change in accrued capital expenditures	$8,496	$(21,463)	$41,573
Common stock issued for oil and gas properties	$595,919	$—	$677,402
Deferred tax liabilities recorded for oil and gas property acquisitions	$—	$—	$199,389
Elimination of NPI payable	$—	$—	$36,931

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

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NOTE 1—NATURE OF OPERATIONS AND BASIS OF PRESENTATION

Organization and Description of the Business

RSP Permian, Inc. ("RSP Inc." or the "Company") was formed on September 30, 2013, pursuant to the laws of the state of Delaware to be a holding company for RSP Permian, L.L.C., a Delaware limited liability company ("RSP LLC"). RSP LLC was formed on October 18, 2010, by its management team and affiliates of Natural Gas Partners, a family of energy-focused private equity investment funds ("NGP"). The Company is engaged in the acquisition, exploration, development and production of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin of West Texas. The Company priced its initial public offering ("IPO") and began trading on the New York Stock Exchange under the ticker RSPP in January 2014.

Basis of Presentation

These consolidated financial statements have been prepared by the Company pursuant to the rules and regulations of the Securities and Exchange Commission ("SEC"). They reflect all adjustments that are, in the opinion of management, necessary for a fair presentation. All such adjustments are of a normal recurring nature. The consolidated financial statements of the Company include the accounts of the Company and its wholly owned subsidiaries. The consolidated financial statements of the Company for the year ended December 31, 2014 were derived from historical financial statements of our predecessor (for the first 22 days of 2014) and financial statements of the Company (for the remainder of 2014).

Subsequent Events

The Company has evaluated events that occurred subsequent to December 31, 2016 in preparing its consolidated financial statements. The Company determined there were no events that required disclosure or recognition in these financial statements.

NOTE 2—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of the consolidated financial statements requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and the disclosure of contingent assets and liabilities in the financial statements and accompanying notes. Although management believes these estimates are reasonable, actual results could differ from these estimates. Changes in estimates are recorded prospectively. Significant assumptions are required in the valuation of proved oil and natural gas reserves that may affect the amount at which oil and natural gas properties are recorded. Estimation of asset retirement obligations ("AROs") and valuations of derivative instruments also require significant assumptions. Depletion of oil and natural gas properties are determined using estimates of proved oil and natural gas reserves. There are 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. Similarly, evaluations for impairment of proved and unproved oil and natural gas properties are subject to numerous uncertainties including, among others, estimates of future recoverable reserves and commodity price estimates. It is possible that these estimates could be revised at future dates and these revisions could be material.

Reclassifications

Certain reclassifications have been made to prior periods to conform to current period presentation. None of these reclassifications impacted previously reported equity, cash flows, or operating income amounts.

Cash and Cash Equivalents

The Company considers all highly liquid instruments with an original maturity of three months or less at the time of issuance to be cash equivalents. The Company's cash and cash equivalents are held in financial institutions in amounts that exceed the insurance limits of the Federal Deposit Insurance Corporation; however, the Company believes that the counterparties risks are minimal based on the reputation and history of the financial institutions where the deposits are held.

Derivative and Other Financial Instruments

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The Company uses derivative financial instruments to reduce exposure to fluctuations in the prices of oil and natural gas. These derivative transactions are generally in the form of collars, swaps and puts.

The Company reports the fair value of derivatives on the consolidated balance sheets in derivative instrument assets and derivative instrument liabilities as either current or noncurrent and determines the current and noncurrent classification based on the timing of expected future cash flows of individual contracts. The Company reports these amounts on a gross basis by contract.

Accounts Receivable

	As of December 31, 2016	As of December 31, 2015
	(In thousands)	
Sale of oil, natural gas and natural gas liquids	$54,422	$ 22,166
Joint interest owners	16,681	5,596
Derivatives - settled, but uncollected	—	8,561
Federal income tax receivable	2,568	—
Total accounts receivable	$73,671	$ 36,323

Accounts receivable, which are primarily from the sale of oil, natural gas and natural gas liquids (“NGLs”), are accrued based on estimates of the volumetric sales and prices the Company believes it will receive. In addition, settled but uncollected derivative contracts, receivables related to joint interest billings and income tax receivables are included in accounts receivable. The Company routinely reviews outstanding balances, assesses the financial strength of its customers and records a reserve for amounts not expected to be fully recovered. The need for an allowance is determined based upon reviews of individual accounts, historical losses, existing economic conditions and other pertinent factors. Bad debt expense was zero for each of the years ended December 31, 2016 and 2015.

Transactions with Related Parties

In the fourth quarter of 2015, the Company acquired undeveloped acreage and oil and gas producing properties from Wolfberry Partners Resources LLC ("WPR"). These properties are located in the core of the Midland Basin and had an approximate aggregate purchase price of approximately $137 million, subject to certain purchase price adjustments. The majority of WPR is owned both directly, and indirectly, by Ted Collins, Jr. and Michael W. Wallace, who are also members of our board of directors and two of our largest shareholders. Due to the related party nature of the WPR acquisition, only the disinterested members of our board of directors, consistent with our related party transaction policy, reviewed and ultimately approved the transaction. The disinterested directors also chose to hire an investment banking firm to advise them and render an opinion as to the fairness of the acquisition to the Company. Additional details of this acquisition are included in Note 3.

There were no other material related party transactions that occurred during the year ended December 31, 2015. Additionally, there were no material related party transactions that occurred during the year ended December 31, 2016.

Oil and Natural Gas Properties

The Company uses the successful efforts method of accounting for its oil and natural gas exploration and production activities. Costs incurred by the Company related to the acquisition of oil and natural gas properties and the cost of drilling development wells and successful exploratory wells are capitalized, while the costs of unsuccessful exploratory wells are expensed when determined to be unsuccessful.

The Company may capitalize interest on expenditures for significant exploration and development projects that last more than six months, while activities are in progress to bring the assets to their intended use. The Company has not capitalized any interest as projects generally lasted less than six months. Costs incurred to maintain wells and related equipment, lease and well operating costs and other exploration costs are expensed as incurred. Gains and losses arising from the sale of properties are generally included in operating income.

Capitalized acquisition costs attributable to proved oil and natural gas properties and leasehold costs are depleted on a field level, based on proved reserves, using the unit-of-production method. Capitalized exploration well costs and development costs, including AROs, are depleted on a field level, based on proved developed reserves. For the years ended December 31, 2016,

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2015, and 2014, depletion expense for oil and natural gas producing property was $194.4 million, $154.0 million, and $87.2 million respectively. Depletion expense is included in depreciation, depletion and amortization in the accompanying consolidated statements of operations.

The Company’s oil and natural gas properties as of December 31, 2016 and December 31, 2015 consisted of the following:

	December 31, 2016	December 31, 2015
	(In thousands)	
Proved oil and natural gas properties	$2,811,853	$2,197,056
Unproved oil and natural gas properties	1,833,928	878,995
Total oil and natural gas properties	4,645,781	3,076,051
Less: Accumulated depletion	(554,419)	(357,524)
Total oil and natural gas properties, net	$4,091,362	$2,718,527

In some circumstances, it may be uncertain whether proved commercial reserves have been found when drilling has been completed. Such exploratory well drilling costs may continue to be capitalized if the anticipated reserve quantity is sufficient to justify its completion as a producing well and sufficient progress in assessing the reserves and the economic and operating viability of the project is being made. As of December 31, 2016 and December 31, 2015, there were no costs capitalized in connection with exploratory wells in progress.

Capitalized costs are evaluated for impairment whenever events or changes in circumstances indicate that an asset’s carrying amount may not be recoverable. To determine if a field is impaired, the Company compares the carrying value of the field to the undiscounted future net cash flows by applying estimates of future oil and natural gas prices to the estimated future production of oil and natural gas reserves over the economic life of the property and deducting future costs. Future net cash flows are based upon our reservoir engineers’ estimates of proved reserves.

For a property determined to be impaired, an impairment loss equal to the difference between the property’s carrying value and its estimated fair value is recognized. Fair value, on a field basis, is estimated to be the present value of the aforementioned expected future net cash flows. Each part of this calculation is subject to a large degree of judgment, including the determination of the depletable units’ estimated reserves, future net cash flows and fair value. No impairment of proved property was recorded for the years ended December 31, 2016 or 2014. For the year ended December 31, 2015, impairment expense for proved properties was $19.6 million, which related to properties whose future net revenues were less than the property's carrying value. The calculation of expected future net cash flows in impairment evaluations are mainly based on estimates of future oil and natural gas prices, proved reserves and risk-adjusted probable reserve quantities, and estimates of future production and capital costs associated with our proved and risk-adjusted reserves. The Company's estimates for future oil and natural gas prices used in the impairment evaluations are based on observable prices for the next three years, and then held constant for the remaining lives of the properties. If the prices used to assess our oil and natural gas properties for impairment were 15% lower than the prices we used for such analysis, holding all other variables constant, we would not have expected to record any material impairment to our proved oil and natural properties. However, it is reasonably possible that oil and natural gas prices used in future impairment evaluations may decline, which could result in the need to impair the carrying value of the Company's proved properties.

