RSP Permian, Inc.
Form 10-K
March 17, 2015
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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, 2014

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 State or other jurisdiction of incorporation or organization	90-1022997 (I.R.S. Employer Identification Number)
3141 Hood Street, Suite 500 Dallas, Texas (Address of principal executive offices)	75219 (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	o	Accelerated filer o
Non-accelerated filer	x (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, 2014, was approximately $1,097,011,350. 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 78,267,452 shares of common stock outstanding at March 16, 2015.

DOCUMENTS INCORPORATED BY REFERENCE:
(1) Portions of the Definitive Proxy Statement for the Company's Annual Meeting of Shareholders to be held during May 2015 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.

"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.

"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.

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"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.

“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.

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"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, unless specific circumstances justify a longer time.

"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.

"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.

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“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 transactions, RSP Permian, L.L.C. and, after the IPO Transactions (as defined in “Part I, Item 1. Business-History and Formation”), 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.

Information presented in this Report on a pro forma basis gives effect to the completion of the corporate reorganization and acquisitions in connection with our initial public offering completed in January 2014, each as described under “Part II, Item 2. Management’s Discussion and Analysis of Financial Condition and Results of Operation—The IPO and Related Transactions.”

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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 statemen the Company's business strategy and plans, constitute “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995. 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 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 (the "Company"), is an independent oil and natural gas company focused on the acquisition, exploration, development and production of unconventional oil and associated liquids-rich natural gas reserves in the Permian Basin 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, a sub-basin of the Permian Basin, primarily in the adjacent counties of Midland, Martin, Andrews, Dawson, Ector and Glasscock. 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, and its website is www.rsppermian.com. Information on the Company's website is not incorporated by reference into this Report.

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"). See "Part II. Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - The IPO and Related Transactions" for more information regarding 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. 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 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, 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, we have participated in the completion of 92 horizontal wells (45 of which we operate) as of December 31, 2014. Of these operated horizontal wells, 3 are Wolfcamp A wells, 17 are Wolfcamp B wells, 2 are Wolfcamp D wells, 9 are Middle Spraberry wells, 14 are Lower Spraberry wells. We believe that our properties provide horizontal opportunities in several other intervals, such as the Jo Mill, Dean, Strawn, Atoka, Mississippian and Devonian formations. We target the multiple oil and natural gas producing stratigraphic horizons, or stacked pay zones, on our properties.

We believe our vertical drilling program is a strong complement to our horizontal drilling program, and plan to continue to drill vertical Wolfberry wells during times when prevailing commodity prices and service costs enable us to generate attractive returns. In areas where we drill horizontal wells, vertical drilling, in concert with horizontal drilling, may allow us to optimize

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total hydrocarbon recovery on our acreage, while continuing to provide attractive returns on a standalone basis. In addition, on certain sections of our acreage, vertical drilling may provide the most attractive returns. Further, the combination of horizontal and vertical drilling enables us to hold our acreage through our continuous development program.

During 2014, we increased our operated horizontal rigs to four and our operated vertical rigs to four before releasing two vertical rigs near the end of the year. We added a fifth horizontal rig in early 2015. Our current operating budget for 2015 anticipates us reducing our operated rig count to three horizontal rigs and no vertical rigs by the end of 2015.

During 2014, we spent approximately $442 million on drilling and completion activities, $42 million of infrastructure and other, and approximately $362 million of acquisitions and additions to leasehold. Of the total capital spent, approximately $55 million was on non-operated properties and approximately $62 million was on drilling wells the Company expects to complete in 2015.

Our board of directors has approved a capital budget for drilling, completion, and infrastructure for 2015 of approximately $400 to $450 million. We intend to allocate our 2015 capital budget approximately as follows:

•$380 to $420 million for drilling and completion activities; approximately 15% of which is non-operated drilling and completion activities; and
•$20 to $30 million for infrastructure and other.

For the year ended December 31, 2014, our average pro forma net daily production was 11,868 Boe/d (approximately 72% oil, 11% natural gas and 17% NGLs), of which 42% was from horizontal well production and 58% was from vertical well production. As of December 31, 2014, we operated and produced from 41 horizontal and 306 vertical wells and were the operator of approximately 95% of our net acreage.

As of December 31, 2014, our estimated proved oil and natural gas reserves were 106.4 MMBoe based on a reserve report prepared 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 342 vertical well locations and 109 horizontal well locations. As of December 31, 2014, total proved reserves were approximately 65% oil, 15% natural gas and 20% NGLs.

The following table provides summary pro forma information regarding our proved reserves as of December 31, 2014 and production for the year ended December 31, 2014.

	Estimated Total Proved Reserves							Average Net
	Oil (MMBbls)	Natural Gas (Bcf)	NGLs (MMBbls)	Total (MMBoe)	% Oil	% Liquids(1)	% Developed	Production (Boe/d)
Midland Basin	69.3	92.4	21.7	106.4	65	85	39	11,868

(1) Includes both oil and NGLs.

We regularly seek to acquire properties that complement our operations, provide exploration and development opportunities and potentially provide superior returns on investment. During the first quarter of 2014, we acquired additional acreage that we believe is prospective for horizontal development located in Martin, Glasscock and Dawson Counties in Texas for an aggregate purchase price of approximately $79 million in three separate transactions, with approximately $69 million recorded as proved oil and natural gas properties. In August 2014, in separate transactions with multiple sellers, we acquired certain undeveloped acreage and oil and natural gas producing properties located in

Glasscock County, adding another primary operating area in the core of the Northern Midland Basin, for an aggregate purchase price of $257 million in cash (subject to certain post-closing adjustments), the substantial majority of which was to acquire undeveloped acreage.

Competition and Markets

General

We are the operator of approximately 95% 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

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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 a five year oil purchase agreement with Shell Trading (US) Company ("Shell Trading"). 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, 2014, four purchasers accounted for more than 10% of our revenue: Shell Trading Company (US) (31%), Enterprise Crude Oil LLC (24%), Permian Transport & Trading (21%) and Diamondback E&P LLC (14%). For the year ended December 31, 2013, four purchasers accounted for more than 10% of our revenue: Shell Trading Company (US) (40%), Enterprise Crude Oil LLC (14%), Plains Marketing, L.P. (13%) and Diamondback E&P LLC (11%). For the year ended December 31, 2012, two purchasers accounted for more than 10% of our revenue: Plains Marketing, L.P. (76%) and Coronado Midstream, LLC (11%). 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. Our larger or more integrated competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing oil and natural gas properties.

There is also competition between oil and natural gas producers and other industries producing energy and fuel. Furthermore, competitive conditions may be substantially affected by various forms of energy legislation and/or regulation considered from time to time by the governments of the United States and the jurisdictions in which we operate. It is not possible to predict the nature of any such legislation or regulation which may ultimately be adopted or its effects upon our future operations. Such laws and regulations may substantially increase the costs of 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, oil and natural gas. Demand for oil and natural gas is typically higher in the fourth and first quarters resulting in higher prices. Due to these seasonal fluctuations, results of operations for individual quarterly periods may not be indicative of the results that may be realized on an annual basis.

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

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, the 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.

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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.

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.

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 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

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navigable waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers. 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 require, 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. This rule could require a number of modifications to 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.

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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 January 2015, the Obama Administration announced that the EPA is expected to propose in the summer of 2015 and finalize in 2016 new regulations that will set methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities as part of the Administration's efforts to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025.

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 May 2013, the Bureau of Land Management (the "BLM") of the U.S. Department of the Interior published a revised proposed rule that would impose 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 is developing effluent limitation guidelines that may impose federal pre treatment standards on all oil and natural gas operators transporting wastewater associated with hydraulic fracturing activities to publicly owned treatment works for disposal. The EPA plans to propose such standards sometime in 2015.

Certain governmental reviews have been conducted or are underway that focus on the potential environmental impacts of hydraulic fracturing. The White House Council on Environmental Quality is coordinating an administration wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on water resources and expects to make the final report available for public comment and peer review sometime in 2015. 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 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. 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

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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. For example, in March 2014, the FWS listed the lesser prairie chicken as a threatened species under the ESA. 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 2014, nor do we anticipate that such expenditures will be material in 2015.

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

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

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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, 2014, we had 79 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.

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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 and have recently declined significantly. If oil, NGL and natural gas prices do not improve or decline further, our business, financial condition, results of operations and ability to meet our capital expenditure obligations and financial commitments may be materially and adversely affected.
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. On February 10, 2015, the WTI posted price for crude oil was $50.06 per barrel and the Henry Hub spot market price of natural gas was $2.67 per MMBtu, representing decreases of 53% and 57%, respectively, from the high of $106.91 per barrel of oil and $6.15 per MMBtu for natural gas during 2014. Likewise, NGLs have suffered significant recent declines in realized prices. If the prices of oil, NGL and natural gas decline further, our operations, financial condition and level of expenditures for the development of our oil, NGL and natural gas reserves may be materially and adversely affected. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control and include the following:

- worldwide and regional economic conditions affecting the global supply and demand for oil, NGLs and natural gas;
- the ability of members of the Organization of the Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- 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;
- the level of global exploration and production;
- the level of global inventories;
- prevailing prices on local price indexes in the areas in which we operate;
- the proximity, capacity, cost and availability of gathering and transportation facilities;
- localized and global supply and demand fundamentals and transportation availability;
- the cost of exploring for, developing, producing and transporting reserves;
- weather conditions and other natural disasters;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels;
- expectations about future commodity prices; and
- domestic, local and foreign governmental regulation and taxes.

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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, a substantial or extended decline in commodity prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

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

We enter into derivative instrument contracts from time to time for a portion of our production. As of December 31, 2014, we had entered into hedging contracts through December 31, 2015 covering a total of approximately 2,457 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, 2014, the estimated fair value of our commodity derivative contracts was a net asset of approximately $75.7 million. Any default by the counterparties, to these derivative contracts when they become due, would 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.

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 2015 capital budget for drilling, completion, recompletion and infrastructure is currently estimated to be approximately $400 million to $450 million. Our capital budget excludes acquisitions. We expect to fund 2015 capital expenditures with cash generated by operations, borrowings under our revolving credit facility, 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;

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- 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;
- 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.

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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.

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.

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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 62,448 gross (47,014 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, 2014, we had identified 2,064 horizontal drilling locations on our acreage based on approximately 500 to over 1,000 foot spacing between wells in the same horizontal zone. Additionally, based on our evaluation of applicable geologic and engineering data as of December 31, 2014, we had 403 identified vertical drilling locations on 40 acre spacing and an additional 803 identified vertical drilling locations based on 20 acre downspacing. As a result of the limitations described above, we may be unable to drill many of our drilling locations. In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. See "-Our 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 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, drought conditions have persisted in Texas over the past several years, which have led governmental authorities to restrict the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supplies. If we are unable to obtain water 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.

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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, 2014, 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.

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.

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, 2014, 61% 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 writedown 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

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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.

We normally sell our production to a relatively small number of customers, as is customary in the exploration, development and production business. For the year ended December 31, 2014, four purchasers each accounted for more than 10% of our revenue: Diamondback E&P, LLC (14%), Shell Trading (US) Company (31%), Enterprise Crude Oil LLC (24%) and Permian Transport & Trading (21%). For the year ended December 31, 2013, four purchasers each accounted for more than 10% of our revenue: Plains Marketing, L.P. (13%), Shell Trading (US) Company (40%), Enterprise Crude Oil LLC (14%) and Diamondback E&P LLC (11%). The loss or significant reduction in commitment of any of these purchasers could materially and adversely affect our revenues in the short term.

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 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

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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;
- 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

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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, and any inability to do so may disrupt our business and hinder our ability to grow.

In the future we may make acquisitions of assets or businesses that complement or expand our current business. However, there is no guarantee we will be able to identify attractive acquisition opportunities. In the event we are able to identify attractive acquisition opportunities, we may be unable to complete the acquisition, or do so on commercially acceptable terms. Competition for acquisitions may also increase the cost of, or cause us to refrain from, 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 and the indenture governing our 6.625% senior notes due 2022 (the "notes") impose certain limitations on our ability to enter into mergers or combination transactions. Our revolving credit facility and the indenture also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses.

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

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

The unavailability or high cost 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. 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

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drilled. 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, the Obama Administration is expected to release a series of new regulations on the oil and gas industry in 2016, including federal standards limiting methane emissions. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Substantial limitations on GHG emissions could adversely affect demand for the oil and natural gas we produce. 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.

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 May 2013, the BLM of the U.S. Department of the Interior published a revised proposed rule that would impose requirements for hydraulic fracturing activities on federal

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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 is developing effluent limitation guidelines that may impose federal pre treatment standards on all oil and natural gas operators transporting wastewater associated with hydraulic fracturing activities to publicly owned treatment works for disposal. The EPA plans to propose such standards sometime in 2015.

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. The EPA received numerous requests for reconsideration of these rules and court challenges were also filed. The EPA intends to issue revised rules that are likely responsive to some of these requests. For example, in September 2013 the EPA published an amendment extending compliance dates for certain storage vessels. At this point, we cannot predict the final regulatory requirements or the cost to comply with such requirements with any certainty.

In addition, certain governmental reviews have been conducted or are underway that focus on the potential environmental impacts of hydraulic fracturing. The White House Council on Environmental Quality is coordinating an administration wide review of hydraulic fracturing practices. The EPA has also commenced a study of the potential environmental effects of hydraulic fracturing on water resources and expects to make the final report available for public comment and peer review sometime in 2015. 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. 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.

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

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

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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.

Our business is difficult to evaluate because we have a limited operating history.

RSP LLC was formed in October 2010 by our management team and an affiliate of Natural Gas Partners, a family of energy-focused private equity investment funds. As a result, there is only limited historical financial and operating information available upon which to base your evaluation of our performance.

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. 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
- 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.

The Fiscal Year 2016 Budget proposed by the President recommends the elimination of certain key U.S. federal income tax incentives currently available to oil and natural gas exploration and production companies, and legislation has been introduced in Congress that would implement many of these proposals. Such 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 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.

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

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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.

If we fail to develop or maintain an effective system of internal controls, we may not be able to accurately report our financial results or prevent fraud.

Effective internal controls are necessary for us to provide reliable financial reports and prevent fraud. If we cannot provide reliable financial reports or prevent fraud, our reputation and operating results may be harmed. We cannot be certain that our efforts to develop and maintain our internal controls will be successful, that we will be able to maintain adequate controls over our financial processes and reporting in the future. Any failure to develop or maintain effective internal controls, or difficulties encountered in implementing or improving our internal controls, could harm our operating results.

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.

Four of our largest stockholders, Production Opportunities II. L.P., Collins, Wallace LP and ACTOIL (our "Principal Investors"), collectively hold approximately 46% of our common stock as of December 31, 2014, and their interests may conflict with yours. 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.

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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 $500 million, with lender commitments of $1 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 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 indenture governing the 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 $500 million. Our next scheduled borrowing base redetermination is expected to occur on May 1, 2015. 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, 2014, we had $500 million of notes outstanding, $0.4 million of letters of credit outstanding under our revolving credit facility, and $499.6 million of borrowing capacity under our revolving credit facility. Our level of indebtedness could affect our operations in several ways, including the following:

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- 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;
- 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 indenture governing the notes, we may incur substantial additional indebtedness (including secured indebtedness) in the future. Although our credit facility and indenture governing the 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.

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Our revolving credit facility and the indenture governing the 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 indenture governing the 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 indenture governing the 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;
- 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.

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ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Our properties include working interests in approximately 62,448 surface acres located in the Permian Basin in the Texas counties of Midland, Martin, Andrews, Dawson, Ector, and Glasscock. The following table summarizes our surface acreage by county as of December 31, 2014.