Unproved property costs and related leasehold expirations are assessed quarterly for potential impairment and when industry conditions dictate an impairment may be possible. For the years ended December 31, 2016, 2015, and 2014 impairment expense of unproved property was $4.9 million, $14.7 million, and $4.3 million, which primarily related to management's expectation that certain leasehold interests would expire and not be renewed, along with certain leasehold interests that may expire or be sold in the future. To the extent that the Company has substantial amounts of expiring acreage in future periods, and may not be able to successfully develop this acreage due to liquidity concerns, then impairment expense may be material in those future periods. The recognition of impairment expense in these future periods may be difficult to predict.

Asset Retirement Obligation

The Company records AROs related to the retirement of long-lived assets at the time a legal obligation is incurred and the liability can be reasonably estimated. AROs are recorded as long-term liabilities with a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement cost included in the carrying amount of the related asset is allocated to expense through depletion of the asset. Changes in the liability due to passage of time are generally recognized as an increase in the carrying amount of the liability and as corresponding accretion expense.

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The Company estimates a fair value of the obligation on each well in which it owns an interest by identifying costs associated with the future down-hole plugging, dismantlement and removal of production equipment and facilities, and the restoration and reclamation of the surface acreage to a condition similar to that existing before oil and natural gas extraction began.

In general, the amount of ARO and the costs capitalized will be equal to the estimated future cost to satisfy the abandonment obligation using current prices that are escalated by an assumed inflation factor up to the estimated settlement date which is then discounted back to the date that the abandonment obligation was incurred using an estimated credit adjusted rate. If the estimated ARO changes, an adjustment is recorded to both the ARO liability and the long-lived asset. Revisions to estimated AROs can result from changes in retirement cost estimates, revisions to estimated inflation rates and changes in the estimated timing of abandonment.

After recording these amounts, the ARO liability is accreted to its future estimated value using the same assumed credit adjusted rate and the associated capitalized costs are depreciated on a unit-of-production basis.

The ARO liability consisted of the following for the period indicated:

	Year Ended December 31, 2016	Year Ended December 31, 2015
	(In thousands)	
Asset retirement obligation at beginning of period	$7,063	$ 4,873
Liabilities incurred or assumed	3,154	1,857
Liabilities settled	(30)	(3)
Accretion expense	472	336
Asset retirement obligation at end of period	$10,659	$ 7,063

Income Taxes

The following is an analysis of the Company’s consolidated income tax (benefit) expense for the periods indicated:

	Year Ended December 31,		
	2016	2015	2014 (1)
	(In thousands)		
Current	$(4,074)	$5,184	$4,338
Deferred	(14,632)	(16,867)	153,468
Income Tax (Benefit) Expense	$(18,706)	$(11,683)	$157,806

(1) In 2014, upon the corporate reorganization in connection with the IPO, the Company established a $95.2 million provision for deferred income taxes which was recognized as tax expense from continuing operations.

Deferred taxes are determined based on the estimated future tax effects of differences between the financial statement and tax basis of assets and liabilities, given the provisions of enacted tax laws. Tax positions are evaluated for recognition using a more-likely-than-not threshold, and those tax positions requiring recognition are measured as the largest amount of tax benefit that is greater than fifty percent likely of being realized upon ultimate settlement with a taxing authority that has full knowledge of all relevant information. The Company’s policy is to record interest and penalties relating to uncertain tax positions in income tax expense. At December 31, 2016, the Company had a long-term tax payable related to uncertain tax positions totaling $5.3 million. This amount is recorded in other long term liabilities on the consolidated balance sheet. The total unrecognized tax benefits, that if recognized, would have impacted the effective income tax rate as of the end of 2016 was $3.8 million.

The Company's U.S. federal income tax returns for 2013 and beyond, and its Texas franchise tax returns for 2012 and beyond, remain subject to examination by the taxing authorities. No other jurisdiction's returns are significant to the Company's financial position.

Revenue Recognition

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The Company records oil and natural gas sales when title passes to the purchaser, which for the Company is primarily at the wellhead. Oil and natural gas production imbalances, which there were none, are accounted for using the sales method.

Segment Reporting

The Company operates in only one industry segment: the oil and natural gas exploration and production industry in the United States. All of its operations are conducted in one geographic area of the United States. All revenues are derived from customers located in the United States.

New Accounting Pronouncements

In March 2016, the Financial Accounting Standards Board (“FASB”) issued Accounting Standard Update ("ASU") 2016-09, “Compensation - Stock Compensation Topic 718: Improvements to Employee Share-Based Payment Accounting," which simplifies several aspects of the accounting for share-based payment award transactions. These simplifications include the income tax consequences, classification of awards as either equity or liabilities, and classification on the statement of cash flows. Public entities are required to apply ASU 2016-09 for annual and interim reporting periods beginning after December 15, 2016. The Company does not expect the adoption of this standard to have a material impact on its consolidated financial statements.

In May 2014, the FASB issued ASU 2014-09, “Revenue from Contracts with Customers (Topic 606),” which provides a comprehensive revenue recognition standard for contracts with customers that supersedes current revenue recognition guidance including industry specific guidance. As a result of a recent deferral by the FASB, an entity is required to apply ASU 2014-09 for annual and interim reporting periods beginning after December 15, 2017. An entity can apply ASU 2014-09 using either a full retrospective method, meaning the standard is applied to all of the periods presented, or a modified retrospective method, meaning the cumulative effect of initially applying the standard is recognized in the most current period presented in the financial statements. The Company has not yet selected a transition method and is currently evaluating the impact of its pending adoption of this guidance on its consolidated financial statements; however, it has not identified any revenue stream that would be materially impacted and does not expect the adoption of this standard to have a material impact on our consolidated financial statements.

In February 2016, the FASB issued ASU 2016-02, “Leases (Topic 842)," which generally requires all lease transactions (with terms in excess of 12 months) to be recognized on the balance sheet as lease assets and lease liabilities. Public entities are required to apply ASU 2016-02 for annual and interim reporting periods beginning after December 15, 2018 with early adoption permitted. The Company is currently evaluating the impact of its pending adoption of this guidance on its consolidated financial statements; however, based on the Company's current operating leases, the adoption of this standard is not expected to have a material impact on our consolidated financial statements.

In August 2014, the FASB issued ASU 2014-15, “Disclosure of Uncertainties About an Entity’s Ability to Continue as a Going Concern,” which requires a company’s management to evaluate whether there are conditions and events that raise substantial doubt about the entity’s ability to continue as a going concern within one year after the financial statements are issued (or available to be issued when applicable). An entity is required to apply ASU 2014-15 for annual and interim reporting periods after December 15, 2016. The adoption of this guidance in the fourth quarter of 2016 had no impact on the Company's consolidated financial statements.

In September 2015, the FASB issued ASU 2015-16, “Simplifying the Accounting for Measurement-Period Adjustments," which requires the acquirer in a business combination recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. Public entities are required to apply ASU 2015-16 for annual and interim reporting periods beginning after December 15, 2015. The adoption of this guidance in the first quarter of 2016 did not have a material effect on the Company's consolidated financial statements.

In April 2015, the FASB issued ASU 2015-03, “Simplifying the Presentation of Debt Issuance Costs." which requires debt issuance costs to be presented in the balance sheet as a direct deduction from the carrying amount of the debt obligation, similar to debt discounts. The Company adopted this guidance in the first quarter of 2016. Accordingly, debt issuance costs in the amount of $12.1 million which were formerly classified as long-term assets at December 31, 2015 have been reclassified as a deduction from the carrying amount of our senior notes in the consolidated balance sheet.

NOTE 3—ACQUISITIONS OF OIL AND NATURAL GAS PROPERTY INTERESTS

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Silver Hill Acquisitions

On October 13, 2016, the Company entered into definitive agreements to acquire 100% of Silver Hill Energy Partners, LLC ("SHEP I") and Silver Hill E&P II, LLC ("SHEP II", and together with SHEP I, "Silver Hill") for $1.25 billion of cash and 31.0 million shares of RSP Inc. common stock in aggregate. Silver Hill is comprised of two privately-held entities that collectively own oil and gas producing properties and undeveloped acreage in Loving and Winkler counties in Texas and owns approximately 40,100 net acres. Silver Hill's highly contiguous acreage position in the core of the Delaware Basin is complementary to the Company's asset base and the acquisition creates substantial scale from a production and acreage standpoint. The majority of the purchase price will be recorded to proved and unproved oil and natural gas properties on the Company's balance sheet.

The SHEP I acquisition closed on November 28, 2016, with a cash cost of $604 million, including assumed debt obligations which were repaid, before purchase price adjustments, and approximately 15.0 million shares of RSP Inc. common stock. A summary of the consideration transferred and the fair value of assets and liabilities acquired is as follows (in thousands, except shares):

Value of the Company’s common stock issued in the SHEP I acquisition (1)	$595,919
Cash paid to sellers in the SHEP I acquisition	531,196
Total consideration for the assets contributed in the SHEP I acquisition	$1,127,115
Fair value of oil and natural gas properties	$1,200,632
Asset retirement obligation	(666)
Assumption of debt	(63,826)
Assumption of other liabilities	(9,025)
Total net assets acquired (2)	$1,127,115

(1) The Company issued 14,980,362 shares of common stock at $39.78 per share (closing price) on November 28, 2016.
(2) Approximately 85% of the acquisition date fair value of oil and natural gas properties was recorded as unproved property.

The acquisition of SHEP I was accounted for using the acquisition method of accounting with the Company as the acquirer. Under the acquisition method of accounting, the Company recorded all assets acquired and liabilities assumed at their respective acquisition date fair values at the closing date of the acquisition. The fair values of the assets acquired and liabilities assumed are based on a detailed analysis, using industry accepted methods of estimating the current fair value as described below.

For the SHEP I acquisition, which closed on November 28, 2016, substantially all of the value of the transaction was related to the value of the oil and gas assets acquired with minimal value ascribed to the other assets. The Company used two valuation methods in its determination of fair value for the oil and natural gas properties; the discounted cash flow analysis and comparable transaction analysis. The significant assumptions included in the discounted cash flow analysis include commodity price assumptions, costs and capital outlay to develop the acquired properties, pricing differentials, reserve risking, and discount rates. NYMEX strip pricing at the SHEP I acquisition date of November 28, 2016, less applicable pricing differentials, was utilized in the discounted cash flow analysis. Risking levels in the discounted cash flow analysis are determined based on a variety of factors, such as existing well performance, offset production and analogue wells. Discount rates used in the discounted cash flow analysis were determined by using the estimated weighted average cost of capital for the Company, discount rates published in third party publications, as well as industry knowledge and experience. The comparable transaction analysis was performed to establish a range of fair values for similarly situated oil and gas properties that were recently bought or sold in arms-length, observable market transactions. The range of value observed from the Company’s analysis of recent market transactions was then utilized as a basis for evaluating the fair value determined via the discounted cash flow method. The Company’s fair value conclusion indicated that the discounted cash flow method valuation is substantially in the same range as the comparable transactions reviewed, when considering the comparable transactions on a median or average basis. Other current liabilities assumed in the SHEP I acquisition, which related to revenues held in suspense, were carried over at historical carrying values because the assets and liabilities are short term in nature and their carrying values are estimated to represent the best estimate of fair value.

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Revenues and earnings of SHEP I recognized in 2016 subsequent to the acquisition date were$7.1 million and $2.6 million. The Company recognized $6.4 million of expenses related to the SHEP I acquisition in 2016 that are recorded in Acquisition costs on the consolidated statement of operations.

The SHEP II acquisition is expected to close in March 2017 with an estimated cash cost of $646 million, before purchase price adjustments, and the issuance of 16.0 million shares of RSP Inc. common stock. As part of the Silver Hill acquisitions, we were required to prepay to an escrow account of approximately $64.1 million as part of the SHEP II acquisition. This amount is included in long-term other assets as of December 31, 2016. Due to the large number of shares that will be issued in these acquisitions, the issuance of RSP Inc. common stock for the SHEP II acquisition was subject to shareholder approval. The fair value of the RSP common stock issued in the acquisition of SHEP II, used to record the purchase price of these acquisitions in the financial statements, will be determined based on the trading price of this stock on the date of issuance. The final purchase price of this acquisition and the fair value of the assets acquired and liabilities assumed will be reflected when the acquisition closes.

Other 2016 Acquisitions

During 2016, the Company also completed bolt-on acquisitions of mostly undeveloped acreage in the Midland Basin for an aggregate total purchase price of approximately $69.4 million. The acquisitions included additional working interests in properties where the Company owned existing interests as well as other properties in the Company's core areas. These acquisitions were funded with cash on hand.

WPR Acquisition

In the fourth quarter of 2015, the Company acquired undeveloped acreage and oil and gas producing properties for an aggregate purchase price of approximately $137 million, subject to certain purchase price adjustments, from Wolfberry Partners Resources LLC ("WPR"), an entity partly owned by affiliates of the Company. Approximately $41.0 million was recorded as proved oil and gas properties. The acquisition included 4,100 largely contiguous net acres, in the core of the Midland Basin with production of approximately 1,900 Boe/d and 86 net horizontal drilling locations as of the effective date.

Glass Ranch Acquisition

In the third quarter of 2015, the Company acquired undeveloped acreage and oil and gas producing properties located in Martin and Glasscock counties for an aggregate purchase price of approximately $313 million, subject to certain purchase price adjustments. The aggregate acquisitions include 6,548 net acres in our core focus area with an average royalty burden of approximately 23%, with production of approximately 1,680 Boe/d and 191 net horizontal drilling locations as of the effective date.

Pro Forma Results

The Company’s summary pro forma results for the twelve months ended December 31, 2016 and 2015 were derived from the actual results of the Company adjusted to reflect the SHEP I acquisition, as if such transaction had occurred on January 1, 2015. The below information reflects pro forma adjustments for the issuance of RSP Inc. common stock to the sellers of SHEP I along with RSP Inc. common stock issued in the October 2016 public offering that funded the cash portion of the SHEP I acquisition. Additional pro forma adjustments, based on available information and certain assumptions that we believe are factually supportable, included (i) the depletion of SHEP I fair-valued proved oil and gas properties, and (ii) the estimated tax impacts of the pro forma adjustments. Pro forma earnings for the year ended December 31, 2016 were adjusted to exclude $6.4 million of acquisition costs incurred by the Company.

The pro forma financial information included below does not give effect to certain acquisitions that were immaterial to our actual and pro forma results for the periods reflected below and does not make any adjustments for non-recurring expenses associated with the SHEP I acquisition.

The unaudited pro forma financial information does not purport to be indicative of results of operations that would have occurred had the transaction occurred on the basis assumed above, nor is such information indicative of expected future results of operations.

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	Year Ended December 31, 2016		Year Ended December 31, 2015	
	Actual	Pro Forma	Actual	Pro Forma
	(In thousands)		(In thousands)	
Revenues	$353,857	$404,279	$283,992	$299,373
Net loss	$(24,851)	$(13,887)	$(18,254)	$(26,363)
Net loss per share:				
Basic	$(0.23)	$(0.10)	$(0.21)	$(0.21)
Diluted	$(0.23)	$(0.10)	$(0.21)	$(0.21)

NOTE 4—DERIVATIVE INSTRUMENTS

Commodity Derivative Instruments

The Company uses derivative instruments to manage its exposure to cash-flow variability from commodity-price risk inherent in its crude oil and natural gas production. These include collar contracts, swaps, and deferred premium put options. The derivative instruments are recorded at fair value on the consolidated balance sheets and any gains and losses are recognized in current period earnings.

Each collar transaction has an established price floor and ceiling, and certain collar transactions also include a short put as well. When the settlement price is below the price floor established by these collars, the Company receives an amount from its counterparty equal to the difference between the settlement price and the price floor multiplied by the hedged contract volume. When the settlement price is above the price ceiling established by these collars, the Company pays its counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the hedged contract volume. When the settlement price is below the short put price, the Company pays its counterparty an amount equal to the difference between the settlement price and the short put price multiplied by the hedged contract volume. Cumulatively, when the settlement price is below the short put price, the Company would receive from its counterparty an amount equal to the difference of the price floor and the short put price multiplied by the hedged contract volume.

Each deferred premium put option has an established floor price. When the settlement price is below the floor price, the Company receives the difference between the floor price and the settlement price multiplied by the hedged contract volume less the cost of the premium for the option. When the settlement price is at or above the floor price, the Company receives no proceeds and pays the cost of the premium for the option. In either case, whether the settlement price is below or above the floor price, the Company pays the premium for the option at the expiration of the option. When the settlement price is below the short put price, the Company pays its counterparty an amount equal to the difference between the settlement price and the short put price multiplied by the hedged contract volume.

Each swap transaction has an established fixed price. When the settlement price is above the fixed price, the Company pays its counterparty 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 below the fixed price, the counterparty pays the Company an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume.