	Gross	Net
County:		
Andrews	4,780	4,522
Dawson	14,171	12,152
Ector	4,830	4,676
Glasscock	6,831	6,643
Martin	12,906	6,767
Midland	18,168	11,568
Upton	762	686
Total	62,448	47,014

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. The Midland Basin is characterized by an extensive operating history, a favorable operating environment, mature infrastructure, long reserve life, multiple producing horizons, enhanced recovery potential and a large number of operators. The Midland Basin, a sub-basin of the Permian Basin, has been one of the most prolific oil-producing regions in Texas. The first commercial oil well drilled in the Midland Basin was completed in 1921, and the large resource potential of the Spraberry Trend was discovered in the 1940s. The Wolfcamp formation has a similarly long operating history, as drillers aiming for deeper conventional targets during the 1950s occasionally intersected carbonate formations and debris flows with good reservoir properties. Industry operators often refer to the combined Spraberry and Wolfcamp formations in terms of vertical development as the “Wolfberry” play, but recent advances in geologic understanding and production technology have highlighted the resource potential of the region’s unconventional reservoirs, located in mudrock-dominated intervals 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 Midland Basin and the entire Permian Basin has shown a growing trend towards horizontal and directional drilling over vertical drilling. In January 2012, there were approximately 354 vertical rigs operating in the Permian Basin and 123 horizontal/directional rigs. In late 2013, the number of horizontal/directional rigs exceeded the number of vertical rigs operating in the Permian Basin for the first time.

The vast majority of our acreage is located on large, contiguous acreage blocks in the core of the Midland Basin, primarily in the contiguous Texas counties of Midland, Martin, Andrews, Dawson, Ector, and Glasscock. 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.

Our contiguous acreage positions allow us to 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 positions and the flexibility it provides allow us to target multiple horizontal zones underneath our surface acreage, providing us with total Effective Horizontal Acreage of approximately 187,598 net acres in the Midland Basin. The following table provides a summary of our Effective Horizontal Acreage, which we believe more accurately conveys our horizontal drilling opportunities in our target zones.

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	Effective Horizontal Acreage(1)	
	Gross	Net
Target Horizontal Zones:		
Middle Spraberry	55,256	40,200
Lower Spraberry	60,996	45,864
Wolfcamp A	39,651	27,383
Wolfcamp B	56,403	41,958
Wolfcamp D (Cline)	45,176	32,193
Total	257,482	187,598

(1) Our calculation of our Effective Horizontal Acreage is an inexact estimate. We cannot assure you that any amount of our Effective Horizontal Acreage listed above in each of our target horizontal zones is prospective for that zone. Additionally, we cannot ascertain what portion of our Effective Horizontal Acreage will ever be drilled. See "Item 1A. Risk Factors—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 primary focus shifted in late 2012 to drilling higher rate of return horizontal wells targeting the Middle Spraberry, Lower Spraberry, Wolfcamp A, Wolfcamp B and Wolfcamp D (Cline) formations. In addition, we believe our properties present additional horizontal drilling opportunities from several other stacked pay zones such as the Clearfork, Jo Mill, Dean, Strawn, Atoka, Mississippian and Devonian formations.

Netherland Sewell, our independent petroleum engineering firm, has estimated proved reserves, net to our interest, in our properties, as of December 31, 2014, were approximately 106.4 MMBoe, of which 39% were classified as PDP. The proved reserves are generally characterized as long-lived, with predictable production profiles.

Production Status. For the year ended December 31, 2014, our average net daily production on a pro forma basis was 11,868 Boe/d (approximately 72% oil, 17% NGLs and 11% natural gas), of which 42% was from horizontal well production and 58% was from vertical well production. During 2013, our average net daily production was 7,293 Boe/d (approximately 70% oil, 16% NGLs and 14% natural gas), of which 15% was from horizontal well production and 85% was from vertical well production. As of December 31, 2014, we operated and produced from 41 horizontal and 306 vertical wells and were the operator of approximately 95% 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.

Recent Activity. A total of 102 gross (53 net) wells were drilled on our acreage during 2013, and during 2014, 149 gross (86 net) wells were drilled on our acreage.

As of December 31, 2014, we had identified 2,064 horizontal drilling locations in multiple horizons across our acreage. In addition, based on our evaluation of applicable geologic and engineering data, as of December 31, 2014, we had 403 identified vertical drilling locations on 40-acre spacing and an additional 803 identified vertical drilling locations based on 20-acre downspacing. 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.

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Oil and Natural Gas Data

Proved Reserves

Evaluation and Review of Proved Reserves. Our proved reserve estimates as of December 31, 2014 were prepared by Netherland Sewell, our independent petroleum engineers. The technical persons responsible for preparing our proved reserve estimates meet the requirements with regard to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. 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 the independent petroleum engineering firm's proved reserve report as of December 31, 2014 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. Tamara Pollard, our Executive Vice President of Planning and Reserves, is primarily responsible for overseeing the preparation of all of our reserve estimates. Ms. Pollard is a petroleum engineer with over 25 years of reservoir and operations experience, and our geoscience staff has an average of approximately 30 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 Ms. Pollard or under her 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 Executive Vice President of Planning and Reserves to our Chief Executive 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, 2014 and 2013 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and natural gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil and natural gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into four broad categories or methods: (i) production performance-based methods; (ii) material balance-based methods; (iii) volumetric-based methods; and (iv) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserves for PDP wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to similar production, both of which are considered to provide a 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

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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 Reserves. The following table presents our estimated net proved oil and natural gas reserves as of December 31, 2014 and our pro forma net proved oil and natural gas reserves, after giving effect to the IPO Transactions as if the IPO Transactions had occurred on January 1, 2013, as of December 31, 2013, 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. A copy of the reserve report as December 31, 2014 prepared by Netherland Sewell with respect to our properties is included as an exhibit to this Report.

	At December 31, 2014	Pro Forma At December 31, 2013
Proved developed reserves:		
Oil (MBbls)	27,716	13,921
Natural gas (MMcf)	35,921	21,008
NGLs (MBbls)	8,221	3,965
Total (MBoe)	41,924	21,387
Proved undeveloped reserves:		
Oil (MBbls)	41,557	21,011
Natural gas (MMcf)	56,501	31,665
NGLs (MBbls)	13,518	6,207
Total (MBoe)	64,492	32,496
Total proved reserves:		
Oil (MBbls)	69,273	34,932
Natural gas (MMcf)	92,422	52,673
NGLs (MBbls)	21,739	10,172
Total (MBoe)	106,416	53,883

On a pro forma basis, the changes from December 31, 2013 estimated proved reserves to December 31, 2014 estimated proved reserves reflect production during this period of approximately 4,332 MBoe, net positive revisions of approximately 1,529 MBoe, additions due to acquisitions of 15,211 MBoe, and additions of approximately 40,125 MBoe attributable to extensions resulting from strategic drilling of wells by us to delineate our acreage position.

Reserve engineering is and must be recognized as a subjective process of estimating volumes of economically recoverable oil and natural gas that cannot be measured in an exact manner. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation. As a result, the estimates of different engineers often vary. In addition, the results of drilling, testing and production may justify revisions of such estimates. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered. Estimates of economically recoverable oil and natural gas and of future net revenues are based on a number of variables and assumptions, all of which may vary from actual results, including geologic interpretation, prices and future production rates and costs. Please read “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 report as of December 31, 2014, which is included as an exhibit to this Report.

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PUDs

Year Ended December 31, 2014

As of December 31, 2014, our PUDs totaled 41,557 MBbls of oil, 13,518 MBbls of NGLs and 56,501 MMcf of natural gas, for a total of 64,492 MBoe. PUDs will be converted from undeveloped to developed as the applicable wells begin production. Changes in PUDs that occurred during 2014 were primarily due to:

•additions of approximately 27,827 MBoe attributable to extensions resulting from strategic drilling of wells by us to delineate our acreage position;

•additions of approximately 10,299 MBoe attributable to acquisitions; and

•the conversion of approximately 5,378 MBoe attributable to PUDs into proved developed reserves.

During the year ended December 31, 2014, we spent $76.4 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, 2014, 1% of our total proved reserves were classified as proved developed non-producing.

Year Ended December 31, 2013 (Pro Forma)

As of December 31, 2013, our PUDs totaled 21,011 MBbls of oil, 6,207 MBbls of NGLs and 31,665 MMcf of natural gas, for a total of 32,496 MBoe. PUDs will be converted from undeveloped to developed as the applicable wells begin production. Changes in PUDs that occurred during 2013 were primarily due to:

•additions of approximately 9,747 MBoe attributable to extensions resulting from strategic drilling of wells by us to delineate our acreage position; and

•the conversion of approximately 5,599 MBoe attributable to PUDs into proved developed reserves.

During the year ended December 31, 2013, we spent $108.9 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, 2013, 1% of our total proved reserves were classified as proved developed non-producing.

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Oil and Natural Gas Production Prices and Costs

Production and Price History

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

	RSP Permian, Inc. (1)		RSP Permian, Inc. Pro Forma (2)	
	Years ended December 31,			
	2014	2013	2014	2013
Production data:				
Oil (MBbls)	3,049	1,167	3,099	1,867
Natural gas (MMcf)	2,974	1,597	3,023	2,287
NGLs (MBbls)	718	250	729	414
Total (MBoe)	4,263	1,683	4,332	2,662
Average net daily production (Boe/d)	11,679	4,611	11,868	7,293
Average prices before effects of hedges(1)(2):				
Oil (per Bbl)	$83.10	$94.55	$83.20	$95.01
Natural gas (per Mcf)	3.55	3.37	3.56	3.34
NGLs (per Bbl)	25.04	29.26	25.13	28.16
Total (per Boe)	$66.13	$73.11	$66.23	$73.89
Average realized prices after effects of hedges(3)(4):				
Oil (per Bbl)	$85.01	$94.17	$85.08	$94.79
Natural gas (per Mcf)	3.59	3.37	3.60	3.34
NGLs (per Bbl)	25.04	29.26	25.13	28.16
Total (per Boe)	$67.53	$72.84	$67.60	$73.73
Average costs (per Boe):				
Lease operating expenses (excluding gathering and transportation)	$7.49	$7.79	$7.52	$7.92
Gathering and transportation	0.65	0.60	0.65	0.60
Production and ad valorem taxes	4.63	4.95	4.62	4.97
Depreciation, depletion and amortization	20.61	28.02	21.12	30.24
Components of general and administrative expense:				
General and administrative - cash component (5)	$4.25	$2.29	$3.44	$1.40
General and administrative - (non IPO stock comp) (6)	0.64	—	0.63	—
General and administrative - (IPO stock comp) (7)	4.11	—	—	—
Total general and administrative (8)	9.00	2.29	4.07	1.40

(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 (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) The IPO bonus amounts recognized in the 2014 actual results increased the general and administrative - cash component per Boe from 2013 actual amounts. See the discussion of general and administrative expenses in "Part I, Item 2. Management's Discussion and Analysis of Financial Condition-Results of Operations.

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(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.
(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 9-Equity Based Compensation of Notes to Consolidated Financial Statements included in “Part II, Item 8. Financial Statements and Supplementary Data.”
(8) Pro forma general and administrative expenses do not include additional expenses we would have incurred as a result of being a public company for the entire period presented. In addition, non-recurring general and administrative expenses associated with non-cash compensation expense and IPO bonus amounts were excluded from the pro forma general and administrative expenses.

Productive Wells

As of December 31, 2014, we owned an interest in 669 gross (365 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, 2014 relating to our leasehold acreage:

	Developed acreage(1)		Undeveloped acreage(2)		Total acreage	
	Gross	Net	Gross	Net	Gross	Net
Midland Basin	23,280	12,824	39,168	34,190	62,448	47,014

(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.

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, 2014, 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.

	2015		2016		2017		2018		2019	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Midland Basin	5,906	5,393	9,775	8,447	4,585	3,927	42	37	—	—

Drilling Results

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.

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	RSP Permian, Inc. (1)		Predecessor (2)			
	For the Year Ended December 31,					
	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive(1)	2.0	1.7	—	—	1.0	0.4
Dry	—	—	—	—	—	—
Total Exploratory	2.0	1.7	—	—	1.0	0.4
Development Wells:						
Productive(1)	147.0	84.1	102.0	52.9	108.0	68.8
Dry	—	—	—	—	—	—
Total Development	147.0	84.1	102.0	52.9	108.0	68.8
Total Wells:						
Productive(1)	149.0	85.8	102.0	52.9	109.0	69.2
Dry	—	—	—	—	—	—
Total	149.0	85.8	102.0	52.9	109.0	69.2

(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) 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.

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.

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PART II

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." Initial trading of our common stock commenced on January 17, 2014. Accordingly, no market for our common stock existed prior to that date. The table below sets forth, for the periods indicated, the high and low sales prices per share of our common stock since January 17, 2014.

	2014			
	First Quarter (1)	Second Quarter	Third Quarter	Fourth Quarter
Low	$19.50	$25.73	$23.77	$19.36
High	$30.34	$33.67	$32.94	$30.06

(1) For the period from January 17, 2014 through March 31, 2014.

On March 10, 2015, the Company's common stock was held by twenty-four 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.

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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 Permian, Inc."

The selected historical consolidated financial data of our predecessor as of and for the years ended on December 31, 2013, 2012 and 2011 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), and the selected financial data of the Company as of December 31, 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.(1)				RSP Permian, Inc. Pro Forma	
	Year Ended December 31,				Year Ended December 31,	
	2014	2013	2012	2011	2014	2013
					(Unaudited)	
	(In thousands, except per share data)					
Statement of Operations Data:						
Revenues:						
Oil sales	$253,371	$110,345	$91,441	$56,772	$ 257,830	$ 177,415
Natural gas sales	10,572	5,383	4,284	7,217	10,762	7,647
NGL sales(2)	17,982	7,314	8,702	—	18,317	11,644
Total revenues	$281,925	$123,042	$104,427	$63,989	$ 286,909	$ 196,706
Operating expenses:						
Lease operating expenses	$34,704	$14,113	$12,693	$5,521	$ 35,398	$ 22,667
Production and ad valorem taxes	19,758	8,326	7,575	4,192	20,009	13,236
Depreciation, depletion and amortization	87,844	47,158	48,803	16,612	91,477	80,487
Exploration	3,854	551	161	191	3,854	551
Asset retirement obligation accretion	142	121	115	46	151	199
Impairments	4,344	—	—	2,241	4,344	—
General and administrative expenses	38,357	3,852	2,859	3,509	17,619	3,716
Total operating expenses	189,003	74,121	72,206	32,312	172,852	120,856
(Gain) loss on sale of assets	13	(22,700)	(6,734)	(105,333)	13	—
Operating income	$92,909	$71,621	$38,955	$137,010	$ 114,044	$ 75,850
Other income (expense):						
Other income (expenses), net	$(44)	$1,202	$884	$163	$ (44)	$ 1,202
Gain (loss) on derivative instruments	81,470	(2,607)	(796)	(1,979)	81,470	(2,607)
Interest expense	(14,031)	(5,216)	(3,474)	(3,472)	(14,031)	(10,890)
Total other income (expense)	$67,395	$(6,621)	$(3,386)	$(5,288)	$ 67,395	$ (12,295)
Income before taxes	160,304	65,000	35,569	131,722	181,439	63,555
Income tax (expense) benefit	(157,806)	(2,262)	339	(550)	(65,318)	(22,717)
Net Income	$2,498	$62,738	$35,908	$131,172	$ 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 for income taxes	(57,709)	(22,586)				
Pro forma net income	$102,595	$40,152				
Cash Flow Data:						

Net cash provided by operating activities	$223,157	$73,345	$72,803	$26,243
Net cash provided by (used in) investing activities	(816,925)	(119,591)	(113,220)	83,846
Net cash provided by (used in) financing activities	636,826	8,248	81,583	(105,155)

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(1) Represents our predecessor’s historical financial data for the first 22 days of the quarter plus RSP Permian, Inc.'s historical financial data for the remainder of the quarter.
(2) In 2011, we did not track NGLs as a separate product category; instead, NGL production and sales were included in our natural gas production and sales.
(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 2012 and 2013 as if our predecessor was subject to income taxes as a C-Corp. since January 1, 2012. 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,			
	2014	2013	2012	2011
	(In thousands)			
Balance Sheet Data:				
Cash and cash equivalents	$56,292	$13,234	$51,232	$10,066
Other current assets	117,450	33,901	31,124	27,362
Total current assets	173,742	47,135	82,356	37,428
Property, plant and equipment, net	2,094,618	516,288	421,412	349,598
Other long-term assets	21,587	24,232	9,470	8,636
Total assets	$2,289,947	$587,655	$513,238	$395,662
Current liabilities	130,041	30,866	28,165	27,916
Long-term debt	500,000	128,155	111,586	46,586
NPI payable	—	36,931	16,583	—
Other long-term liabilities	334,135	4,822	3,061	3,225
Total stockholders'/members’ equity	1,325,771	386,881	353,843	317,935
Total liabilities and stockholders'/members’ equity	$2,289,947	$587,655	$513,238	$395,662

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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 Permian, Inc.