The following table summarizes all open positions as of December 31, 2016:

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	Contracts expiring quarter ending: March 31, 2017	June 30, 2017	September 30, 2017	December 31, 2017	Total (5)
Crude Oil Collars:					
Notional volume (Bbl)	675,000				675,000
Weighted average ceiling price ($/Bbl)(1)	$54.25				$ 54.25
Weighted average floor price ($/Bbl)(1)	$45.00				$ 45.00
Weighted average short put price ($/Bbl)(1)	$35.00				$ 35.00
Crude Oil Costless Collars:					
Notional volume (Bbl)	450,000	1,137,500	1,150,000	1,150,000	3,887,500
Weighted average ceiling price ($/Bbl)(1)	$59.75	$ 60.05	$ 60.05	$ 60.05	$ 60.02
Weighted average floor price ($/Bbl)(1)	$45.00	$ 45.00	$ 45.00	$ 45.00	$ 45.00
Crude Oil Deferred Premium Puts:					
Notional volume (Bbl)		910,000	920,000	920,000	2,750,000
Weighted average floor price ($/Bbl)(1)		$ 48.50	$ 48.50	$ 48.50	$ 48.50
Weighted average deferred premium ($/Bbl) (2)		$ (4.00)	$ (4.00)	$ (4.00)	$ (4.00)
Deferred Premium Put Spreads:					
Notional volume (Bbl)	675,000				675,000
Weighted average floor price ($/Bbl)(1)	$45.00				$ 45.00
Weighted average short put price ($/Bbl)(1)	$35.00				$ 35.00
Weighted average deferred premium ($/Bbl) (2)	$(2.32)				$ (2.32)
Natural Gas Costless Collars:					
Notional volume (MMBtu)	1,955,000	2,366,000	2,422,000	2,545,000	9,288,000
Weighted average ceiling price ($/MMbtu)(3)	$3.83	$ 3.86	$ 3.86	$ 3.86	$ 3.85
Weighted average floor price ($/MMbtu)(3)	$3.00	$ 3.00	$ 3.00	$ 3.00	$ 3.00
Mid-Cush Differential (Basis) Swaps:					
Notional volume (Bbl)	1,350,000	1,365,000	276,000	276,000	3,267,000
Weighted average swap price ($/Bbl)(4)	$(0.21)	$ (0.21)	$ (0.50)	$ (0.50)	$ (0.26)

(1) The crude oil derivative contracts are settled based on the month's average daily NYMEX price of West Texas Intermediate Light Sweet Crude.
(2) The deferred premium is not paid until the expiration date, aligning cash inflows and outflows with the settlement of the derivative contract.
(3) The natural gas derivative contracts are settled based on the last trading day's closing price for the front month contract relevant to each period.
(4) The Mid-Cush swap contracts are settled based on the difference in the arithmetic average during the calculation period of WTI MIDLAND ARGUS and WTI ARGUS prices in the Argus Americas Crude publication for the relevant period.
(5) Subsequent to December 31, 2016, the Company entered into hedges covering certain periods of 2018.

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Derivative Fair Values and Gains (Losses)

The following table presents the fair value of derivative instruments. The Company's derivatives are presented as separate line items in its consolidated balance sheets as current and noncurrent derivative instrument assets and liabilities based on the expected settlement dates of the instruments. The fair value amounts are presented on a gross basis and do not reflect the netting of asset and liability positions permitted under the terms of the Company's master netting arrangements. See Note 5 for further discussion related to the fair value of the Company's derivatives.

	Assets		Liabilities	
	December 31, 2016	December 31, 2015	December 31, 2016	December 31, 2015
	(In thousands)			
Derivative Instruments:				
Current amounts				
Commodity contracts	$11,815	$ 8,452	$28,861	$ 3,994
Total derivative instruments	$11,815	$ 8,452	$28,861	$ 3,994

Gains and losses on derivatives are reported in the consolidated statements of operations.

The following represents the Company's reported gains (losses) on derivative instruments for the periods presented:

	Year Ended December 31,		
	2016	2015	2014
	(In thousands)		
Gain (loss) on derivative instruments:			
Commodity derivative instruments	$(23,760)	$20,906	$81,470
Total	$(23,760)	$20,906	$81,470

Offsetting of Derivative Assets and Liabilities

The following table presents the Company's gross and net derivative assets and liabilities.

	Gross Amount Presented on Balance Sheet	Netting Adjustments(a)	Net Amount
	(In thousands)		
December 31, 2016			
Derivative instrument assets with right of offset or master netting agreements	$11,815	$ (11,815)	$—
Derivative instrument liabilities with right of offset or master netting agreements	$(28,861)	$ 11,815	$(17,046)
December 31, 2015			
Derivative instrument assets with right of offset or master netting agreements	$8,452	$ (3,994)	$4,458
Derivative instrument liabilities with right of offset or master netting agreements	$(3,994)	$ 3,994	$—

(a) With all of the Company's financial trading counterparties, the Company has agreements in place that allow for the financial right of offset for derivative assets and derivative liabilities at settlement or in the event of a default under the agreements.

Credit-Risk Related Contingent Features in Derivatives

None of the Company’s derivative instruments contain credit-risk related contingent features. No amounts of collateral were posted by the Company related to net positions as of December 31, 2016 and December 31, 2015.

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NOTE 5—FAIR VALUE MEASUREMENTS

The book values of cash and cash equivalents, accounts receivable, accounts payable and accrued liabilities approximate fair value due to the short-term nature of these instruments. The book value of the Company's credit facilities approximate fair value as the interest rates are variable. At December 31, 2016, the fair value of the Company's 6.625% senior notes was $735.0 million and the fair value of the Company's 5.25% senior notes was $452.3 million. If the Company recorded the 6.625% senior notes at fair value they would be Level 1 in our fair value hierarchy as they are traded in an active market with quoted prices for identical instruments. If the Company recorded the 5.25% senior notes at fair value they would be Level 2 in our fair value hierarchy as these notes have not been registered and do not trade in an active market. The fair value of derivative financial instruments is determined utilizing industry standard models incorporating assumptions and inputs, most of which are substantially observable in active markets throughout the full term of the instruments. These include market price curves, contract terms and prices, credit risk adjustments, implied market volatility and discount factors.

The Company has categorized its assets and liabilities measured at fair value, based on the priority of inputs to the valuation technique, into a three-level fair value hierarchy. The fair value hierarchy gives the highest priority to quoted prices in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3).

Assets and liabilities recorded at fair value on the consolidated balance sheets are categorized based on the inputs to the valuation techniques as follows:

•Level 1—Assets and liabilities recorded at fair value for which values are based on unadjusted quoted prices for identical assets or liabilities in an active market that management has the ability to access. Active markets are considered to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.
•Level 2—Assets and liabilities recorded at fair value for which values are based on quoted prices in markets that are not active or model inputs that are observable either directly or indirectly for substantially the full term of the asset or liability. Substantially all of these inputs are observable in the marketplace throughout the full term of the price risk management instrument and can be derived from observable data or supported by observable levels at which transactions are executed in the marketplace.
•Level 3—Assets and liabilities recorded at fair value for which values are based on prices or valuation techniques that require inputs that are both unobservable and significant to the overall fair value measurement. Unobservable inputs that are not corroborated by market data and may reflect management's own assumptions about the assumptions a market participant would use in pricing the asset or liability.

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.

Fair Value Measurement on a Recurring Basis

The following table presents, by level within the fair value hierarchy, the Company's assets and liabilities that are measured at fair value on a recurring basis.

	Level 1	Level 2	Level 3	Total fair value
	(In thousands)			
As of December 31, 2016:				
Commodity derivative instruments	$ —	$ (17,046)	$ —	$ (17,046)

Total	$—	$(17,046)	$ —	$ (17,046)

	Level 1	Level 2	Level 3	Total fair value
	(In thousands)			
As of December 31, 2015:				
Commodity derivative instruments	$—	$4,458	$ —	$ 4,458
Total	$—	$4,458	$ —	$ 4,458

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Significant Level 2 assumptions used to measure the fair value of the commodity derivative instruments include implied volatility factors, appropriate risk adjusted discount rates, as well as other relevant data.

Reclassifications of fair value among Level 1, Level 2 and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter. There were no transfers among Level 1, Level 2 or Level 3 during the years ended December 31, 2016 and 2015.

Nonfinancial Assets and Liabilities

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

The Company reviews its proved oil and natural gas properties for impairment purposes by comparing the expected undiscounted future cash flows at a producing field level to the unamortized capitalized cost of the asset. Significant assumptions associated with the calculation of future cash flows used in the impairment analysis include the estimate of future commodity prices, production costs, development expenditures, production, risk-adjusted discount rates and other relevant data. As such, the fair value of oil and natural gas properties used in estimating impairment represents a nonrecurring Level 3 measurement.

NOTE 6—LONG-TERM DEBT

Long-term debt consists of the following:

	December 31, 2016	December 31, 2015
	(In millions)	
Revolving credit facility	$—	$ —
5.25% Senior Notes	450.0	—
6.625% Senior Notes	700.0	700.0
Less: Discount	(1.1)	(1.4)
Less: Debt issuance costs	(16.6)	(12.1)
Total long-term debt	$1,132.3	$ 686.5

Credit Agreement

The Company's revolving credit facility requires it to maintain the following two financial ratios:

•a working capital ratio, which is the ratio of consolidated current assets (includes unused commitments under its revolving credit facility and excludes restricted cash and derivative assets) to consolidated current liabilities (excluding the current portion of long-term debt under the credit facility and derivative liabilities), of not less than 1.0 to 1.0;

•a leverage ratio, which is the ratio of the sum of all of the Company’s debt to the consolidated EBITDAX (as defined in the credit agreement) for the four fiscal quarters then ended, of not greater than 4.25 to 1.0. For the fiscal quarters ending December 31, 2016, March 31, 2017 and June 30, 2017, the consolidated EBITDAX shall be deemed to equal (A) consolidated EBITDAX for the one fiscal quarter period ending December 31, 2016 multiplied by 4, (B) consolidated EBITDAX for the two fiscal quarter period ending March 31, 2017 multiplied by 2 and (C) consolidated EBITDAX for the three fiscal quarter period ending June 30, 2017 multiplied by 4/3, respectively.

The Company's revolving credit facility contains restrictive covenants that may limit its ability to, among other things, incur additional indebtedness, make loans to others, make investments, enter into mergers, make or declare dividends, enter into commodity hedges exceeding a specified percentage or its expected production, enter into interest rate hedges exceeding a specified percentage of its outstanding indebtedness, incur liens, sell assets or engage in certain other transactions without the prior consent of the lenders.

The Company was in compliance with such covenants and ratios as of December 31, 2016.

Principal amounts borrowed are payable on the maturity date, and interest is payable quarterly for base rate loans and at the end of the applicable interest period for Eurodollar loans. The Company has a choice of borrowing at a Eurodollar rate or at the adjusted base rate. Eurodollar loans bear interest at a rate per annum equal to an adjusted LIBOR rate (equal to the quotient of: (i) the LIBOR Rate; divided by (ii) a percentage equal to 100% minus the maximum rate on such date at which the Administrative Agent is required to maintain reserves on "Eurocurrency Liabilities" as defined in and pursuant to Regulation D of the Board of Governors of the Federal Reserve System) plus an applicable margin ranging from 200 to 300 basis points, depending on the percentage of its borrowing base utilized. Alternate base rate loans bear interest at a rate per annum equal to the greatest of: (i) the agent bank's referenced rate; (ii) the federal funds effective rate plus 50 basis points; and (iii) the adjusted LIBOR rate plus 100 basis points, plus an applicable margin ranging from 100 to 200 basis points, depending on the percentage of our borrowing base utilized, plus a commitment fee ranging from 37.5 basis points to 50 basis points charged on the undrawn commitment amount. As of December 31, 2016, we had no borrowings and $0.6 million of letters of credit outstanding under our revolving credit facility and $899.4 million of borrowing capacity.

The amount available to be borrowed under the revolving credit facility is subject to a borrowing base that is re-determined semiannually each May and November and depends on the volumes of proved oil and natural gas reserves and estimated cash flows from these reserves and commodity hedge positions. As of December 31, 2016, the borrowing base under the Company's amended and restated credit agreement is $950 million, with an elected commitment of $900 million, and lender commitments of $2.5 billion. The maturity date of the Company's revolving credit facility is December 19, 2021.

Senior Notes Due 2025

On December 27, 2016, the Company issued $450 million of 5.25% senior unsecured notes at par through a private placement. The notes will mature on January 15, 2025. The notes are senior unsecured obligations that rank equally with all of our future senior indebtedness, are as a result of being unsecured effectively subordinated in rights to our assets constituting collateral held by all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including indebtedness under RSP LLC's revolving credit facility, and will rank senior to any future subordinated indebtedness of the Company. Interest on these notes is payable semi-annually on January 15 and July 15, commencing on July 15, 2017. On or after January 15, 2020, the Company may redeem some or all of the notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 103.938% of principal, declining in twelve-month intervals to 100% in 2023 and thereafter. In addition, prior to January 15, 2020, on any one or more occasions, the Company may redeem all or part of the notes at a redemption price of 100% of the principal amount of the notes redeemed, plus an applicable make-whole premium along with accrued and unpaid interest.

The Company incurred approximately $5.9 million of debt issuance costs related to the 2016 note issuance, which are a reduction to "Long-term debt" on the Company's consolidated balance sheets and will be amortized to interest expense, net, over the life of the notes using the effective interest method. In the event of certain changes in control of the Company, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. RSP LLC and SHEP I, our 100% owned subsidiaries, have fully and unconditionally guaranteed the notes. RSP Inc. does not have independent assets or operations. The terms of the notes include, among other restrictions, limitations on our ability to repurchase shares, incur debt, create liens, make investments, transfer or sell assets, enter into transactions with affiliates and consolidate, merge or transfer all or substantially all of our assets. The Company was in compliance with the provisions of the indenture governing the senior unsecured notes as of December 31, 2016.

Senior Notes Due 2022

On September 26, 2014, the Company issued $500.0 million of 6.625% senior unsecured notes at par through a private placement. On August 10, 2015, the Company issued an additional $200.0 million of these notes at 99.25% of the principal amount through a private placement. The notes will mature on October 1, 2022. The notes are senior unsecured obligations that rank equally with all of our future senior indebtedness, are effectively subordinated to all our existing and future secured indebtedness to the extent of the value of the collateral securing such indebtedness, including borrowings under RSP LLC's revolving credit facility, and will rank senior to any future subordinated indebtedness of the Company. Interest on these notes

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is payable semi-annually on April 1 and October 1. On or after October 1, 2017, the Company may redeem some or all of the notes, with certain restrictions, at a redemption price, plus accrued and unpaid interest, of 104.969% of principal, declining in twelve-month intervals to 100% in 2020 and thereafter. In addition, prior to October 1, 2017, the Company may redeem up to 35% of the principal amount of the notes with the net proceeds of qualified offerings of our equity at a redemption price of 106.625% of the principal amount of the notes, plus accrued and unpaid interest.

The Company incurred approximately $11.3 million of debt issuance costs related to the 2014 note issuance and $2.4 million related to the 2015 note issuance, which are a reduction to “Long-term debt” on the Company's consolidated balance sheets and will be amortized to interest expense, net, over the life of the notes using the effective interest method. In the event of certain changes in control of the Company, each holder of notes will have the right to require us to repurchase all or any part of the notes at a purchase price in cash equal to 101% of the principal amount, plus accrued and unpaid interest to the date of purchase. RSP LLC, our 100% owned and only subsidiary, has fully and unconditionally guaranteed the notes. RSP Inc. does not have independent assets or operations. The terms of the notes include, among other restrictions, limitations on our ability to repurchase shares, incur debt, create liens, make investments, transfer or sell assets, enter into transactions with affiliates and consolidate, merge or transfer all or substantially all of our assets. In June 2015, the Company exchanged $500.0 million of these notes for registered notes with the same terms. In March 2016, the Company exchanged an additional $200.0 million of these notes for registered notes with the same terms. The Company was in compliance with the provisions of the indenture governing the senior unsecured notes as of December 31, 2016.

NOTE 7—COMMITMENTS AND CONTINGENCIES

Legal Matters

In the ordinary course of business, the Company may at times be subject to claims and legal actions. Management believes it is remote that the impact of such matters will have a material adverse effect on the Company’s financial position, results of operations or cash flows.

Environmental Matters

The Company is subject to various federal, state and local laws and regulations relating to the protection of the environment. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed as incurred. The Company has established procedures for the ongoing evaluation of its operations to identify potential environmental exposures and to comply with regulatory policies and procedures.

The Company accounts for environmental contingencies in accordance with the accounting guidance related to accounting for contingencies. Environmental expenditures that relate to current operations are expensed or capitalized as appropriate. Expenditures that relate to an existing condition caused by past operations, which do not contribute to current or future revenue generation, are expensed.

Liabilities are recorded when environmental assessments and/or clean-ups are probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. At both December 31, 2016 and 2015, the Company had no environmental matters requiring specific disclosure or requiring the recognition of a liability.

Leases

The Company leases office space in Midland and Dallas Texas. These leases run through 2019 and 2021, respectively. Rent expense for the years ended December 31, 2016, 2015, and 2014 was $0.9 million and $0.9 million, and $0.5 million respectively.

Contractual Obligations

A summary of the Company's contractual obligations as of December 31, 2016 is provided in the following table (in thousands).

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	Payments Due by Period For the Year Ended December 31,						
	2017	2018	2019	2020	2021	Thereafter	Total
	(In thousands)						
Revolving credit facility (1)	$—	$—	$—	$—	$—	$—	$—
5.25% Senior Notes (2)	—	—	—	—	—	450,000	450,000
6.625% Senior Notes (2)	—	—	—	—	—	700,000	700,000
Interest cost (3)	58,508	70,000	70,000	70,000	70,000	129,063	467,571
Drilling rig commitments (4)	6,776	—	—	—	—	—	6,776
Office and equipment leases	1,094	1,357	1,070	160	69	—	3,750
Asset retirement obligations (5)	—	—	—	—	—	10,659	10,659
Total	$66,378	$71,357	$71,070	$70,160	$70,069	$1,289,722	$1,638,756

(1) This table does not include future commitment fees, amortization of deferred financing costs, interest expense or other fees on our revolving credit facility because obligations thereunder are floating rate instruments and we cannot determine with accuracy the timing of future loan advances, repayments or future interest rates to be charged. Any borrowings under the revolving credit facility must be repaid by August 2019.
(2) Includes principal only.
(3) Related to fixed rate debt only, which is the 5.25% Senior Notes and the 6.625% Senior Notes.
(4) The values in the table represent the gross amounts that the Company is committed to pay.
(5) 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.

NOTE 8—EQUITY-BASED COMPENSATION

Equity-based compensation expense, which was recorded in general and administrative expenses, was $13.8 million, $9.4 million, and $20.2 million for the years ended December 31, 2016, 2015 and 2014, respectively. Equity-based compensation expense in the 2014 period includes expense related to incentive units. Expenses related to incentive units are described in more detail below. Incentive unit expense, which was also recorded in General and administrative expenses, was $14.7 million for the year ended December 31, 2014.