RSP Permian, Inc. was formed in September 2013 and, prior to the consummation of our IPO, did not have historical financial operating results. The historical results of RSP LLC and Rising Star, 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, which 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, became a wholly owned subsidiary of RSP Permian, Inc. See "-The IPO and Related Transactions-Corporate Reorganization" for more information. Also in connection with the IPO, Rising Star contributed to RSP Permian, 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 Permian, Inc.'s common stock and cash. See "-The IPO and Related Transactions-The Rising Star Acquisition" for more information.

Overview and Outlook

Our financial and operating performance and significant events in 2014 included the following highlights:

- Increased our average daily production rate 63% in 2014 as compared to 2013 on a pro forma basis.
- Increased proved reserves 97% to 106.4 MMBoe (39% proved developed) at year end 2014 as a result of our successful horizontal and vertical drilling program in multiple formations.
- Increased total horizontal and vertical inventory by 50% to 3,268 gross locations at year end 2014 as a result of acquisitions and increased downspacing.
- Maintained a strong year-end balance sheet with $556 million of liquidity.
- Acquired additional acreage in Martin, Glasscock and Dawson Counties.
- In Martin County, we acquired a 17.5% non-operated working interest in producing properties located between our operated leasehold positions, which properties include 6,451 gross (1,125 net) acres.
- In Glasscock County, we acquired a 100% operated working interest in 961 acres of undeveloped leasehold and 7,680 gross (6,652 net) surface acres, adding another primary operating area in the core of the Northern Midland Basin.
- In Dawson County, we acquired 3,766 gross (3,230 net) undeveloped acres.
- Completed our IPO in January, selling 23 million shares of our common stock, with approximately 9.2 million shares sold by RSP Permian, Inc., resulting in approximately $163 million of net proceeds.
- Completed a follow-on underwritten public offering of 11.5 million shares of our common stock, with approximately 4.8 million shares sold by RSP Permian, Inc., resulting in approximately $117.8 million of net proceeds.
- Issued $500 million of 6.625% of senior notes due 2022 in a private placement.
- Entered into amendments to our revolving credit facility that increased our borrowing base from $140 million at the beginning of the year to $500 million, increased the maximum commitment from $500 million to $1 billion and extended the maturity date from September 17, 2017 to August 29, 2019.

During 2014, our average daily production was 11,679 Boe/d, a 153% increase from our 2013 average daily production of 4,611 Boe/d. On a pro forma basis, our average daily production for 2014 was 11,868 Boe/d, a 63%

increase from our 2013 pro forma amount of 7,293 Boe/d. Oil production was 72% of total production on a volumetric basis and 90% of our total revenues in 2014.

During 2014, we drilled 77 horizontal wells (41 operated) and completed 66 horizontal wells (33 operated). In our vertical drilling program, we drilled 72 vertical wells (47 operated) and completed 62 vertical wells (40 operated). During 2014, we ramped up to four operated horizontal rigs from two operated horizontal rigs and four operated vertical rigs from one operated vertical rig before releasing two vertical rigs near the end of the year. We added a fifth horizontal rig in early 2015. We intend to reduce our operated horizontal rig count to three and have no vertical rigs by the end of 2015.

Beginning in the fourth quarter of 2014, crude oil prices declined significantly from highs in the first half of 2014. This decline in crude oil prices challenges oil and gas producers like ourselves due to a corresponding reduction in our revenue and

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cash flow. See “Part I, Item 1A. Risk Factors- Oil, NGL and natural gas prices are volatile and have recently declined significantly. If oil, NGL and natural gas prices do not improve or decline further, our business, financial condition, results of operations and ability to meet our capital expenditure obligations and financial commitments may be materially and adversely affected.” Management believes that we are well-positioned as a result of a strong balance sheet, capitalization and access to our revolving credit facility, and the flexibility to reduce capital expenditures if crude oil prices remain at lower levels. Further, we expect increases in production and reserves in 2015, which should benefit the Company as it operates in a lower crude oil price environment.

Our board of directors has approved a capital budget for drilling, completion, and infrastructure for 2015 of approximately $400 to $450 million. We have the capacity to fund our 2015 capital expenditures with expected cash generated by operations and borrowings under our revolving credit facility. Historically, the Company has used the debt and equity capital markets to sell securities to fund a portion of its operations. The Company continually reviews various capital markets transactions as a source of funding for its capital program. We intend to allocate our 2015 capital budget (which excludes acquisitions) approximately as follows:

- $380 to $420 million for drilling and completion activities, approximately 15% of which is non-operated drilling and completion activities; and
- $20 to $30 million for infrastructure and other.

How We Evaluate Our Operations

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

- production volumes;
- realized prices on the sale of oil, NGLs and natural gas, including the effect of our commodity derivative contracts on our production;
- revenues; and
- lease operating expenses.

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 anticipated 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.

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Our open positions as of December 31, 2014 were as follows:

Description & Production Period	Volume (Bbls)	Weighted Average Floor price ($/Bbl)(1)	Weighted Average Ceiling price ($/Bbl)(1)	Weighted Average Swap price ($/Bbl)(1)
Crude Oil Swaps:				
January 2015 — December 2015	120,000			$92.60
Crude Oil Collars:				
January 2015 — December 2015	300,000	$85.00	$95.00	
January 2015 — March 2015	195,000	$90.00	$94.89	
January 2015 — June 2015	240,000	$90.00	$96.00	
January 2015 — December 2015	1,332,000	$85.86	$94.64	
April 2015 — June 2015	90,000	$85.00	$93.67	
July 2015 — September 2015	90,000	$85.00	$92.60	
October 2015 — December 2015	90,000	$85.00	$92.33	

(1) The crude oil derivative contracts are settled based on the month’s average daily NYMEX price of West Texas Intermediate Light Sweet Crude.

Factors Affecting the Comparability of Our Financial Condition and Results of Operations

Our historical financial condition and results of operations for the periods presented may not be comparable, either from period to period or going forward, for the following reasons:

The IPO and Related Transactions

The historical results of operations from before our IPO are based on the financial statements of our predecessor, which reflects the combined results of RSP LLC and Rising Star. In January 2014, we successfully completed our IPO, and in connection with our IPO, we completed the transactions described below, which changed our structure and increased the scope of our operations.

Corporate Reorganization. Pursuant to the terms of a corporate reorganization, (i) the members of RSP LLC contributed all of their interests in RSP LLC to RSP Permian Holdco, L.L.C., a newly formed entity that is wholly owned by such members, and (ii) RSP Permian Holdco, L.L.C. contributed all of its interests in RSP LLC to RSP Permian, Inc. in exchange for approximately 28.5 million shares of common stock of RSP Permian, Inc., an assignment of RSP LLC’s pro rata share of an escrow related to a disposition by RSP LLC of working interests and the right to receive approximately $27.7 million in cash. As a result of the reorganization, RSP LLC became a wholly owned subsidiary of RSP Permian, Inc.

The Rising Star Acquisition. In connection with our IPO, we acquired from Rising Star working interests (the “Rising Star Assets”) in certain acreage and wells in the Permian Basin in which RSP LLC already had working interests (the “Rising Star Acquisition”). In exchange, Rising Star received approximately 1.8 million shares of RSP Permian, Inc.’s common stock and the right to receive approximately $1.7 million in cash. The Rising Star Acquisition increased our average working interest in approximately 3,250 gross acres and 36 gross producing wells in the Permian Basin. The Rising Star Assets represented substantially all of Rising Star’s production and revenues for the years ended December 31, 2013 and 2012.

The Collins and Wallace Contributions. Collins, Wallace LP and Collins & Wallace Holdings, LLC contributed to us certain working interests in certain of RSP LLC's existing properties in the Permian Basin. In exchange, (i) Collins received approximately 9.9 million shares of RSP Permian, Inc.'s common stock and the right to receive approximately $1.6 million in cash, (ii) Wallace LP received approximately 10.0 million shares of RSP Permian, Inc.'s common stock and the right to receive approximately $0.6 million in cash, and (iii) Collins & Wallace Holdings, LLC received approximately 2.2 million shares of RSP Permian, Inc.'s common stock.

The Pecos Contribution. Pecos, an entity owned by certain members of our management team, contributed to us certain working interests in certain acreage and wells in the Permian Basin in which RSP LLC already had working interests. In

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exchange, Pecos received approximately 0.1 million shares of RSP Permian, Inc.'s common stock. Pecos's contribution increased our working interests in approximately 650 gross acres and six producing wells.

The ACTOIL NPI Repurchase. In July 2011, RSP LLC sold to ACTOIL a 25% net profits interest ("NPI") in substantially all of our oil and natural gas properties taken as a whole. In addition, in connection with RSP LLC's acquisition of additional working interests in certain of its existing properties (the "Spanish Trail Assets") in September 2013 (the "Spanish Trail Acquisition"), RSP LLC sold to ACTOIL a 25% NPI in the Spanish Trail Assets. Subsequent to our sale to ACTOIL of the NPIs, the oil and natural gas properties that underpinned ACTOIL's NPIs remained owned and controlled by us. The NPIs entitled ACTOIL to 25% of the relevant properties' cumulative revenues in excess of their cumulative direct operating expenses and capital expenditures. In connection with the IPO, ACTOIL contributed both 25% NPIs to us (the "ACTOIL NPI Repurchase") in exchange for approximately 10.8 million shares of RSP Permian, Inc.'s common stock.

Public Company Expenses

We incur direct, incremental general and administrative expenses as a result of being a publicly traded company, including, but not limited to, increased scope of our operations as a result of recent activities and costs associated with hiring new personnel, implementation of compensation programs that are competitive with our public company peer group, annual and quarterly reports to stockholders, tax return preparation, independent auditor fees, investor relations activities, registrar and transfer agent fees, incremental director and officer liability insurance costs and independent director compensation. Some of these direct, incremental general and administrative expenses are not included in our historical results of operations prior to the IPO.

Income Taxes

Our predecessor was not subject to federal income taxes and the tax liability with respect to our taxable income was passed through to our predecessor's members. Accordingly, the financial data attributable to our predecessor contain no provision for federal income taxes. Our predecessor was subject to State of Texas franchise taxes at less than 1% of modified pre-tax earnings. We are taxed as a subchapter C corporation under the Internal Revenue Code of 1986, as amended, and subject to income taxes at a blended statutory rate of 36% of pre-tax earnings.

2015 Capital Budget

Our board of directors has approved a capital budget for drilling, completion, and infrastructure for 2015 of approximately $400 to $450 million. The ultimate amount of capital that we spend may fluctuate materially based on market conditions and our drilling results.

Results of Operations

Year Ended December 31, 2014 Compared to Year Ended December 31, 2013

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,				
	2014	2013	Change	% Change	
Revenues (in thousands, except percentages):					
Oil sales	$253,371	$110,345	$143,026	130	%

Natural gas sales	10,572	5,383	5,189	96 %
NGL sales	17,982	7,314	10,668	146 %
Total revenues	$281,925	$123,042	$158,883	129 %
Average sales prices:				
Oil (per Bbl) (excluding impact of cash settled derivatives)	$83.10	$94.55	$(11.45)	(12)%
Oil (per Bbl) (after impact of cash settled derivatives)	85.01	94.17	(9.16)	(10)%
Natural gas (per Mcf)	3.55	3.37	0.18	5 %
Natural gas (per Mcf) (after impact of cash settled derivatives)	3.59	3.37	0.22	7 %
NGLs (per Bbl)	25.04	29.26	(4.22)	(14)%
Total (per Boe) (excluding impact of cash settled derivatives)	$66.13	$73.11	$(6.98)	(10)%
Total (per Boe) (after impact of cash settled derivatives)	$67.53	$72.84	$(5.31)	(7)%
Production:				
Oil (MBbls)	3,049	1,167	1,882	161 %
Natural gas (MMcf)	2,974	1,597	1,377	86 %
NGLs (MBbls)	718	250	468	187 %
Total (MBoe)	4,263	1,683	2,580	153 %
Average daily production volume:				
Total (Boe/d)	11,679	4,611	7,068	153 %

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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, liquids rich natural gas with a high Btu content sells 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,			
	2014		2013	
Average realized oil price ($/Bbl)	$83.10		$94.55	
Average NYMEX ($/Bbl)	93.00		98.02	
Differential to NYMEX	(9.90	)	(3.47	)
Average realized oil price to NYMEX percentage	89	%	96	%
Average realized natural gas price ($/Mcf)	$3.55		$3.37	
Average NYMEX ($/Mcf)	4.26		3.73	
Differential to NYMEX	(0.71	)	(0.36	)
Average realized natural gas price to NYMEX percentage	83	%	90	%
Average realized NGL price ($/Bbl)	$25.04		$29.26	
Average NYMEX oil price ($/Bbl)	93.00		98.02	
Average realized NGL price to NYMEX oil price percentage	27	%	30	%

Our average realized oil price as a percentage of the average NYMEX price decreased to 89% for the year ended December 31, 2014 as compared to 96% 2013. All of our oil contracts are impacted by the Midland-Cushing differential, which was negative $6.90 per Bbl in 2014 as compared to negative $2.64 per Bbl in 2013. As the differential increased, our realized price per barrel of oil decreased. Transportation pipelines in the Midland to Cushing corridor became oversupplied and caused the differential to increase relative to historical norms. This differential has begun to narrow in recent months as new pipeline infrastructure has been put into service, alleviating pipeline capacity constraints.

Oil revenues increased 130% to $253.4 million for the year ended December 31, 2014 from $110.3 million for 2013 as a result of an increase in oil production volumes of 1,882 MBbls partially offset by an $11.45 per Bbl decrease in our average realized price for oil.

Natural gas revenues increased 96% to $10.6 million for the year ended December 31, 2014 from $5.4 million for 2013 as a result of an increase in natural gas production volumes of 1,377 MMcf and a $0.18 per Mcf increase in our average realized natural gas price.

NGL revenues increased 146% to $18.0 million for the year ended December 31, 2014 to $7.3 million for 2013 as a result of an increase in NGL production volumes of 468 MBbls partially offset by a $4.22 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, the Spanish Trail Acquisition in September 2013, the Collins and Wallace Contributions in January 2014, the acquisition of producing properties in Martin County in February 2014, and the acquisition of producing properties in Glasscock County in August 2014.