Restricted Stock Awards

In connection with the IPO, the Company adopted the RSP Permian, Inc. 2014 Long Term Incentive Plan (the “LTIP”) for the employees, consultants and directors of the Company and its affiliates who perform services for the Company.

Equity-based compensation expense for awards under the LTIP was $7.9 million, $6.4 million and $4.7 million for the years ended December 31, 2016, 2015 and 2014, respectively.

The Company views restricted stock awards with graded vesting as single awards with an expected life equal to the average expected life and amortize the awards on a straight-line basis over the life of the awards.

The compensation expense for these awards was determined based on the market price of the Company’s common stock at the date of grant applied to the total number of shares that were anticipated to fully vest. As of December 31, 2016, the Company had unrecognized compensation expense of $8.5 million related to restricted stock awards which is expected to be recognized over a weighted average period of 1.6 years.

The following table represents restricted stock award activity for the years ended December 31, 2016 and 2015:

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	2016		2015		2014	
	Shares	Weighted Average Fair Value	Shares	Weighted Average Fair Value	Shares	Weighted Average Fair Value
Restricted shares outstanding, beginning of period	499,529	$ 25.99	477,767	$ 23.71	—	$ —
Restricted shares granted	442,835	19.78	279,181	27.18	489,544	23.69
Restricted shares canceled	(13,551)	21.61	(6,640)	26.43	(11,777)	23.03
Restricted shares vested	(271,918)	25.22	(250,779)	22.97	—	—
Restricted shares outstanding, end of period	656,895	$ 22.21	499,529	$ 25.99	477,767	$ 23.71

Performance-Based Restricted Stock Awards

In June 2014, performance-based restricted stock awards were granted containing predetermined market conditions with a cliff vesting period of 2.75 years. We granted 134,400 of these shares at a 100% of target payout while the conditions of the grants allow for a payout ranging between no payout and 200% of target. In March 2015, an additional grant of performance-based restricted stock awards were granted containing predetermined market conditions with a cliff vesting period of 2.83 years. We granted 159,932 of these shares at a 100% of target payout while the conditions of the grants allow for a payout ranging between no payout and 200% of target. In February 2016, an additional grant of performance-based restricted stock awards were granted containing predetermined market conditions with a cliff vesting period of 2.92 years. We granted 484,650 of these shares at a 100% of target payout while the conditions of the grants allow for a payout ranging from no payout and 100% of target payout.

Equity-based compensation for these awards was $5.9 million, $3.0 million, and $0.8 million for the years ended December 31, 2016, 2015 and 2014, respectively.

The compensation expense for these performance based awards is based on a per share value using a Monte-Carlo simulation. The payout level is calculated based on actual total shareholder return performance achieved during the performance period compared to a defined peer group of comparable public companies. The unrecognized compensation expense related to these shares is approximately $6.2 million as of December 31, 2016 and is expected to be recognized over the next 1.51 years.

The following table represents performance-based restricted stock award activity for the years ended December 31, 2016 and 2015:

	2016		2015		2014	
	Shares	Weighted Average Fair Value	Shares	Weighted Average Fair Value	Shares	Weighted Average Fair Value
Restricted shares outstanding, beginning of period	294,332	$ 31.41	134,400	$ 28.14	—	$ —
Restricted shares granted	484,650	13.53	159,932	31.74	134,400	28.14
Restricted shares vested	(31,108)	$ 31.39	—	$ —	—	$ —
Restricted shares outstanding, end of period	747,874	$ 19.82	294,332	$ 31.41	134,400	$ 28.14

Incentive Units

Pursuant to the LLC Agreement of RSP LLC, certain incentive units were available to be issued to the Company’s management and employees. After successful completion of the IPO, the performance conditions associated with certain incentive units were deemed probable of reaching payout. For the year ended December 31, 2014, the Company recognized non-cash compensation expense of $14.7 million, respectively, related to these incentive units. In December 2014, the incentive unit plan was concluded and all awards remaining under the incentive unit plans were allocated according to performance criteria established at the adoption of the plan. These incentive units determined the stock allocation of shares held by RSP Permian Holdco, between management and NGP and had no dilutive impact, or cash impact, to shareholders of

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RSP Permian, Inc. In periods subsequent to 2014, there will be no additional expense recognized related to these incentive units.

NOTE 9—EARNINGS PER SHARE

The Company's basic earnings per share amounts have been computed using the two-class method based on the weighted-average number of shares of common stock outstanding for the period. Because the Company recognized a net loss for the years ended December 31, 2016 and 2015, all unvested restricted share awards were excluded from the diluted earnings per share calculations as they would be antidilutive. A reconciliation of the components of basic and diluted earnings per common share is presented in the table below:

	Year Ended December 31,		
	2016	2015	2014
	(In thousands)		
Numerator:			
Net income available to stockholders	$(24,851)	$(18,254)	$2,498
Basic net income allocable to participating securities (1)	—	—	15
Income available to stockholders	$(24,851)	$(18,254)	$2,483
Denominator:			
Weighted average number of common shares outstanding - basic	107,324	86,770	71,898
Effect of dilutive securities:			
Restricted stock	—	—	—
Weighted average number of common shares outstanding - diluted	107,324	86,770	71,898
Net income per share:			
Basic	$(0.23)	$(0.21)	$0.03
Diluted	$(0.23)	$(0.21)	$0.03

(1) Restricted share awards that contain non-forfeitable rights to dividends are participating securities and, therefore, are included in computing earnings using the two-class method. Participating securities, however, do not participate in undistributed net losses.

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NOTE 10—INCOME TAXES

The components of the provision for income taxes for the year ended December 31, 2016, 2015, and 2014 is as follows:

	For the year ended December 31,		
	2016	2015	2014
		(In thousands)	
Current Income Tax Expense (Benefit):			
Federal	$(4,074)	$ 5,504	$4,111
State	—	(320)	227
Total income tax expense (benefit)	(4,074)	5,184	4,338
Deferred Income Tax Expense (Benefit):			
Federal	$(19,195)	$ (9,649)	$157,806
State	489	(1,714)	(227)
Federal alternative minimum tax	4,074	(5,504)	(4,111)
Total deferred income tax provision (benefit)	(14,632)	(16,867)	153,468
Total Income Tax Expense (Benefit)	$(18,706)	$ (11,683)	$157,806

As a result of the corporate reorganization in connection with the IPO transaction, the Company established a $132 million provision for deferred income taxes, which was recognized as tax expense from continuing operations in the first quarter of 2014. This $132 million provision, related to our change in tax status, was subsequently adjusted to $95 million during the fourth quarter of 2014. The primary upward adjustments in the effective tax rate above the U.S. statutory rate are the adjustment related to the corporate reorganization noted above along with non-deductible incentive unit compensation.

A reconciliation of tax (benefit) expense based upon the statutory federal income tax rate to the actual income tax (benefit) expense is as follows:

	For the year ended December 31,		
	2016	2015	2014
		(In thousands)	
Income tax expense (benefit) at the federal statutory rate (35%)	$(15,245)	$(10,478)	$56,106
Income tax expense relating to change in tax status	—	—	95,162
State income tax expense (benefit), net of federal tax benefit	318	(1,322)	1,081
Non-deductible expenses	26	69	5,457
Research and development credit	(3,804)	—	—
Other	(1)	48	—
Provision for (benefit from) income taxes	$(18,706)	$(11,683)	$157,806

The components of the Company’s deferred tax assets and liabilities are as follows:

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	For the year ended December 31, 2016	2015
	(In thousands)	
Noncurrent:		
Deferred tax assets		
Net operating loss carryforwards (subject to 20 year expiration)	$88,048	$58,590
Tax credit carryforwards	9,320	9,615
Other	13,185	4,858
Total noncurrent deferred tax assets	110,553	73,063
Deferred tax liabilities		
Oil and natural gas properties and equipment	(433,792)	(409,380)
Other	—	(1,555)
Total noncurrent deferred tax liabilities	(433,792)	(410,935)
Net noncurrent deferred tax liabilities	$(323,239)	$(337,872)

Federal net operating loss carryforwards totaled $260.1 million and $161.3 million at December 31, 2016 and 2015, respectively, and will begin to expire in 2034.