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

	Year Ended December 31, 2014	2013	$ Change	% Change
Operating expenses (in thousands, except percentages):				
Lease operating expenses	$34,704	$14,113	$20,591	146 %
Production and ad valorem taxes	19,758	8,326	11,432	137 %
Depreciation, depletion and amortization	87,844	47,158	40,686	86 %
Asset retirement obligation accretion	142	121	21	17 %
Impairment	4,344	—	4,344	NM
Exploration expense	3,854	551	3,303	599 %
General and administrative expenses	38,357	3,852	34,505	896 %
Total operating expenses before loss (gain) on sale of assets	$189,003	$74,121	$114,882	155 %
Loss (gain) on sale of assets	13	(22,700)	22,713	NM
Total operating expenses after gain on sale of assets	$188,990	$96,821	$92,169	95 %
Expenses per Boe:				
Lease operating expenses (excluding gathering and transportation)	$7.49	$7.79	(0.30)	(4)%
Gathering and transportation	0.65	0.60	0.05	8 %
Production and ad valorem taxes	4.63	4.95	(0.32)	(6)%
Depreciation, depletion and amortization	20.61	28.02	(7.41)	(26)%
Asset retirement obligation accretion	0.03	0.07	(0.04)	(57)%
Impairment	1.02	—	1.02	NM
Exploration expense	0.90	0.33	0.57	173 %
General and administrative - cash component	4.25	2.29	1.96	86 %
General and administrative - (non IPO stock comp)(1)	0.64	—	0.64	NM
General and administrative - (IPO stock comp)(2)	4.11	—	4.11	NM
Total operating expenses per Boe	$44.33	$44.05	$0.28	1 %

(1) Represents 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 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 146% to $34.7 million for the year ended December 31, 2014 from $14.1 million for 2013. The increase in our lease operating expense was attributable to the increase in production in 2014 along with higher workover costs, as we performed more workovers in 2014 primarily related to wells affected by severe winter weather in early 2014. On a per Boe basis, lease operating expense decreased from $7.79 per Boe in 2013 to $7.49 per Boe in 2014. Gathering and transportation costs, which are included in lease operating expenses, were $2.8 million and $1.0 million for the years ended December 31, 2014 and 2013, respectively. On a per Boe basis, our gathering and transportation costs were $0.65 and $0.60 for the years ended December 31, 2014 and 2013, respectively.

Production and Ad Valorem Taxes. Production and ad valorem taxes increased 137% to $19.8 million for the year ended December 31, 2014 from $8.3 million for 2013 primarily as a result of higher wellhead revenues but decreased 6% on a per Boe basis to $4.63 per Boe in 2014.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (“DD&A”) expense increased 86% to $87.8 million for the year ended December 31, 2014 from $47.2 million for 2013 mainly due to increased production and costs related to property acquisitions. The DD&A rate decreased 26% to $20.61 per Boe for the year ended December 31, 2014 from

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$28.02 per Boe for 2013. The decrease in depletion per Boe in 2014 was due to our reserves volumes in 2014, both from our successful drilling program and through acquisitions, more than offsetting additional capitalized costs in proved property incurred from these activities, which further reduced our DD&A rate in 2014 when compared to 2013.

Impairment. We incurred $4.3 million of impairment expense on unproved property in 2014. The impairment related to acreage pending lease expirations that the Company does not intend to renew.

Exploration Expense. Exploration expense increased to $3.9 million for the year ended December 31, 2014 from $0.6 million for 2013 due to additional geological and geophysical activity in 2014.

General and Administrative Expenses. General and administrative expenses increased to $38.4 million for the year ended December 31, 2014, from $3.9 million for 2013 primarily due to increases in non-cash incentive unit compensation and equity-based compensation and increases in compensation expense associated with additions to personnel. Share-based compensation expense, which was recorded in General and administrative expenses, was $20.2 million for the year ended December 31, 2014. Included in share-based compensation was compensation expense related to normal recurring equity-based payment programs for employees ($2.7 million), the one-time issuance of restricted stock awards as a result of our successful IPO ($2.8 million), and amounts related to incentive units ($14.7 million) that were owned by certain members of management. These incentive units provided a mechanism for the allocation of stock between members of management and the Company's private equity sponsor based upon return thresholds achieved. The stock issued to certain members of management and the expense recognized in the consolidated statement of operations as a result of these incentive units had no dilution effect to public shareholders, and was a non-cash expense. The increase in general and administrative expenses related to additions in personnel was approximately $12.7 million for the 2014 period.

Gain on Sale of Assets. Gain on sale of assets was $22.7 million for the year ended December 31, 2013, as a result of the property sale to Resolute in 2013. There were no material asset sales in 2014.

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

	Year Ended December 31, 2014	2013	$ Change	% Change
Other income (expense) (in thousands, except percentages):				
Other income (expense), net	$(44)	$1,202	$(1,246)	NM
Gain (loss) on derivative instruments	81,470	(2,607)	84,077	NM
Interest expense	(14,031)	(5,216)	(8,815)	(169)%
Total other income (expense)	$67,395	$(6,621)	$74,016	NM

Other Income. Other income was $1.2 million for the year ended December 31, 2013, primarily due to water we sourced and sold to other working interest partners for use in completion activities in 2013.

Gain (Loss) on Derivative Instruments. During the year ended December 31, 2014, we recorded an $81.5 million gain as compared to a $2.6 million loss in 2013. The change was a result of the future commodity price outlook as of December 31, 2014 as compared to December 31, 2013, along with additional hedges entered into during 2014.

Interest Expense. During the year ended December 31, 2014, we recorded $14.0 million of interest expense as compared to $5.2 million in 2013. The change was primarily the result of additional borrowings under our revolving credit facility in 2014 and the expense incurred on our notes issued in September 2014.

Income Tax Expense. During the year ended December 31, 2014, we recorded $157.8 million of income tax expense compared to $2.3 million in 2013. The increase is as a result of our being taxed as a subchapter C corporation under the Internal Revenue Code of 1986, as amended, and subject to income taxes at a blended statutory rate of 36% of pre-tax earnings, exclusive of permanent differences. 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 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.

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Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

Oil, NGL 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, 2013	2012	$ Change		% Change	
Revenues (in thousands, except percentages):						
Oil sales	$110,345	$91,441	$18,904		21	%
Natural gas sales	5,383	4,284	1,099		26	%
NGL sales	7,314	8,702	(1,388	)	(16	)%
Total revenues	$123,042	$104,427	$18,615		18	%
Average sales prices:						
Oil (per Bbl) (excluding impact of cash settled derivatives)	$94.55	$87.92	$6.63		8	%
Oil (per Bbl) (after impact of cash settled derivatives)	94.17	88.25	5.92		7	%
Natural gas (per Mcf)	3.37	2.72	0.65		24	%
NGLs (per Bbl)	29.26	32.94	(3.68	)	(11	)%
Total (per Boe) (excluding impact of cash settled derivatives)	$73.11	$66.65	$6.46		10	%
Total (per Boe) (after impact of cash settled derivatives)	$72.84	$66.86	$5.98		9	%
Production:						
Oil (MBbls)	1,167	1,040	127		12	%
Natural gas (MMcf)	1,597	1,576	21		1	%
NGLs (MBbls)	250	264	(14	)	(5	)%
Total (MBoe)	1,683	1,567	116		7	%
Average daily production volume:						
Total (Boe/d)	4,611	4,293	318		7	%

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 years indicated. Management uses the realized price to NYMEX margin analysis to analyze trends in our oil and natural gas revenues.

	Year Ended December 31, 2013		2012	
Average realized oil price ($/Bbl)	$94.55		$87.92	
Average NYMEX ($/Bbl)	98.02		94.15	
Differential to NYMEX	(3.47	)	(6.23	)
Average realized oil price to NYMEX percentage	96	%	93	%
Average realized natural gas price ($/Mcf)	$3.37		$2.72	
Average NYMEX ($/Mcf)	3.73		2.83	
Differential to NYMEX	(0.36	)	(0.11	)
Average realized natural gas price to NYMEX percentage	90	%	96	%

Average realized NGL price ($/Bbl)	$29.26	$32.94
Average NYMEX oil price ($/Bbl)	98.02	94.15
Average realized NGL price to NYMEX oil price percentage	30 %	35 %

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Our average realized oil price as a percentage of the average NYMEX price increased to 96% for the year of 2013 as compared to 93% for 2012. All of our oil contracts are impacted by the NYMEX differential, which was negative $3.47 per Bbl in 2013 as compared to negative $6.23 per Bbl in 2012. Our average realized natural gas price as a percentage of the average NYMEX price was 90% for 2013 and 96% for 2012.

Oil revenues increased 21% from $91.4 million for the year ended December 31, 2012 to $110.3 million for 2013 as a result of a $6.63 per Bbl increase in our average realized price for oil, compounded by an increase in oil production volumes of 127 MBbls. Our higher oil production was a result of increased production from our horizontal drilling program and the Spanish Trail Acquisition in September 2013. This increase was partially offset by the partial sale of 80 producing wells to Resolute in March 2013, which accounted for 38% of total production for the year ended December 31, 2012 compared to 7% of total production for the year ended December 31, 2013.

Natural gas revenues increased 26% from $4.3 million for the year ended December 31, 2012 to $5.4 million for 2013 as a result of an increase in natural gas production volumes of 21 MMcf and a $0.65 per Mcf increase in our average realized natural gas price. Our increase in natural gas production was a result of increased production from our horizontal drilling program along with our Spanish Trail acquisition in September 2013 offset by the partial sale of producing wells to Resolute in March 2013.

NGL revenues decreased 16% from $8.7 million for twelve months ended December 31, 2012 to $7.3 million for the 2013 period as a result of a $3.68 per Bbl decrease in our average realized NGL price and a 5% decrease in production. Our lower average realized NGL price was primarily due to increased supplies of NGLs produced from NGL-rich shales in the Permian Basin and other basins, which has resulted in a decrease in prices received for NGLs.

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

	Year Ended December 31,			
	2013	2012	$ Change	% Change
Operating expenses (in thousands, except percentages):				
Lease operating expenses	$14,113	$12,693	$1,420	11%
Production and ad valorem taxes	8,326	7,575	751	10%
Depreciation, depletion and amortization	47,158	48,803	(1,645)	(3)%
Exploration expense	551	161	390	NM
Asset retirement obligation accretion	121	115	6	5%
General and administrative expenses	3,852	2,859	993	35%
Total operating expenses before gain on sale of assets	$74,121	$72,206	$1,915	3%
(Gain) on sale of assets	(22,700)	(6,734)	(15,966)	NM
Total operating expenses after gain on sale of assets	51,421	65,472	(14,051)	(21)%
Expenses per Boe:				
Lease operating expenses (excluding gathering and transportation)	$7.79	$7.64	$0.15	2%
Gathering and transportation	0.60	0.46	0.14	30%
Production and ad valorem taxes	4.95	4.83	0.12	2%
Depreciation, depletion and amortization	28.02	31.15	(3.13)	(10)%
Asset retirement obligation accretion	0.07	0.07	—	—%
Exploration Expense	0.33	0.10	0.23	NM
General and administrative	2.29	1.82	0.47	26%

Total operating expenses per Boe	$44.05	46.07	(2.02)	(4)%

Lease Operating Expenses. Lease operating expenses increased 11% to $14.1 million for the year ended December 31, 2013 from $12.7 million for 2012. The increase in our average lease operating expenses was attributable to increased drilling activity, which resulted in additional producing wells in 2013 as compared to 2012. Our lease operating expense was impacted by costs of gathering and transportation and increases in third party operated lease operating expense, offset by savings achieved through 2013 infrastructure projects that have resulted in efficiencies in our field operations and, in particular, putting additional oil volumes on pipeline compared to trucking.

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Production and Ad Valorem Taxes. Production and ad valorem taxes increased 10% to $8.3 million for the year ended December 31, 2013 from $7.6 million for 2012 primarily as a result of higher wellhead revenues.

Depreciation, Depletion and Amortization. DD&A expense decreased 3% to $47.2 million for the year ended December 31, 2013 from $48.8 million for 2012 due to a decrease in our per Boe DD&A rate. The DD&A rate decreased 10% to $28.02 per Boe for the year ended December 31, 2013 from $31.15 per Boe for 2012, as a result of additional drilling activity due to an addition of 115 wells during 2013 and the related increase in our reserve estimates used in computing depreciation.

Exploration Expense. Exploration expense increased to $0.6 million for the year ended December 31, 2013 from $0.2 million for 2012 due to additional geological and geophysical activity in the 2013 period.

General and Administrative Expenses. General and administrative expenses increased 35% to $3.9 million for the year ended December 31, 2013 from $2.9 million for 2012 primarily due to increases in advisory fees associated with our property sale to Resolute in March 2013 and asset purchase of Spanish Trail Assets in September 2013 and increases in compensation expense associated with additions to personnel.

Gain on Sale of Assets. Gain on sale of assets increased to a $22.7 million gain for the year ended December 31, 2013 from a $6.7 million gain for 2012 as a result of the property sale to Resolute in March 2013.

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

	Year Ended December 31,			
	2013	2012	$ Change	% Change
Other income (expense) (in thousands, except percentages):				
Other income	$1,202	$884	$318	36%
Loss on derivative instruments	(2,607)	(796)	(1,811)	228%
Interest expense	(5,216)	(3,474)	(1,742)	50%
Total other income (expense)	$(6,621)	$(3,386)	$(3,235)	96%

Other Income. Other income increased 36% to $1.2 million for the year ended December 31, 2013 from $0.9 million for 2012 primarily due to an increase in income related to water we sourced and sold to other working interest partners for use in completion activities.

Loss on Derivative Instruments. During the year ended December 31, 2013 we recorded a $2.6 million loss as compared to a $0.8 million loss in 2012. The change was a result of the future commodity price outlook during 2013 as compared to 2012.

Interest Expense. During the year ended December 31, 2013, we recorded $5.2 million of interest expense as compared to $3.5 million in 2012. The change was primarily the result of the accelerated amortization of deferred financing costs associated with our previous credit facility of $1.2 million into interest expense in 2013.

Capital Requirements and Sources of Liquidity

The Company’s primary sources of liquidity have been capital contributions from its equity sponsor (prior to the IPO), proceeds from the IPO and secondary stock offering, borrowings under the revolving credit facility, term loan borrowings, proceeds from the issuance of the notes, proceeds from asset dispositions, proceeds from the issuance of net profits interests 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.

In 2014, we used a portion of the net proceeds from the IPO to fully repay our term loan and outstanding borrowings under our revolving credit facility. Later in August and September 2014, we used the proceeds from our stock offering and notes offering to repay all borrowings under our revolving credit facility. At December 31, 2014, we had no borrowings outstanding under our revolving credit facility and our borrowing base was $500 million.

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During 2014, we spent approximately $442 million on drilling and completion activities, $42 million of infrastructure and other, and approximately $362 million of acquisitions and additions to leasehold. Of the total capital spent, approximately $55 million was on non-operated properties and approximately $62 million was on wells the Company drilled but expects to complete in 2015.

Our 2015 capital budget for drilling, completion, recompletion and infrastructure is approximately $400 to $450 million. We intend to allocate our 2015 capital budget approximately as follows:

- $380 to $420 million, for the drilling and completion activities; and
- $20 to $30 million, for infrastructure and other.

Because we operate a high percentage of our acreage, the amount and timing of these capital expenditures are largely discretionary. We could choose to defer a portion of these planned 2015 capital expenditures depending on a variety of factors, including: 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 upon current expectations, we believe we have sufficient liquidity through our cash flow from operations and additional borrowings under our revolving credit facility to execute our current capital program excluding any acquisitions we may enter into. However, future cash flows are subject to a number of variables, including the level of oil and natural gas production and prices, and significant additional capital expenditures will be required to more fully develop our properties. 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 assure you 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.

Working Capital

Our working capital, which we define as current assets minus current liabilities, totaled $43.7 million and $16.3 million at December 31, 2014 and 2013, respectively. Our collection of receivables has historically been timely, and losses associated with uncollectible receivables have historically not been significant. Our cash balances totaled $56.3 million and $13.2 million at December 31, 2014 and 2013, 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 enter into. 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, 2014 is provided in the following table (in thousands).

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	Payments Due by Period For the Year Ended December 31,						
	2015	2016	2017	2018	2019	Thereafter	Total
	(In thousands)						
Revolving credit facility (1)	$—	$—	$—	$—	$—	$—	$—
6.625% Senior Notes (2)	—	—	—	—	—	500,000	500,000
Interest cost (3)	33,125	33,125	33,125	33,125	33,125	91,094	256,719
Drilling rig commitments (4)	34,296	19,440	1,645	—	—	—	55,381
Office and equipment leases	1,114	1,078	890	778	503	—	4,363
Asset retirement obligations (5)	—	—	—	—	—	4,873	4,873
Total	$68,535	$53,643	$35,660	$33,903	$33,628	$595,967	$821,336

(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.
(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.