The company recognizes interest accrued related to unrecognized tax benefits in interest expense and penalties in tax expense. The Company has not recognized any interest and penalties. Changes in the balance of unrecognized tax benefits on uncertain positions were as follows:

	Year Ended December 31, 2016	Year Ended December 31, 2015
	(In thousands)	
Unrecognized tax benefits at beginning of period	$ —	$ —
Increase resulting from prior period tax positions	8,483	—
increase resulting from current period tax positions	552	—
Unrecognized tax benefits at the end of period	9,035	—
Less: Effects of temporary items	(5,256)	—
Total unrecognized tax benefits that, if recognized, would impact the effective income tax rate as of the end of the year.	$ 3,779	$ —

NOTE 11—MAJOR CUSTOMERS AND SUPPLIERS

Dependence on Major Customers

The Company believes, due to the competitive nature of goods and services supporting the oil and natural gas industry, plus access to several marketing alternatives, that it is not significantly dependent on any single purchaser. The following purchasers accounted for 10% or greater of total revenues for the periods indicated:

	Percentage of Total Revenues for the Year Ended December 31, 2016	2015	2014
Shell Trading (US) Company	23 %	37 %	31 %
Phillips 66 Company	6 %	22 %	— %

Enterprise Crude Oil LLC	27 %	12 %	24 %
Diamondback E&P, LLC	9 %	13 %	14 %
Permian Transport & Trading	— %	5 %	21 %

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

NOTE 12 - SUPPLEMENTAL DISCLOSURE OF OIL AND NATURAL GAS OPERATIONS (UNAUDITED)

Costs Incurred in Oil and Natural Gas Property Acquisition, Exploration and Development

Costs incurred in the acquisition and development of oil and natural gas assets are presented below for the years ended December 31:

	2016 (2)	2015	2014 (1)
	(In thousands)		
Property acquisition costs:			
Proved	$210,977	$104,532	$581,307
Unproved	1,063,109	351,806	622,210
Exploration costs	1,811	—	16,762
Development costs	293,833	378,910	462,063
Total costs incurred	$1,569,730	$835,248	$1,682,342

(1) Includes non-cash additions in connection with the Company's IPO in 2014 of approximately $842 million.
(2) Includes acquisition costs related to issuance of stock directly to sellers in the SHEP I acquisition in 2016. See Note 3.

Capitalized Oil and Natural Gas Costs

Aggregate capitalized costs related to oil and natural gas production activities with applicable accumulated depreciation, depletion, amortization and impairment are presented below for the years ended December 31:

	2016	2015
	(In thousands)	
Capitalized costs:		
Proved	$2,811,853	$2,197,056
Unproved	1,833,928	878,995
	$4,645,781	$3,076,051
Less accumulated depreciation, depletion, amortization and impairment	(554,419)	(357,524)
Net capitalized costs	$4,091,362	$2,718,527

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Results of Oil and Natural Gas Producing Activities

The results of operations of oil and natural gas producing activities (excluding corporate overhead and interest costs) are presented below for the years ended December 31:

	2016	2015	2014
	(In thousands)		
Revenues:			
Oil and natural gas sales	$353,857	$283,992	$281,925
Costs:			
Lease operating expenses	57,778	53,124	34,704
Production and ad valorem taxes	21,615	19,995	19,758
Depreciation, depletion, and amortization	194,360	154,039	87,844
Asset retirement obligation accretion	472	336	142
Impairments	4,901	34,269	4,344
Exploration	1,093	2,380	3,854
Income tax expense (benefit)	(18,706)	(11,683)	157,806
Results of operations	$92,344	$31,532	$(26,527)

Net Proved Oil and Natural Gas Reserves

The Company's proved oil and natural gas reserves as of December 31, 2016 and December 31, 2014 were prepared by independent third party reserve engineers. The Company's proved oil and natural gas reserves as of December 31, 2015 were audited by independent third party reserve engineers. In accordance with SEC regulations, reserves at December 31, 2016, 2015, and 2014 were estimated using the unweighted arithmetic average first-day-of-the-month price for the preceding 12-month period. Reserve estimates are inherently imprecise and estimates of new discoveries are more imprecise than those of producing oil and natural gas properties. Accordingly, the estimates may change as future information becomes available.

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An analysis of the change in estimated quantities of oil and natural gas reserves, all of which are located within the United States, for the years ended December 31, 2016, 2015, and 2014 is as follows:

	Natural Gas (MMcf)	Oil (MBbls)	NGLs (MBbls)	MBoe
Proved developed and undeveloped reserves:				
As of January 1, 2014	35,803	23,732	6,913	36,613
Revisions of previous estimates	(5,477)	223	2,219	1,529
Extensions, discoveries and other additions	25,229	30,023	5,897	40,125
Purchases of minerals in place	39,841	18,344	7,428	32,412
Production	(2,974)	(3,049)	(718)	(4,263)
As of December 31, 2014	92,422	69,273	21,739	106,416
Revisions of previous estimates	(20,205)	(12,886)	(4,251)	(20,505)
Extensions, discoveries and other additions	55,313	50,375	6,971	66,565
Purchases of minerals in place	10,968	10,178	2,373	14,379
Production	(4,991)	(5,805)	(1,045)	(7,682)
As of December 31, 2015	133,507	111,135	25,787	159,173
Revisions of previous estimates	(30,284)	(14,115)	1,412	(17,750)
Extensions, discoveries and other additions	45,541	46,017	11,631	65,238
Purchases of minerals in place	35,210	29,481	5,551	40,900
Production	(7,188)	(7,790)	(1,685)	(10,673)
As of December 31, 2016	176,786	164,728	42,696	236,888
Proved developed reserves:				
December 31, 2014	35,921	27,716	8,221	41,924
December 31, 2015	56,640	44,128	11,020	64,588
December 31, 2016	76,255	65,025	18,759	96,493
Proved undeveloped reserves:				
December 31, 2014	56,501	41,557	13,518	64,492
December 31, 2015	76,867	67,007	14,767	94,585
December 31, 2016	100,531	99,703	23,937	140,395

The tables above include changes in estimated quantities of oil and natural gas reserves shown in MBbl equivalents ("MBoe") at a rate of six MMcf per one MBbl.

For the year ended December 31, 2016, the Company's negative revisions of previously estimated quantities of 17,750 MBoe is primarily due to the removal of certain vertical PUDs as these locations will be replaced with horizontal wells when drilled in the future. The negative revisions of previously estimated quantities due to pricing were 2,131 MBoe. Extensions, discoveries and other additions of 65,238 MBoe during 2016 result primarily from the drilling of new wells during the year to delineate our acreage position. The purchase of minerals in place of 40,900 MBoe during 2016 includes our acquisition of SHEP I that closed in November 2016, as further described in Note 3.

For the year ended December 31, 2015, the Company's negative revisions of previously estimated quantities of 20,505 MBoe is primarily due to negative revisions due to pricing of 19,641 MBoe. Extensions, discoveries and other additions of 66,565 MBoe during 2015, result primarily from the drilling of new wells during the year and from new proved undeveloped locations added during the year. The purchase of minerals in place of 14,379 MBoe during 2015 were related to several acquisitions during the year, as described in Note 3.

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For the year ended December 31, 2014, the Company's positive revisions of previously estimated quantities of 1,529 MBoe is primarily due to the change in estimates and type curves, which more than offset negative revisions due to pricing of 4,053 MBoe. Extensions, discoveries and other additions of 40,125 MBoe during 2014, result primarily from the drilling of new wells during the year and from new proved undeveloped locations added during the year. The purchase of minerals in place of 32,412 MBoe during 2014 were related to the Collins and Wallace contributions in connection with our IPO, and the Glasscock County acquisition.

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, 2016, 2015, and 2014 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 and natural gas reserves is as follows at December 31:

	2016	2015	2014
	(In thousands)		
Future cash inflows	$7,433,650	$5,964,332	$7,015,504
Future production costs	(2,352,287)	(1,855,044)	(2,025,302)
Future development costs	(1,315,835)	(1,187,244)	(1,182,981)
Future income tax expense	(659,105)	(699,070)	(1,154,808)
Future net cash flows	3,106,423	2,222,974	2,652,413
10% discount for estimated timing of cash flows	(1,913,027)	(1,426,958)	(1,776,282)
Standardized measure of discounted future net cash flows	$1,193,396	$796,016	$876,131

In the foregoing determination of future cash inflows, sales prices used for gas and oil for December 31, 2016, 2015 and 2014 were estimated using the average price during the 12-month period, determined as the unweighted arithmetic average of the first-day-of-the-month price for each month. 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 the 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.

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Changes in the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves are as follows:

	2016	2015	2014
	(In thousands)		
Standardized measure of discounted future net cash flows, beginning of year	$796,016	$876,131	$550,715
Changes in the year resulting from:			
Sales, less production costs	(279,603)	(210,874)	(223,608)
Revisions of previous quantity estimates	(142,956)	(192,081)	20,892
Extensions, discoveries and other additions	390,752	440,744	646,855
Net change in prices and production costs	(251,166)	(537,613)	(74,081)
Changes in estimated future development costs	156,162	14,480	(7,858)
Previously estimated development costs incurred during the period	68,238	107,829	44,925
Purchases of minerals in place	244,977	95,207	366,106
Accretion of discount	86,109	131,764	55,072
Net change in income taxes	15,059	164,377	(441,506)
Timing differences and other	109,808	(93,948)	(61,381)
Standardized measure of discounted future net cash flows, end of year	$1,193,396	$796,016	$876,131

Estimates of economically recoverable oil and natural gas reserves and of future net revenues are based upon a number of variable factors and assumptions, all of which are to some degree subjective and may vary considerably from actual results. Therefore, actual production, revenues, development and operating expenditures may not occur as estimated. The reserve data are estimates only, are subject to many uncertainties and are based on data gained from production histories and on assumptions as to geologic formations and other matters. Actual quantities of oil and natural gas may differ materially from the amounts estimated.