Cash Flows

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

	Year Ended December 31,		
	2014	2013	2012
	(In thousands)		
Net cash provided by operating activities	$223,157	$73,345	$72,803
Net cash used in investing activities	(816,925)	(119,591)	(113,220)
Net cash provided by financing activities	636,826	8,248	81,583

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

Net cash provided by operating activities was approximately $223.2 million, $73.3 million, and $72.8 million for the year ended December 31, 2014, 2013, and 2012, respectively. Revenues and related cash flows from operations increased in 2014 as compared to 2013 due to increased production from our horizontal drilling program, the Spanish Trail Acquisition in September 2013, the Collins and Wallace Contributions in January 2014 and the acquisition of producing properties in Martin County in February 2014. Revenues increased in 2013 over 2012; however, the increase was offset by changes in other assets and liabilities and net cash provided by operating activities was flat year over year.

Net cash used in investing activities was approximately $816.9 million, $119.6 million, and $113.2 million for the year ended December 31, 2014, 2013, and 2012, respectively. The increase in the amount of cash used in investing activities in the 2014 period compared to the 2013 period was due to capital expenditures for drilling and completing wells along with additional acquisition activity in the 2014 period. Capital expenditures during 2013 were offset by proceeds received from the sale of properties to Resolute. The 2013 period includes the purchase of Spanish Trail assets offset by the sale of properties to Resolute and net cash used in investing activities was flat from period to period.

Net cash provided by financing activities was approximately $636.8 million, $8.2 million, and $81.6 million for the year ended December 31, 2014, 2013, and 2012, respectively. For the 2014 period, the increased cash provided by financing activities was primarily the result of capital contributions received in connection with the IPO, the secondary stock offering, along with the issuance of $500.0 million of senior notes in 2014. The 2013 period includes debt repayments of $85.0 million,

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while the 2012 period includes $90.0 million of borrowings, thus decreasing net cash provided by financing activities in the 2013 period compared to the 2012 period.

Our Revolving Credit Facility

In September 2013, in conjunction with the Spanish Trail Acquisition, we amended and restated our credit agreement, dated December 15, 2010, with Comerica Bank, as administrative agent, and expanded our syndicated bank group to 11 lenders and entered into a new term loan in the amount of $70 million, which was fully repaid in January 2014 with proceeds from our IPO. On June 9, 2014, we amended our credit agreement to reflect an increase in the borrowing base under our revolving credit facility from $300 million to $375 million in connection with our semiannual borrowing base redetermination. On August 29, 2014, in conjunction with the closing of our acquisitions in Glasscock County, we amended our credit agreement to increase the borrowing base to $500 million, increase the lenders' maximum facility commitments from $500 million to $1.0 billion, extend the maturity date from September 17, 2017 to August 29, 2019. On September 24, 2014, in connection with our issuance of the notes, we amended the credit agreement to permit RSP LLC to make payment to the Company to enable it to pay principal, premium (if any) and interest on the notes, provided no default has occurred, and to allow RSP LLC to guarantee the 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. Our next borrowing base redetermination is scheduled for May 2015. As of December 31, 2014, we had no borrowings and $0.4 million of letters of credit outstanding under our revolving credit facility and $499.6 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.

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

- a working capital ratio, which is the ratio of our consolidated current assets (includes unused commitments under our revolving credit facility and excludes restricted cash and derivative assets) to our 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 at the end of each fiscal quarter thereafter;
-

a senior secured leverage ratio, which is the ratio of the sum of all of our secured debt to our consolidated EBITDAX (as defined in our revolving credit facility) for the four fiscal quarters then ended, of not less than 3.5 to 1.0 commencing at the issuance of any Permitted Unsecured Notes (as defined in our revolving credit facility, but in any event including the notes offered hereby) and as of the last day of each fiscal quarter thereafter; and

- a leverage ratio, which is the ratio of the sum of all our debt to our consolidated EBITDAX (as defined in our revolving credit facility) for the four fiscal quarters then ended, of not greater than 4.5 to 1.0.

We were in compliance with such covenants and ratios as of December 31, 2014.

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. We have a choice of borrowing in Eurodollars 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 125 to 200 basis points, depending on the percentage of our borrowing base utilized. Adjusted base rate loans bear interest at a rate per annum equal to the greatest of: (i) the agent bank's reference rate; (ii) the federal funds effective rate plus 100 basis points; and (iii) the adjusted LIBOR rate plus 100 basis points, plus an applicable margin ranging from 25 to 100 basis points, depending on the percentage of our borrowing base utilized, plus a facility fee of 0.50% charged on the borrowing base amount. We may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs. As of December 31, 2014, our revolving credit facility has a margin of 1.00% to 2.00% plus LIBOR, plus a facility fee of 0.50% charged on the borrowing base amount.

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 exploratory wells, development wells, development-type stratigraphic test wells and service wells, including unsuccessful development wells, are capitalized.

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. The factors used to determine fair value are subject to our judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures and various discount rates commensurate with the risk associated with realizing the expected cash flows projected. We estimate fair value by discounting the projected future cash flows at an appropriate risk-adjusted discount rate.

Unproved leasehold costs are assessed at least annually to determine whether they have been impaired. Individually significant properties are assessed for impairment on a property-by-property basis, while individually insignificant unproved

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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.

Equity-Based Compensation

In connection with the IPO, the Company adopted the RSP Permian, Inc. 2014 Long Term Incentive Plan for the employees, consultants and directors of the Company and its affiliates who perform services for the Company. The valuation and expense recognition of equity-based compensation requires the use of estimates.

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."

Off-Balance Sheet Arrangements

As of December 31, 2014, we did not have any off-balance sheet arrangements.

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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 that 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.

Our open positions as of December 31, 2014 were as follows:

Description & Production Period	Volume (Bbls)	Weighted Average Floor price ($/Bbl)(1)	Weighted Average Ceiling price ($/Bbl)(1)	Weighted Average Swap price ($/Bbl)(1)
Crude Oil Swaps:				
January 2015 — December 2015	120,000			$92.60
Crude Oil Collars:				
January 2015 — December 2015	300,000	$85.00	$95.00	
January 2015 — March 2015	195,000	$90.00	$94.89	
January 2015 — June 2015	240,000	$90.00	$96.00	
January 2015 — December 2015	1,332,000	$85.86	$94.64	
April 2015 — June 2015	90,000	$85.00	$93.67	
July 2015 — September 2015	90,000	$85.00	$92.60	
October 2015 — December 2015	90,000	$85.00	$92.33	

(1) The crude oil derivative contracts are settled based on the month’s average daily NYMEX price of West Texas Intermediate Light Sweet Crude.

The fair value of our derivative contracts as of December 31, 2014 was a net asset of $75.7 million. For information regarding the terms of these hedges, see Note 4 of Notes to Consolidated Financial Statements included in "Part II, Item 8. Financial Statements and Supplementary Data."

Counterparty and Customer Credit Risk

Our commodity derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While we do not require counterparties to our 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.

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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, 2014, we had no borrowings outstanding that are subject to interest rate risk. 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 F-1 of this Report and is incorporated herein by reference.

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

None.

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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, 2014. 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, 2014 at the reasonable assurance level.

Attestation Report of the Registered Public Accounting Firm

Our independent registered public accounting firm will not be required to formally attest to the effectiveness of our internal controls over financial reporting for as long as we are an “emerging growth company” pursuant to the provisions of the Jumpstart Our Business Startups Act.

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, 2014 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

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, 2014, 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, 2014, 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 2015 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 2015 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 2015 and is incorporated herein by reference.

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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 2015 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 2015 and is incorporated herein by reference.

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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:

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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 3.2 of the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the Commission on January 29, 2014).
4.1	Specimen Common Stock Certificate (incorporated by reference to Exhibit 4.1 of the Company's Registration Statement on Form S-1 (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 September 26, 2014, by and among the Company, RSP Permian, L.L.C. and Barclays Capital Inc. and RBC Capital Markets, LLC, as representatives of the initial purchasers named in therein (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 October 2, 2014).
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(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).
10.6(c)	

	Form of Restricted Stock Grant and Award Agreement (Performance Vesting) (incorporated by reference to the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on April 16, 2014).
10.7(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).
10.8(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).
10.90	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 buyer (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).
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, 2014.
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.

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(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.

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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:	March 17, 2015

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)	March 17, 2015
/s/ Scott McNeill Scott McNeill	Chief Financial Officer and Director (Principal Financial Officer)	March 17, 2015
/s/ Barry S. Turcotte Barry S. Turcotte	Chief Accounting Officer (Principal Accounting Officer)	March 17, 2015
/s/ David Albin David Albin	Director	March 17, 2015
/s/ Joseph B. Armes Joseph B. Armes	Director	March 17, 2015
/s/ Ted Collins, Jr. Ted Collins, Jr.	Director	March 17, 2015
/s/ Mathew S. Ramsey Mathew S. Ramsey	Director	March 17, 2015
/s/ Michael W. Wallace Michael W. Wallace	Director	March 17, 2015

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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) and subsidiary (the "Company") as of December 31, 2014 and 2013, 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, 2014. 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. We were not engaged to perform an audit of the Company's internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, 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. and subsidiary as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Dallas, Texas
March 17, 2015

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RSP PERMIAN, INC.
CONSOLIDATED BALANCE SHEETS

	December 31, 2014	December 31, 2013
	(In thousands)	
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$56,292	$13,234
Accounts receivable	40,436	26,346
Accounts receivable, related party	—	3,672
Other assets	24	3,212
Derivative instruments	76,990	671
Total current assets	173,742	47,135
PROPERTY, PLANT AND EQUIPMENT		
Oil and natural gas properties, successful efforts method	2,240,803	595,486
Accumulated depletion and impairment	(171,046)	(88,514)
Total oil and natural gas properties, net	2,069,757	506,972
Other property and equipment, net	24,861	9,316
Total property, plant and equipment	2,094,618	516,288
OTHER LONG-TERM ASSETS		
Derivative instruments	—	1,078
Restricted cash	152	150
Other long-term assets	21,435	23,004
Total long-term assets	21,587	24,232
TOTAL ASSETS	$2,289,947	$587,655
LIABILITIES AND STOCKHOLDERS'/MEMBERS' EQUITY		
CURRENT LIABILITIES		
Accounts payable	$35,728	$18,548
Accrued expenses	57,977	10,460
Interest payable	9,227	296
Deferred taxes	25,789	—
Derivative instruments	1,320	1,562
Total current liabilities	130,041	30,866
LONG-TERM LIABILITIES		
Asset retirement obligations	4,873	2,584
Derivative instruments	—	43
Long-term debt	500,000	128,155
NPI payable	—	36,931
Deferred taxes	329,262	2,195
Total long-term liabilities	834,135	169,908
Total liabilities	964,176	200,774
STOCKHOLDERS'/MEMBERS' EQUITY		
Members' equity	—	386,881
Common stock, $.01 par value; 300,000,000 shares authorized, 77,903,834 shares issued and outstanding at December 31, 2014; no shares authorized, issued or outstanding at December 31, 2013	779	—
Additional paid-in capital	1,322,494	—

Retained earnings	2,498	—
Total stockholders'/members' equity	1,325,771	386,881
TOTAL LIABILITIES AND STOCKHOLDERS'/MEMBERS' EQUITY	$2,289,947	$587,655

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

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RSP PERMIAN, INC.
CONSOLIDATED STATEMENTS OF OPERATIONS

	For the year ended December 31,		
	2014	2013	2012
	(In thousands, except per share data)		
REVENUES			
Oil sales	$253,371	$110,345	$91,441
Natural gas sales	10,572	5,383	4,284
NGL sales	17,982	7,314	8,702
Total revenues	281,925	123,042	104,427
OPERATING EXPENSES			
Lease operating expenses	$34,704	$14,113	$12,693
Production and ad valorem taxes	19,758	8,326	7,575
Depreciation, depletion and amortization	87,844	47,158	48,803
Asset retirement obligation accretion	142	121	115
Impairments	4,344	—	—
Exploration	3,854	551	161
General and administrative expenses	38,357	3,852	2,859
Total operating expenses	189,003	74,121	72,206
Loss (gain) on sale of assets	13	(22,700)	(6,734)
OPERATING INCOME	$92,909	$71,621	$38,955
OTHER INCOME (EXPENSE)			
Other income (expenses), net	$(44)	$1,202	$884
Gain (loss) on derivative instruments	81,470	(2,607)	(796)
Interest expense	(14,031)	(5,216)	(3,474)
Total other income (expense)	67,395	(6,621)	(3,386)
INCOME BEFORE TAXES	160,304	65,000	35,569
INCOME TAX (EXPENSE) BENEFIT	(157,806)	(2,262)	339
NET INCOME	$2,498	$62,738	$35,908
Income per common share:			
Basic	$0.03		
Diluted	$0.03		
Weighted average shares outstanding:			
Basic	71,898		
Diluted	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	Total Stockholders' Equity/ Members' Equity
	(In thousands)					
BALANCE AT JANUARY 1, 2012	$317,935	—	$—	$—	$—	$317,935
Net Income	35,908	—	—	—	—	35,908
BALANCE AT DECEMBER 31, 2012	$353,843	—	$—	$—	$—	$353,843
Contributions	300	—	—	—	—	300
Distributions	(30,000)	—	—	—	—	(30,000)
Net Income	62,738	—	—	—	—	62,738
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

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

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RSP PERMIAN, INC.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	For the year ended December 31,		
	2014	2013	2012
	(In thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$2,498	$62,738	$35,908
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	87,844	47,158	48,347
Impairment	4,344	—	—
Abandoned equipment	—	2	135
Asset retirement obligation accretion	142	121	115
Equity-based compensation	20,232	—	—
Amortization of loan fees	1,202	1,746	456
Deferred income taxes	153,468	2,195	—
Equity in earnings of investment	98	(14)	(11)
Gain on certificate of deposit	—	—	(3)
Loss (gain) on sale of assets	13	(22,700)	(6,734)
(Gain) loss on derivative instruments	(81,470)	2,607	796
Net cash payments on settled derivatives	(102)	(886)	(474)
Changes in operating assets and liabilities:			
Accounts receivable and accounts receivable from related parties	(4,383)	(3,758)	(3,907)
Other assets	14,952	(17,739)	(2,148)
Interest payable	8,932	44	63
Accounts payable	17,180	(5,380)	(1,722)
Accrued expenses	(1,793)	7,211	1,982
Net cash provided by operating activities	$223,157	$73,345	$72,803
CASH FLOWS FROM INVESTING ACTIVITIES			
Proceeds from sale of assets	2	115,339	63,196
Acquisition of equity investment	(625)	—	(1,146)
Additions to other property and equipment	(5,475)	(3,265)	(1,287)
Additions to oil and natural gas properties	(810,827)	(231,665)	(173,983)
Net cash used in investing activities	$(816,925)	$(119,591)	$(113,220)
CASH FLOWS FROM FINANCING ACTIVITIES			
Contributions	—	300	—
Proceeds from issuance of common stock, net	280,703	—	—
Distributions	(1,663)	(30,000)	—
Payment of deferred loan costs	(14,059)	—	—
Borrowings under long-term debt	440,512	101,569	90,000
Restricted short-term investment	—	1,031	(25,000)
Payments on long-term debt	(568,667)	(85,000)	—
Issuance of senior unsecured notes	500,000	—	—
NPI payable	—	20,348	16,583
Net cash provided by financing activities	$636,826	$8,248	$81,583
NET CHANGE IN CASH	$43,058	$(37,998)	$41,166
CASH AT BEGINNING OF PERIOD	$13,234	$51,232	$10,066
CASH AT END OF PERIOD	$56,292	$13,234	$51,232
SUPPLEMENTAL CASH FLOW INFORMATION			

Cash paid for interest	$3,897	$3,373	$3,420
Cash paid for taxes	$3,800	$—	$—
NON-CASH ACTIVITIES			
Asset retirement obligation acquired	$2,147	$644	$—
Common stock issued for oil and gas properties	$677,402	$—	$—
Deferred tax liabilities recorded for oil and gas property acquisitions	$199,389	$—	$—
Elimination of NPI payable	$36,931	$—	$—
Change in accrued capital expenditures	$41,573	$4,921	$154

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 ultimately 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, development and operation of oil and natural gas properties. Until our initial public offering ("IPO") in January 2014 as described below, affiliates of NGP owned over 90% of RSP LLC's outstanding equity.

Rising Star Energy Development Co., L.L.C., a Delaware limited liability company (“Rising Star”), was formed in April 2006 and is engaged primarily in the acquisition, development and operation of oil and natural gas properties. Rising Star is wholly owned by Rising Star Energy Holdings Company, L.P. (“Rising Star LP”), which is managed by its general partner, Rising Star Energy GP, L.L.C. (“Rising Star GP”). An affiliate of NGP owns over 90% of the membership interests in Rising Star GP and over 80% of the limited partnership interests in Rising Star LP. Rising Star LP’s sole material assets are its interests in Rising Star and its interests in Rising Star Energy Operating Co., L.L.C., which has not conducted any operations for the past several years.

Until the IPO, all power and authority to control the core functions of RSP LLC and Rising Star (collectively, the “Predecessor”) were controlled by affiliates of NGP. The historical results of RSP LLC and Rising Star were combined for all periods presented prior to the IPO date.

On January 17, 2014, RSP Inc. sold 23 million shares at $19.50 per share to the public in an IPO and began trading on the New York Stock Exchange under the ticker symbol "RSPP." Of the 23 million shares, 9.2 million were shares sold by RSP Inc., resulting in approximately $180 million of gross proceeds ($163 million in net proceeds), which were used to fully repay the Company’s $70 million term loan, repay outstanding borrowings of $56 million under its revolving credit facility, make cash payments to certain existing investors as partial consideration for the properties contributed to the Company by such persons, pay cash bonuses to certain of the Company’s employees in connection with the successful completion of the IPO, and fund a portion of its capital expenditure plan. The remaining 13.8 million shares sold in the IPO were sold by selling stockholders, and the Company did not receive any proceeds from the sale of those shares. On August 12, 2014, RSP Inc. completed an underwritten public offering of 11.5 million shares of RSP Inc. common stock at $25.65 per share; the Company sold 4.8 million primary shares in the offering raising $118 million in net proceeds.

In connection with the IPO, several transactions occurred that changed the structure and scope of the Company:

- Corporate Reorganization: RSP LLC was contributed to RSP Permian Holdco, L.L.C., a newly formed limited liability company, which contributed all of its interests in RSP LLC to RSP Inc. in exchange for shares of RSP Inc.’s common stock, an assignment of RSP LLC’s pro rata share of an escrow related to the Resolute Sale (as defined and described in Note 3) and cash. As a result of this reorganization, RSP LLC became a wholly owned subsidiary of RSP Inc.
- The Rising Star Acquisition: RSP Inc. acquired from Rising Star, working interests in certain acreage and wells in the Permian Basin in which RSP LLC already had working interests in exchange for shares of RSP Inc.’s common stock and cash.
- The Collins and Wallace Contributions: Ted Collins, Jr. (“Collins”), Wallace Family Partnership, LP (“Wallace LP”) and Collins & Wallace Holdings, LLC, a newly formed entity that is jointly owned by Collins and Wallace LP, contributed certain working interests in the Permian Basin in which RSP LLC already had working interests in

exchange for shares of RSP Inc.'s common stock and, in the case of Collins and Wallace LP, cash (such contributions, the "Collins and Wallace Contributions"). See Note 3 for additional information.

•The Pecos Contribution: Pecos Energy Partners, L.P. ("Pecos"), an entity owned by certain members of the Company's management team, contributed certain working interests in acreage and wells in the Permian Basin in which RSP LLC already had a working interest in exchange for shares of RSP Inc.'s common stock.

•The ACTOIL NPI Repurchase: ACTOIL, LLC ("ACTOIL"), the owner of 25% net profits interests ("NPI") in substantially all of RSP LLC's oil and natural gas properties taken as a whole, contributed their 25% NPIs in exchange for shares of RSP Inc.'s common stock (such contribution, the "ACTOIL NPI Repurchase"). See Note 3 for more information.

Basis of Presentation

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These financial statements have been prepared by the Company pursuant to the rules and regulations of the SEC. They reflect all adjustments that are, in the opinion of management, necessary for a fair statement of the results. All such adjustments are of a normal recurring nature. Transfers of a business between entities under common control are accounted for as if the transfer occurred at the beginning of the period, and prior years are retrospectively adjusted to furnish comparative information. The historical results of RSP LLC and Rising Star have been consolidated for all periods presented prior to the IPO date.

Subsequent Events

The Company has evaluated subsequent events of its consolidated financial statements. There were no material subsequent events requiring additional disclosure 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 and the fair value of incentive unit compensation also require significant assumptions. It is possible that these estimates could be revised at future dates and these revisions could be material. 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.

Reclassifications

Certain reclassifications have been made to prior periods to conform to current period presentation.

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.

Derivative and Other Financial Instruments

The Company uses derivative financial instruments to reduce exposure to fluctuations in the prices of oil. These derivative transactions are generally in the form of collars, swaps and puts. In addition, the Company has previously entered into interest rate derivative contracts to minimize the effects of fluctuations in interest rates.

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.

The Company’s derivative instruments were not designated as hedges for accounting purposes for any of the periods presented. Accordingly, the changes in fair value are recognized in the consolidated statements of operations in the period of change. Gains and losses on derivatives are included in cash flows from operating activities.

Accounts Receivable

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	As of December 31,	
	2014	2013
	(In thousands)	
Sale of oil and natural gas and related products	$24,059	$15,618
Joint interest owners	10,400	10,728
Derivatives - settled, but uncollected	5,977	—
Total accounts receivable	$40,436	$26,346

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 and receivables related to joint interest billings 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 Company has not provided an allowance for doubtful accounts based on management’s expectations that all material receivables at year-end will be collected. The need for an allowance is determined based upon reviews of individual accounts, historical losses, existing economic conditions and other pertinent factors. No bad debt expense was recorded for the years ended December 31, 2014, 2013 or 2012.

Transactions with Related Parties

The Company's accounts receivable from related parties as of December 31, 2013 was $3.7 million and was owed by Wallace LP. Prior to the IPO, Collins, Wallace LP and Collins & Wallace Holdings, LLC had non-operated working interests in substantially all of the oil and natural gas assets that the Company operates. As of December 31, 2014, all related party receivable balances have been collected and no amounts remain outstanding.

In August 2014, the Company acquired from Pecos working interests in certain acreage and wells in Glasscock County, Texas for $4.5 million associated with the series of acquisitions in the amount of $257 million as further described in the recent acquisitions section of Note 3 - Acquisitions and Sales of Oil and Natural Gas Property Interests.

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 capitalizes interest on expenditures while activities are in progress to bring the assets to their intended use for significant exploration and development projects that last more than six months. The Company did not capitalize any interest in the years ended December 31, 2014, 2013 or 2012, as no projects lasted more 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. Unproved properties are assessed at least annually for possible impairment.

Capitalized acquisition costs attributable to proved oil and natural gas properties and leasehold costs are depleted on a field basis based on proved reserves using the unit-of-production method. Capitalized exploration well costs and development costs, including AROs, are depleted on a field basis, based on proved developed reserves. Depletion expense for oil and natural gas producing property was $87.2 million, $46.9 million, and $48.0 million, for the years ended December 31, 2014, 2013 and 2012, respectively. Depletion expense is included in depreciation, depletion and amortization in the accompanying consolidated statements of operations.

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The Company's oil and natural gas properties as of December 31, 2014 and December 31, 2013 consisted of the following:

	As of December 31,	
	2014	2013
	(In thousands)	
Proved oil and natural gas properties	$1,585,125	$562,019
Unproved oil and natural gas properties	655,678	33,467
Total oil and natural gas properties	2,240,803	595,486
Less: accumulated depletion and impairment	(171,046)	(88,514)
Total oil and natural gas properties, net	$2,069,757	$506,972

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, 2014 and 2013, 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 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. Unproved properties are assessed at least annually to determine whether they have been impaired. An impairment allowance is provided on an unproved property when the Company determines that the property will not be developed. 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. For the year ended December 31, 2014, impairment expense for unproved property was $4.3 million, which primarily related to an expectation that certain leasehold interests would expire and not be renewed. No impairment of unproved property was recorded for the years ended December 31, 2013 or 2012.

Natural gas volumes are converted to Boe at the rate of six Mcf of natural gas to one Bbl of oil. This convention is not an equivalent price basis and there may be a large difference in value between an equivalent volume of oil versus an equivalent volume of natural gas. NGL volumes are stated in barrels.

Other Property and Equipment

Other property and equipment includes service wells, computer equipment and software, telecommunications equipment, and furniture and fixtures. These items are recorded at cost, or fair value if acquired through a business acquisition, and are depreciated using straight-line methods based on expected lives of the individual assets or group of assets ranging from 5 to 39 years. Depreciation expense related to such assets for the years ended December 31, 2014, 2013 and 2012 was $0.9 million, $0.3 million and $0.3 million, respectively, and is included in depreciation, depletion and amortization in the accompanying consolidated statements of operations.

Investment in Unconsolidated Subsidiary

In October 2014, the Company invested $0.6 million which is included in "Other long-term assets" on the accompanying consolidated balance sheet and has committed to invest $5 million in the aggregate. This entity will develop, own and operate an integrated water management system to gather, store, process, treat, distribute and dispose of water on behalf of exploration and production companies operating in Midland, Martin, Andrews, and other counties in Texas approved by the board of this entity. Under the terms of the agreement, the Company owns a minority interest and will account for this investment using the equity method of accounting.

Restricted Cash

Restricted cash as of December 31, 2014 and 2013 consisted of certificates of deposit that mature in periods through 2017.

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Deferred Loan Costs

Deferred loan costs are stated at cost, net of amortization, which is computed using the effective interest method over the life of the loan. Deferred loan costs of $15.1 million and $2.2 million as of December 31, 2014 and 2013, respectively, net of accumulated amortization, are included in other long-term assets in the accompanying consolidated balance sheets. Amortization of deferred loan costs of $1.2 million, $1.7 million and $0.5 million was recorded for the years ended December 31, 2014, 2013 and 2012, respectively.

Asset Retirement Obligations

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.

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 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 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 consisted of the following for the period indicated:

	Year Ended December 31,	
	2014	2013
	(In thousands)	
Asset retirement obligation at beginning of period	$2,584	$2,716
Liabilities incurred or assumed	2,147	644
Liabilities settled	—	(897)
Accretion expense	142	121
Asset retirement obligation at end of period	$4,873	$2,584

Income Taxes

RSP LLC was organized as a limited liability company and treated as a flow-through entity for federal income tax purposes. As such, taxable income and any related tax credits were passed through to its members and are included in their tax returns even though such net taxable income or tax credits may not have actually been distributed. Accordingly, provision for federal and state corporate income taxes has been made only for the operations of RSP Inc.

from January 23, 2014 through December 31, 2014 in the accompanying consolidated financial statements. Deferred income taxes are provided to reflect the future tax consequences or benefits of differences between the tax basis of assets and liabilities and their reported amounts in the financial statements using enacted tax rates. Upon 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.

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The following is an analysis of the Company's consolidated income tax expense:

	Year Ended December 31,		
	2014	2013	2012
	(In thousands)		
Current	$4,338	$68	$(339)
Deferred	153,468	2,194	—
Income Tax Expense (Benefit)	$157,806	$2,262	$(339)

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, 2014, the Company did not have any accrued liability for uncertain tax positions and does not anticipate recognition of any significant liabilities for uncertain tax positions during the next 12 months.

The Company's U.S. federal income tax returns and Texas franchise tax returns for 2010 and beyond remain subject to examination by the taxing authorities. No other jurisdiction's returns are significant to the Company's financial position.

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 January 2015, the Financial Accounting Standards Board ("FASB") issued ASU 2015-01, "Income Statement - Extraordinary and Unusual Items (Subtopic 225-20)," which eliminates the concept of extraordinary items in US GAAP. An entity is required to apply ASU 2015-01 for annual and interim reporting periods beginning after December 15, 2015. An entity may apply ASU 2015-01 prospectively or retrospectively for all periods presented in the financial statements. The Company does not expect the impact of its pending adoption of this guidance will have a material effect 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. An entity is required to apply ASU 2014-09 for annual and interim reporting periods beginning after December 15, 2016. 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 is evaluating the impact that this new guidance will have on its consolidated financial statements.

NOTE 3—ACQUISITIONS AND SALES OF OIL AND NATURAL GAS PROPERTY INTERESTS

Pro Forma Results

The Company's summary pro forma results for the twelve months ended December 31, 2013 were derived from the actual results of the Company's accounting predecessor, which reflects the combined results of RSP LLC and Rising Star, and have been adjusted to reflect the Collins and Wallace Contributions and the ACTOIL NPI Repurchase, both of which were completed in connection with the IPO on January 23, 2014, as if such transactions had occurred on January 1, 2013. Additionally, the pro forma results for the 2013 periods include the estimated activity associated with the Spanish Trail Acquisition (as defined below), which was completed in September 2013, and the Resolute Sale, which was completed in March 2013, as if each of these transactions had occurred on January 1, 2013.

Our pro forma results for the twelve months ended December 31, 2014 were derived from our actual results and have been adjusted to reflect the Collins and Wallace Contributions and the ACTOIL NPI Repurchase, both of which were completed in connection with the IPO on January 23, 2014, as if such transactions had occurred on January 1, 2013.

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 IPO.

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.

	Year Ended December 31, 2014		Year Ended December 31, 2013	
	Actual	Pro Forma	Actual	Pro Forma
	(In thousands)		(In thousands)	
Revenues	$281,925	$286,910	$123,042	$197,309
Net income	$2,498	$2,743	$62,738	$73,228

Recent Acquisitions

During the first quarter of 2014, the Company acquired additional acreage prospective for horizontal development in Martin, Glasscock and Dawson counties for an aggregate purchase price of approximately $79 million in three separate transactions with approximately $45 million recorded as proved oil and natural gas properties. The transactions were financed with borrowings under the Company's revolving credit facility.

In August 2014, in separate transactions with multiple sellers, the Company acquired predominantly undeveloped acreage and certain oil and gas producing properties located in Glasscock County, Texas, for an aggregate purchase price of $257 million, with approximately $124 million recorded as proved oil and natural gas properties. The transactions were financed with borrowings under the Company's revolving credit facility, and the amount of historical revenues and cash flow were immaterial compared to our historical results.

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Collins and Wallace Contributions

Collins, Wallace LP and Collins & Wallace Holdings, LLC contributed to RSP Inc. certain working interests in the Permian Basin in which RSP LLC already had working interests. In exchange, (i) Collins received shares of RSP Inc.'s common stock and the right to receive approximately $1.6 million in cash, (ii) Wallace LP received shares of RSP Inc.'s common stock and the right to receive $0.6 million in cash, and (iii) Collins & Wallace Holdings, LLC received shares of RSP Inc.'s common stock. The Collins and Wallace Contributions occurred in connection with the IPO.

These contributed working interests consist of the following: (i) Collins' non-operated working interest in substantially all of the oil and natural gas properties that RSP LLC owned prior to the Spanish Trail Acquisition; (ii) Wallace LP's non-operated working interest in substantially all of the oil and natural gas properties that RSP LLC owned prior to the Spanish Trail Acquisition; and (iii) Collins & Wallace Holdings, LLC's non-operated working interest in the Spanish Trail Assets (as defined below).