NOTE 13 - QUARTERLY FINANCIAL DATA (Unaudited)

The Company’s unaudited quarterly financial data for 2016 and 2015 is summarized below.

	2016			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$55,815	$81,485	$93,621	$122,934
Operating income (loss)	(14,342)	2,295	13,248	29,892
Income tax benefit	9,298	4,438	3,507	1,464
Net income (loss)	$(17,416)	$(9,801)	$985	$1,381
Earnings (loss) per share:				
Basic and diluted	$(0.17)	$(0.10)	$0.01	$0.01

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	2015			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$51,375	$78,465	$80,644	$73,508
Operating income (loss)	(4,568)	10,912	7,443	(21,564)
Income tax (expense) benefit	330	6,001	(4,953)	10,307
Net income (loss)	$(1,024)	$(5,453)	$8,974	$(20,751)
Earnings (loss) per share:				
Basic and diluted	$(0.01)	$(0.07)	$0.10	$(0.21)

In the third and the fourth quarters of 2015, impairment expense was $4.2 million and $30.0 million, respectively. In the first, second, third, and fourth quarters of 2016, impairment expense was $0.2 million, $3.2 million, $1.0 million, and $0.6, respectively.

In the fourth quarter of 2016, expensed acquisition costs associated with the Silver Hill acquisitions were $6.4 million.

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EXHIBIT INDEX

Exhibit No.	Description
3.1	Amended and Restated Certificate of Incorporation of RSP Permian, Inc. (incorporated by reference to Exhibit 3.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on January 29, 2014).
3.2	Amended and Restated Bylaws of RSP Permian, Inc. (incorporated by reference to Exhibit 3.1 of the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the Commission on December 21, 2016).
4.1	Specimen Common Stock Certificate (incorporated by reference to Exhibit 4.1 of the Company's Registration Statement on Form S-1/A (File No. 333-192268) filed with the Commission on January 13, 2014).
4.2	Registration Rights Agreement, dated as of January 23, 2014, among the Company, RSP Permian Holdco, L.L.C., Ted Collins, Jr., Wallace Family Partnership, LP, ACTOIL, LLC, Rising Star Energy Development Co., L.L.C. and Pecos Energy Partners, L.P. (incorporated by reference to Exhibit 4.2 of the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the Commission on January 29, 2014).
4.3	Stockholders’ Agreement, dated as of January 23, 2014, among the Company, RSP Permian Holdco, L.L.C., Ted Collins, Jr., Wallace Family Partnership, LP, Rising Star Energy Development Co., L.L.C and Pecos Energy Partners, L.P. (incorporated by reference to Exhibit 4.1 of the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the Commission on January 29, 2014).
4.4	Indenture, dated as of September 26, 2014, by and among the Company, RSP Permian, L.L.C. and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on October 2, 2014).
4.5	Form of Senior Note due 2022 (incorporated by reference to Exhibit 4.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on October 2, 2014).
4.6	Registration Rights Agreement, dated as of August 10, 2015, by and among the Company, RSP Permian, L.L.C. and Goldman, Sachs, & Co. (incorporated by reference to Exhibit 4.2 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on August 12, 2015).
4.7(a)	Registration Rights Agreement, dated as of November 28, 2016, by and between the Company and Silver Hill Energy Partners Holdings, LLC.
4.8(a)	Stockholder’s Agreement, dated as of November 28, 2016, by and between the Company and Kayne Anderson Capital Advisors, LP.
4.9	Indenture, dated as of December 27, 2016, by and among the Company, RSP Permian, L.L.C., Silver Hill Energy Partners, LLC and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 of the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the Commission on December 27, 2016).
4.10	Form of Senior Note due 2025 (incorporated by reference to Exhibit 4.1 of the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the Commission on December 27, 2016).
4.11	Registration Rights Agreement, dated as of December 27, 2016, by and among the Company, RSP Permian, L.L.C., Silver Hill Energy Partners, LLC, and Barclays Capital Inc. and RBC Capital Markets, LLC, as representatives of the several initial purchasers (incorporated by reference to Exhibit 4.2 of the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the Commission on December 27, 2016).
10.1	Amended and Restated Credit Agreement, dated September 10, 2013, by and among RSP Permian, L.L.C., as borrower, Comerica Bank, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company's Registration Statement on Form S-1 (File No. 333-192268) filed with the Commission on November 12, 2013).
10.2	First Amendment to Amended and Restated Credit Agreement, dated June 9, 2014, by and among RSP Permian, L.L.C., as borrower, Comerica Bank, as administrative agent, and the lenders party thereto

	(incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on June 9, 2014).
10.3	Second Amendment to Amended and Restated Credit Agreement, dated August 29, 2014, by and among RSP Permian, L.L.C., as borrower, Comerica Bank, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on September 4, 2014).
10.4	Third Amendment to Amended and Restated Credit Agreement, dated September 12, 2014, by and among RSP Permian, L.L.C., as borrower, Comerica Bank, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on September 18, 2014).
10.5	Fourth Amendment to Amended and Restated Credit Agreement, dated August 24, 2015, by and among RSP Permian, L.L.C., as borrower, Comerica Bank, as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on August 25, 2015).
10.6(c)	2014 Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 of the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the Commission on January 22, 2014).
10.7(c)	Form of Restricted Stock Grant and Award Agreement (Performance Vesting) (incorporated by reference to Exhibit 10.1 of the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the Commission on April 16, 2014).
10.8(c)	Form of Restricted Stock Grant and Award Agreement (incorporated by reference to Exhibit 10.3 of the Company’s Quarterly Report on Form 10-Q (File No. 001-36264) filed with the Commission on May 15, 2014).
10.9(c)	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.4 to the Company’s Registration Statement on Form S-1/A (File No. 333-192268) filed with the Commission on January 2, 2014).
10.10(c)	Executive Change in Control and Severance Benefit Plan of RSP Permian, Inc. (incorporated by reference to Exhibit 10.6 to the Company's Registration Statement on Form S-1/A (File No. 333-196388) filed with the Commission on July 25, 2014).
10.11	Purchase and Sale Agreement, dated July 22, 2014, by and among Adventure Exploration Partners II, LLC, Alpine Oil Company, JM Cox Resources, LP and D.R.E. Interests, LLC, as sellers, and RSP Permian, L.L.C., as purchaser (incorporated by reference to Exhibit 2.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on July 25, 2014).
10.12	Purchase and Sale Agreement, dated November 17, 2015, by and between Wolfberry Partners Resources LLC, as seller, and RSP Permian, L.L.C., as purchaser (incorporated by reference to Exhibit 2.1 of the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the Commission on November 23, 2015).

10.13	Surface Use and Settlement Agreement, dated November 17, 2015, by and between Collins & Wallace Holdings, LLC and RSP Permian, L.L.C. (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on November 23, 2015).
10.14*	Membership Interest Purchase and Sale Agreement, dated as of October 13, 2016, by and among Silver Hill Energy Partners Holdings, LLC, Silver Hill Energy Partners, LLC, RSP Permian, L.L.C. and the Company (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on October 13, 2016).
10.15*	Membership Interest Purchase and Sale Agreement, dated as of October 13, 2016, by and among Silver Hill Energy Partners II, LLC, Silver Hill E&P II, LLC, RSP Permian, L.L.C. and the Company (incorporated by reference to Exhibit 10.2 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on October 13, 2016).
10.16	Purchase Agreement dated as of December 12, 2016, by and among the Company, the Guarantors and Barclays Capital Inc. and RBC Capital Markets, LLC, as representatives of the several initial purchasers (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on December 13, 2016).
10.17	Credit Agreement, dated as of December 19, 2016, among the Company, RSP Permian, L.L.C., JPMorgan Chase Bank, N.A., as administrative agent, and the lenders party thereto (incorporated by reference to Exhibit 10.1 of the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on December 21, 2016).
12.1	Computation of Ratio of Earnings to Fixed Charges.
21.1(a)	Subsidiaries of RSP Permian, Inc.
23.1(a)	Consent of Grant Thornton LLP.
23.2(a)	Consent of Netherland, Sewell & Associates, Inc.
31.1(a)	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, Rule 13a-14(a)/15d-14(a), by Chief Executive Officer.
31.2(a)	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002, Rule 13a-14(a)/15d-14(a), by Chief Financial Officer.
32.1(b)	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Chief Executive Officer.
32.2(b)	Certification pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, by Chief Financial Officer.
99.1(a)	Netherland, Sewell & Associates, Inc. Summary of Reserves at December 31, 2016 (RSP Permian, Inc.).
99.2(a)	Netherland, Sewell & Associates, Inc. Summary of Reserves at December 31, 2016 (Silver Hill II Acquisition Interest).
101.INS(a)	XBRL Instance Document.
101.SCH(a)	XBRL Taxonomy Extension Schema Document.
101.CAL(a)	XBRL Taxonomy Extension Calculation Linkbase Document.
101.DEF(a)	XBRL Taxonomy Extension Definition Linkbase Document.
101.LAB(a)	XBRL Taxonomy Extension Label Linkbase Document.
101.PRE(a)	XBRL Taxonomy Extension Presentation Linkbase Document.