A summary of the consideration transferred and the fair value of assets and liabilities acquired in connection with the Collins and Wallace Contributions is as follows (in thousands):

Value of the 22,023,654 shares of the Company's common stock issued in the Collins and Wallace Contributions	$429,461	
Cash paid in the Collins and Wallace Contributions	2,219	
Total consideration for the assets contributed in the Collins and Wallace Contributions	$431,680	
Fair value of oil and natural gas properties	$653,431	
Asset retirement obligation	(1,063	)
Deferred tax liability*	(215,609	)
Total net assets acquired **	$436,759	

* Amount represents the estimated book to tax difference in oil and natural gas properties as of the acquisition date on a tax-effected basis of approximately 36%.
** Approximately 56% of acquired acreage was unproved.

ACTOIL NPI Repurchase

In July 2011, RSP LLC sold to ACTOIL a 25% NPI in substantially all of its oil and natural gas properties taken as a whole. In addition, RSP LLC sold to ACTOIL a 25% NPI in the oil and natural gas properties acquired by RSP LLC in the Spanish Trail Acquisition. In connection with the IPO, ACTOIL contributed both 25% NPIs to the Company in exchange for shares of RSP Inc.'s common stock. The 25% NPIs exchanged for shares in the Company had a value of approximately $210.9 million and were accounted for as asset acquisitions.

The Company's predecessor's sale of properties to Resolute Natural Resources Southwest LLC ("Resolute") in December 2012 and March 2013 resulted in ACTOIL earning cash proceeds through its NPI in the properties sold. ACTOIL reduced its NPI account cumulative deficit balance with these proceeds, rather than receiving a cash distribution. As such, the Company's predecessor applied the NPI proceeds dollar-for-dollar to reduce the NPI deficit balance and recorded the amount as a long-term NPI payable on its balance sheet. This amount was eliminated upon ACTOIL contributing its NPI in exchange for common shares in connection with the IPO.

A summary of the consideration transferred and the assets acquired and liabilities acquired in connection with the ACTOIL NPI Repurchase is as follows (in thousands):

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Value of the 10,816,626 shares of the Company's common stock issued in the ACTOIL NPI Repurchase	$210,924
Elimination of NPI payable	(36,931)
Total consideration for the assets contributed in the ACTOIL NPI Repurchase	$173,993
Oil and natural gas properties cost	$157,382
Asset retirement obligation	(639)
Deferred tax asset*	17,250
Total net assets acquired**	$173,993

* Amount represents the estimated book to tax difference in oil and natural gas properties as of the acquisition date on a tax-effected basis of approximately 36%.
** Approximately 56% of acquired acreage was unproved.

Spanish Trail Acquisition

On September 10, 2013, RSP LLC acquired additional working interests in certain of its existing properties in the Permian Basin (the "Spanish Trail Acquisition") from Summit Petroleum, LLC ("Summit") and EGL Resources, Inc. ("EGL"). The aggregate purchase price for the assets acquired in the Spanish Trail Acquisition (the "Spanish Trail Assets") agreed to by RSP LLC and the sellers was $155 million.

Subsequent to the signing of the purchase agreement and prior to the closing of the Spanish Trail Acquisition, Collins and Wallace LP, non-operating working interest owners in the Spanish Trail Assets, exercised preferential purchase rights granted under a joint operating agreement among the working interest owners in the Spanish Trail Assets. The preferential purchase rights gave Collins and Wallace LP the right to purchase a portion of the working interests sold by Summit and EGL. Collins and Wallace LP completed this acquisition through Collins & Wallace Holdings, LLC, a newly formed entity that is jointly owned by Collins and Wallace LP, which contributed these acquired assets to RSP Inc. in exchange for shares of RSP Inc.'s common stock in connection with the IPO. The exercise of the preferential purchase rights reduced RSP LLC's purchase price from $155 million to $121 million.

Simultaneously with the closing of the Spanish Trail Acquisition, pursuant to ACTOIL's exercise of a right of first refusal granted by RSP LLC in the agreement that governs ACTOIL's NPI investment, RSP LLC conveyed a 25% NPI in the Spanish Trail Assets taken as a whole, excluding the portion acquired by Collins & Wallace Holdings, LLC, to ACTOIL in exchange for cash equal to 25% of RSP LLC's $121 million purchase price. The exercise of the right of first refusal by ACTOIL and issuance of the 25% NPI reduced RSP LLC's purchase price from $121 million to $91 million with a majority of that amount recorded to proved property.

RSP LLC allocated the net purchase price to the oil and natural gas properties acquired and asset retirement obligation assumed as follows (in thousands):

Net purchase price	$120,521
25% NPI Sale to ACTOIL	(30,131)
Oil and natural gas properties acquired	$90,390
Asset retirement obligation assumed	296
Proved oil and natural gas properties	$90,686

The Spanish Trail Acquisition was funded with a $70 million term loan, borrowings under the Company's revolving credit facility (described below in Note 6) and the issuance of the NPI to ACTOIL described above.

Resolute Sale

Effective October 1, 2012, RSP LLC, ACTOIL and other minority non-operating working interest owners entered into a Purchase, Sale, and Option Agreement (“PSA”) to sell an undivided 32.35% interest in certain assets for an aggregate purchase price of $110 million to Resolute (the “Resolute Sale”). The Company’s share of the purchase price was $69 million and was recorded as a reduction to the basis of the underlying oil and natural gas properties. To the extent that the proceeds received exceeded the cost basis of the oil and natural gas properties, the Company recorded a gain on the sale. In addition, RSP LLC

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and the other sellers sold Resolute an option (the “Option”) for $5 million, $2.4 million of which was the Company’s share. The Option allowed Resolute to acquire the remaining 67.65% interest in these certain assets. The Option was non-refundable and only entitled Resolute to a limited time period during which it could exercise the right to acquire the remaining interest in these certain assets, and therefore the Option fee was included in the consideration transferred in computing the gain on disposition of the assets described above. The Company recorded a gain in connection with the sale of the 32.35% interest in these assets and the option fee in the amount of $6.7 million for the year ended December 31, 2012.

In March 2013, Resolute exercised the right to acquire the 67.65% remaining interest in these assets from RSP LLC, ACTOIL and other working interest owners for an additional purchase price of approximately $230.0 million. RSP LLC’s share of the purchase price was $144.2 million. In connection with the transaction closing in March 2013, RSP LLC recorded a gain of approximately $6 million.

The PSA contained customary closing conditions and included a $5 million title and environmental escrow (net to RSP LLC) and an $11 million indemnity escrow (net to RSP LLC) which were held back from the initial purchase price to provide for these contingencies. Amounts held in escrow for potential indemnity matters were not initially considered in the computation of the gain in connection with the sale of these certain assets because the Company could not reasonably estimate the potential outcome of any such matters at the time of the initial closing of the transaction.

Subsequent to the initial closing, in October 2013, RSP LLC received the first two scheduled escrow payments under the terms of the PSA totaling approximately $12 million. The receipt of these funds substantially resolved any uncertainty associated with the ability to collect the remaining portion of the amounts held in escrow and, therefore, the Company recorded the gain associated with all funds received and the remaining escrow amounts not yet received as collectability of such amounts was deemed probable. For the twelve months ended December 31, 2013, the total gain recognized on the Resolute Sale was approximately $22.7 million.

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 over-the-counter (“OTC”) swaps and collars. 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 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.

Each collar transaction has an established price floor and ceiling. 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.

The following table summarizes all open positions as of December 31, 2014:

	Contracts Maturing During 2015
Crude Oil Swaps:	
Notional volume (Bbl)	120,000
Weighted average price ($/Bbl)(1)	$92.60
Crude Oil Collars:	
Notional volume (Bbl)	2,337,000
Weighted average ceiling price ($/Bbl)(1)	$94.64
Weighted average floor price ($/Bbl)(1)	$86.42

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(1) The crude oil derivative contracts are settled based on the month's average daily NYMEX price of West Texas Intermediate Light Sweet Crude.

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. 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 December 31, 2014 (In thousands)	December 31, 2013	Liabilities December 31, 2014	December 31, 2013
Derivative Instruments:				
Current amounts				
Commodity contracts	$76,990	$ 671	$(1,320)	$ (1,562)
Noncurrent amounts				
Commodity contracts	—	1,078	—	(43)
Total derivative instruments	$76,990	$ 1,749	$(1,320)	$ (1,605)

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

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

	Year Ended December 31, 2014 (In thousands)	2013	2012
Gain (loss) on derivative instruments:			
Commodity derivative instruments	$81,470	$(2,583)	$(408)
Interest rate derivative instruments	—	(24)	(388)
Total	$81,470	$(2,607)	$(796)

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 (In thousands)	Netting Adjustments(a)	Net Amount
December 31, 2014			
Derivative instrument assets with right of offset or master netting agreements	$76,990	$ (1,320)	$75,670
Derivative instrument liabilities with right of offset or master netting agreements	$(1,320)	$ 1,320	$—
December 31, 2013			
	$1,749	$ (1,332)	$417

Derivative instrument assets with right of offset or master netting agreements			
Derivative instrument liabilities with right of offset or master netting agreements	$(1,605)	$ 1,332	$(273)

(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.

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Credit-Risk Related Contingent Features in Derivatives

None of the Company’s derivative instruments contains credit-risk related contingent features. No amounts of collateral were posted by the Company related to net positions as of December 31, 2014 and December 31, 2013.

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. The book value of the Company's senior notes approximates the fair value as the current trading value of the notes approximates par value. If the Company recorded the 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. The fair value of derivative financial instruments is determined utilizing industry standard models using assumptions and inputs 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. These inputs 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.

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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, 2014:				
Commodity derivative instruments	$—	$75,670	$—	$75,670
Total	$—	$75,670	$—	$75,670

	Level 1	Level 2	Level 3	Total fair value
	(In thousands)			
As of December 31, 2013:				
Commodity derivative instruments	$—	$144	$—	$144
Total	$—	$144	$—	$144

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

Reclassifications of fair value between Level 1, Level 2 and Level 3 of the fair value hierarchy, if applicable, are made at the end of each quarter. There were no transfers between Level 1, Level 2 or Level 3 during the years ended December 31, 2014, 2013, and 2012.

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:

	As of December 31,	
	2014	2013
	(In millions)	

Term loan	$—	$70.0
Revolving credit facility	—	58.2
6.625% Senior notes	500.0	—
Total long-term debt	$500.0	$128.2

Credit Agreement

On September 10, 2013, in conjunction with the Spanish Trail Acquisition, the Company amended and restated its credit agreement, dated December 15, 2010, with Comerica Bank, as administrative agent providing for a revolving credit facility of up to $500 million, and expanded its syndicated bank group to 11 lenders. In addition, the Company entered into a new term loan in the amount of $70 million to partially finance the Spanish Trail Acquisition. On January 23, 2014, the Company repaid the term loan in full, and has no contractual obligations with respect to the term loan.

On June 9, 2014, the borrowing base under the revolving credit facility was increased from $300 million to $375 million as a result of the semiannual borrowing base redetermination under the revolving credit facility.

In conjunction with the closing of our acquisitions in Glasscock County, on August 29, 2014, the Company amended the revolving credit facility to increase the borrowing base to $500 million, to increase the lenders' maximum facility commitments to $1.0 billion, to extend the maturity date to August 29, 2019 and to allow the Company to issue the senior unsecured notes described below. In connection with the Company's issuance of its senior unsecured notes, on September 24, 2014, the Company amended the revolving credit facility to permit the Company to make payment to the Company to enable it to pay principal, premium (if any) and interest on the unsecured notes provided no default has occurred and to allow RSP LLC to guaranty the unsecured notes.

The Company's revolving credit facility requires it to maintain the following three 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 4.5 to 1.0,
•a senior secured leverage ratio, which is the ratio of the sum of all the Company's debt that is (i) secured and (ii) not subordinated to obligations under the revolving credit facility to the consolidated EBITDAX (as defined in the credit agreement) for the four fiscal quarters then ended, of not greater than 3.5 to 1.0.

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, 2014.

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 in Eurodollars or at the alternate 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 100 to 200 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 reference rate; (ii) the federal funds effective rate plus 100 basis points; and (iii) the adjusted LIBOR rate plus 100 basis points, plus an applicable margin ranging from 0 to 100 basis points, depending on the percentage of its borrowing base utilized, plus a facility fee of 0.50% charged on the borrowing base amount. At December 31, 2014, the prime borrowing rate of interest under the Company’s revolving credit facility was 3.25%. RSP LLC may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs. As of December 31, 2014, the revolving credit facility has a margin of 1.00% to 2.00% plus LIBOR, plus a facility fee of 0.50% charged on the borrowing base amount.

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. The borrowing base under the Company’s amended and restated credit agreement is $500 million as of December 31, 2014, with lender commitments of $1 billion. The maturity date of the Company’s revolving credit facility is August 29, 2019.

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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. 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 borrowing 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 April 1 and October 1 and commences on April 1, 2015. 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 notes, which is included in "Other long-term assets" 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. The Company was in compliance with the provisions of the indenture governing the senior unsecured notes as of December 31, 2014.

NOTE 7—NET PROFITS INTEREST

In July 2011, RSP LLC entered into a $175.0 million financing agreement to convey a 25% net profits interest ("NPI") to ACTOIL. The NPI conveys 25% of the oil and natural gas sales less associated direct capital expenditures and lease operating expenses from substantially all the oil and natural gas properties held by RSP LLC effective January 1, 2011. RSP maintains a separate net profits interest account ("NPI Account") maintained on a cash basis, as defined in the agreement governing the NPI.

The calculation to determine if amounts were to be distributed to ACTOIL for its interest was determined on a quarterly basis by RSP LLC. ACTOIL did not fund its proportionate share of direct capital expenditures or lease operating expenses as the expenses were funded by the Company and reimbursed through the NPI calculation. When the cumulative oil and natural gas sales, net of associated direct capital expenditures and lease operating expenses attributable to the NPI was a negative number, then the distribution was zero for such calendar quarter and such cumulative negative amount was carried forward. When the cumulative NPI calculation became a positive number at the end of a calendar quarter, a distribution would be made to ACTOIL for its share of net profits. If the NPI Account had a deficit balance at the end of a calendar quarter, ACTOIL incurred interest to RSP LLC on the cumulative deficit balance at varying annual rates depending on the amount of the deficit balance. This interest was added to the cumulative deficit balance.

In December 2012, RSP, ACTOIL and other minority non-operating working interest owners sold an undivided 32.35% interest in certain assets for an aggregate purchase price of $110.0 million to Resolute. In addition, RSP and the other sellers sold Resolute the Option for $5.0 million as described in Note 3. ACTOIL's share of the proceeds, after escrowed items, was approximately $15.8 million. ACTOIL used these proceeds, along with subsequent escrow releases, to reduce the cumulative deficit balance of the NPI Account. The proceeds were applied dollar for dollar to reduce the NPI deficit balance as of the date of the sale and recorded as a long-term NPI payable.

As described in Note 3, in March 2013, Resolute exercised the right to acquire the 67.65% remaining interest in these assets from RSP, ACTOIL and other working interest owners for an additional purchase price before adjustments of $230.0 million. ACTOIL's share of the proceeds, after escrowed items and adjustments, was approximately $31.8 million. ACTOIL used $21.1 million of these proceeds to first reduce the cumulative deficit balance of the NPI Account to zero. The Predecessor recorded the $21.1 million proceeds as a long-term NPI payable in the accompanying balance sheet. The remaining proceeds of $10.7 million were distributed to ACTOIL.

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In January 2014, ACTOIL contributed their 25% NPI in exchange for shares of RSP Inc.'s common stock. See Note 1 for additional information.

NOTE 8—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,					
	2014		2013		2012	
Shell Trading (US) Company	31	%	40	%	3	%
Enterprise Crude Oil LLC	24	%	14	%	—	%
Diamondback E&P, LLC	14	%	11	%	2	%
Coronado Midstream, LLC	6	%	8	%	11	%
Plains Marketing, L.P.	—	%	13	%	76	%
Permian Transport & Trading	21	%	—	%	—	%

Management believes that there are potential alternative purchasers and that it may be 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 9—EQUITY BASED COMPENSATION

Equity-based compensation expense, which is recorded in General and administrative expenses, was $20.2 million for the twelve months ended December 31, 2014. Equity-based compensation expense includes certain costs which are non-recurring; expense for restricted shares which were issued as a bonus related to our IPO ($2.8 million) along with expense related to incentive units ($14.7 million) as discussed below.

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 these awards was $4.7 million for the year ended December 31, 2014. Included in the before mentioned amount is $2.8 million of expense related to restricted shares issued as a bonus related to our IPO. 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, 2014, the Company had unrecognized compensation expense of $6.9 million related to restricted stock awards which is expected to be recognized over a weighted average period of 1.6 years.

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The following table represents restricted stock award activity for the twelve months ended December 31, 2014:

	Shares	Weighted Average Fair Value
Restricted shares outstanding, beginning of period	—	$—
Restricted shares granted	489,544	$23.69
Restricted shares canceled	(11,777)	$23.03
Restricted shares outstanding, end of period	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.

Equity-based compensation for these awards was $0.8 million for the twelve months ended December 31, 2014. The compensation expense for the market condition is based on a grant date valuation of $28.14 per share using a Monte-Carlo simulation. The unrecognized compensation expense related to these shares is approximately $3.0 million as of December 31, 2014 and is expected to be recognized over the next 2.17 years. The payout level is calculated based on actual performance achieved during the performance period compared to a defined peer group.

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, consisting of Tier I, Tier I A, Tier II, Tier III and Tier IV units. The incentive units were intended to be compensation for services rendered to the Company. All incentive units, whether vested or not, are forfeited if payouts are not achieved by a specified date. Tier I and Tier I A incentive units vest ratably over three years but are subject to forfeiture if payout is not achieved. Tier I and Tier I A payout is realized upon the return of members' invested capital and a specified rate of return. Tiers II, III and IV incentive units vest only upon the achievement of certain distribution thresholds for each such Tier and each Tier of the incentive units is subject to forfeiture if the applicable required payouts are not achieved. In addition, vested and unvested units will be forfeited if an incentive unit holder's employment is terminated for cause or if the unitholder voluntarily terminates his or her employment.

In connection with the IPO, the incentive units of RSP LLC became incentive units in RSP Permian Holdco, L.L.C. and therefore based upon distributions to members of RSP Permian Holdco, L.L.C. rather than members of RSP LLC. The terms and conditions of the profits interest awards remained substantially similar to the terms applicable to the incentive unit awards prior to the IPO, including the retention of existing vesting schedules.

The achievement of payout conditions is a performance condition that requires the Company to assess, at each reporting period, the probability that an event of payout will occur. Compensation cost is required to be recognized at such time that the payout terms are probable of being met. At the grant dates and subsequent reporting periods prior to the IPO, the Company did not deem as probable that such payouts would be achieved for any Tier of incentive units. At such time that the occurrence of the performance conditions associated with these incentive units are deemed probable, the Company will record a non-cash compensation expense based upon the grant date fair value of the incentive units that are probable of reaching payout as a result of reaching established distribution thresholds.

After successful completion of the IPO, the performance conditions associated with the Tier I, Tier I A and Tier II incentive units were deemed probable of reaching payout, while the performance conditions of the Tier III incentive units were deemed probable of reaching payout in the fourth quarter of 2014. In 2014, the Company recognized non-cash compensation expense of $14.7 million related to these incentive units. In December 2014, the incentive unit plan was terminated and all awards remaining under Tier I, Tier I A, Tier II, and Tier III incentive units were satisfied. These incentive units determined the stock allocation between management and NGP and had no dilutive impact, or cash impact, to RSP Permian, Inc.

NOTE 10—COMMITMENTS AND CONTINGENCIES

Legal Matters

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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, 2014 and 2013, the Company had no environmental matters requiring specific disclosure or requiring the recognition of a liability.

Leases

In October 2014, RSP LLC entered into a 60-month lease agreement for office space in Midland, Texas. In February 2014, RSP LLC entered into a 64-month lease agreement through May 2019 for office space in Dallas, Texas. In July 2014, RSP LLC entered into a 58-month lease agreement through May 2019 for additional office space in Dallas, Texas. Rent expense for the year ended December 31, 2014, 2013, and 2012 was $0.5 million, $0.2 million, and $0.2 million respectively.

Contractual Obligations

A summary of the Company's contractual obligations as of December 31, 2014 is provided in the following table (in thousands).

	Payments Due by Period For the Year Ended December 31,						
	2015	2016	2017	2018	2019	Thereafter	Total
	(In thousands)						
Revolving credit facility (1)	$—	$—	$—	$—	$—	$—	$—
6.625% Senior Notes (2)	—	—	—	—	—	500,000	500,000
Interest cost (3)	33,125	33,125	33,125	33,125	33,125	91,094	256,719
Drilling rig commitments (4)	34,296	19,440	1,645	—	—	—	55,381
Office and equipment leases	1,114	1,078	890	778	503	—	4,363
Asset retirement obligations (5)	—	—	—	—	—	4,873	4,873
Total	$68,535	$53,643	$35,660	$33,903	$33,628	$595,967	$821,336

(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.
(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

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revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environment.

NOTE 11—EARNINGS PER SHARE

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 net income for the year ended December 31, 2014, unvested restricted share awards were recognized in earnings per share calculations as they are dilutive. A reconciliation of the components of basic and diluted earnings per common share is presented in the table below:

	Year Ended December 31, 2014
Numerator:	
Net income available to stockholders	$2,498
Basic net income allocable to participating securities (1)	15
Income available to stockholders	$2,483
Denominator:	
Weighted average number of common shares outstanding - basic	71,898
Effect of dilutive securities:	
Restricted stock	—
Weighted average number of common shares outstanding - diluted	71,898
Net income per share:	
Basic	$0.03
Diluted	$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.

Pro Forma Earnings per Share

The Company computed a pro forma income tax provision as if the Company was subject to income taxes since January 1, 2014. 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, and excludes the non-recurring tax adjustment related to the corporate reorganization of the Company on January 23, 2014, as further described in Note 2 under "Income Taxes."

The Company's pro forma basic earnings per share amounts have been computed based on the weighted-average number of shares of common stock outstanding for the period, as if the common shares issued in the IPO were outstanding for the entire year. A reconciliation of the components of pro forma basic and diluted earnings per common share is presented in the table below:

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	Year Ended December 31, 2014
Numerator:	
Income before taxes, as reported	$160,304
Pro forma provision for income taxes	57,709
Pro forma net income available to stockholders	102,595
Basic net income allocable to participating securities	599
Pro forma net income available to stockholders	$101,996
Denominator:	
Weighted average number of common shares outstanding - basic	74,297
Effect of dilutive securities:	
Restricted stock	—
Weighted average number of common shares outstanding - diluted	74,297
Net income per share:	
Basic	$1.37
Diluted	$1.37

For the year ended December 31, 2014, our actual earnings per share was less than our pro forma earnings per share.

NOTE 12—INCOME TAXES

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.

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

	For the year ended December 31, 2014 (In thousands)
Current Income Tax Provision:	
Federal	$4,111
State	227
Total income tax provision	4,338
Deferred Income Tax Provision:	
Federal	$157,806
State	(227)
Federal alternative minimum tax	(4,111)
Total deferred income tax provision	153,468
Total Provision for Income Taxes	$157,806

Included in the deferred federal income tax provision above is $95.2 million related to the Company's change in tax status.

A reconciliation of the statutory federal income tax amount to the recorded expense is as follows:

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	For the year ended December 31, 2014 (In thousands)
Income tax expense at the federal statutory rate (35%)	$56,106
Income tax expense relating to change in tax status	95,162
State income tax expense, net of federal tax benefit	1,081
Non-deductible expenses	5,457
Provision for income taxes	$157,806

Prior to the Company's change in tax status in January 2014, income taxes did not significantly impact the results of operations for 2013 or 2012.

The components of the Company's deferred tax assets and liabilities as of December 31, 2014 are as follows:

	For the year ended December 31, 2014 (In thousands)	
Current:		
Deferred tax assets		
Derivative instruments	$—	
Other	1,519	
Total current deferred tax assets	1,519	
Deferred tax liabilities		
Derivative instruments	(26,949	)
Other	(359	)
Total current deferred tax liabilities	(27,308	)
Net current deferred tax assets	(25,789	)
Noncurrent:		
Deferred tax assets		
Net operating loss carryforwards (subject to 20 year expiration)	13,604	
Stock based compensation	1,943	
Alternative minimum tax credit carryforward	4,111	
Other	8	
Total noncurrent deferred tax assets	19,666	
Deferred tax liabilities		
Oil and natural gas properties and equipment	(348,928	)
Other	—	
Total noncurrent deferred tax liabilities	(348,928	)
Net noncurrent deferred tax liabilities	(329,262	)
Net deferred tax liabilities	$(355,051	)

Federal net operating loss carryforwards totaled $38.9 million at December 31, 2014.

NOTE 13 - SUPPLEMENTAL DISCLOSURE OF OIL AND NATURAL GAS OPERATIONS (UNAUDITED)

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

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

	2014	2013	2012
	(In thousands)		
Property acquisition costs:			
Proved (1)	$581,307	$86,958	$—
Unproved (1)	622,210	7,875	—
Exploration costs	16,762	—	—
Development costs	462,063	136,832	173,983
Total costs incurred	$1,682,342	$231,665	$173,983

(1) Includes non-cash additions in connection with the Company's IPO of approximately $842 million.
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:

	2014	2013
	(In thousands)	
Capitalized costs:		
Proved	$1,585,125	$562,019
Unproved	655,678	33,467
	$2,240,803	$595,486
Less accumulated depreciation, depletion, amortization and impairment	(171,046)	(88,514)
Net capitalized costs	$2,069,757	$506,972

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:

	2014	2013	2012
	(In thousands)		
Revenues:			
Oil and natural gas sales	$281,925	$123,042	$104,427
Costs:			
Lease operating expenses	34,704	14,113	12,693
Production and ad valorem taxes	19,758	8,326	7,575
Depreciation, depletion, and amortization	87,844	47,158	48,803
Asset retirement obligation accretion	142	121	115
Impairments	4,344	—	—
Exploration	3,854	551	161
Income tax expense (benefit)	157,806	2,262	(339)
Results of operations	$(26,527)	$50,511	$35,419

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Net Proved Oil and Natural Gas Reserves

The Company's proved oil and natural gas reserves as of December 31, 2014 were prepared by independent third party reserve engineers. The Predecessor's proved oil and natural gas reserves as of December 31, 2013 were prepared by independent third party reserve engineers, while the proved oil and gas reserves as of December 31, 2012 were prepared internally by management. In accordance with SEC regulations, reserves at December 31, 2014, 2013, and 2012 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.

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, 2014, 2013, and 2012 is as follows:

	Natural Gas (MMcf)	Oil (MBbls)	NGLs (MBbls)	MBoe
Proved developed and undeveloped reserves:				
As of January 1, 2012	92,416	33,371	—	48,774
Revisions of previous estimates	(57,872)	(15,353)	391	(24,608)
Extensions, discoveries and other additions	7,724	3,885	4,829	10,001
Production	(1,576)	(1,040)	(264)	(1,567)
As of December 31, 2012	40,692	20,863	4,956	32,600
Revisions of previous estimates	(2,628)	(941)	(2,465)	(3,844)
Extensions, discoveries and other additions	8,151	6,301	3,440	11,099
Divestitures	(14,687)	(5,156)	—	(7,603)
Purchases of minerals in place	5,872	3,832	1,232	6,044
Production	(1,597)	(1,167)	(250)	(1,683)
As of December 31, 2013	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
Proved developed reserves:				
December 31, 2012	17,847	7,730	1,723	12,427
December 31, 2013	14,396	9,533	2,703	14,636
December 31, 2014	35,921	27,716	8,221	41,924
Proved undeveloped reserves:				
December 31, 2012	22,845	13,133	3,233	20,173
December 31, 2013	21,407	14,199	4,210	21,977
December 31, 2014	56,501	41,557	13,518	64,492

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, 2014, the Company's positive revision of previous 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

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32,412 MBoe during 2014 were related to the Collins and Wallace contributions in connection with our IPO, and the Glasscock County acquisition.

For the year ended December 31, 2013, the Predecessor's negative revision of 3,844 MBoe of previous estimated quantities is primarily due to the change in estimates and type curves. Extensions, discoveries and other additions of 11,099 MBoe during the year ended December 31, 2013, 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 places of 6,044 MBoe during the year ended December 31, 2013 were directly related to the wells acquired through the Spanish Trail Acquisition. The divestiture of 7,603 MBoe during the year ended December 31, 2013 was due to the sale of the Western Assets.

For the year ended December 31, 2012, the Predecessor's negative revision of 24,608 MBoe of previous estimated quantities is primarily due to a change in development strategy to replace 20-acre proved vertical well locations with non-proved horizontal well locations. In addition, in 2012, the Predecessor switched to the recognition of three stream instead of two stream sales volumes, which resulted in a negative revision of natural gas reserves and a positive revision of NGL reserves. Extensions, discoveries and other additions of 10,001 MBoe during the year ended December 31, 2012, resulted primarily from the drilling of new wells during the year and from new proved undeveloped locations added during the year.

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, 2014, 2013, and 2012 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:

	2014	2013	2012
	(In thousands)		
Future cash inflows	$7,015,504	$2,547,566	$2,210,325
Future production costs	(2,025,302)	(727,939)	(655,720)
Future development costs	(1,182,981)	(378,695)	(362,876)
Future income tax expenses(1)	(1,154,808)	—	—
Future net cash flows	2,652,413	1,440,932	1,191,729
10% discount for estimated timing of cash flows	(1,776,282)	(890,217)	(737,556)
Standardized measure of discounted future net cash flows	$876,131	$550,715	$454,173

(1) Future net cash flows for 2013 and 2012 do not include the effects of income taxes on future revenues because the Predecessor was a limited liability company not subject to entity-level income taxation. Accordingly, no provision for federal or state corporate income taxes has been provided because taxable income was passed through to the Predecessor's equity holders. Following our change in tax status in January 2014, the Company is a subchapter

C corporation subject to U.S. federal and state income taxes. If the Predecessor had been subject to entity-level income taxation, the unaudited pro forma future income tax expense at December 31, 2013 and 2012 would have been $247.4 million and $155.7 million, respectively. The unaudited standardized measure at December 31, 2013 and 2012 would have been $303.3 million and $298.5 million, respectively.

In the foregoing determination of future cash inflows, sales prices used for gas and oil for December 31, 2014, 2013 and 2012 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

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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.

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

	2014	2013	2012
	(In thousands)		
Standardized measure of discounted future net cash flows, beginning of year	$550,715	$454,173	$854,424
Changes in the year resulting from:			
Sales, less production costs	(223,608)	(100,052)	(83,998)
Revisions of previous quantity estimates	20,892	(53,557)	(439,043)
Extensions, discoveries and other additions	646,855	157,086	84,149
Net change in prices and production costs	(74,081)	45,388	(133,485)
Changes in estimated future development costs	(7,858)	2,318	38,096
Previously estimated development costs incurred during the period	44,925	46,938	108,367
Divestiture of reserves	—	(151,440)	—
Purchases of minerals in place	366,106	94,751	—
Accretion of discount	55,072	45,417	85,442
Net change in income taxes	(441,506)	—	—
Timing differences and other	(61,380)	9,693	(59,779)
Standardized measure of discounted future net cash flows, end of year	$876,132	$550,715	$454,173

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 14 - QUARTERLY FINANCIAL DATA (Unaudited)

The Company's unaudited quarterly financial data for 2014 and 2013 is summarized below.

	2014			
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter

Revenues	$57,758	$74,062	$70,645	$79,458
Income from operations	12,657	30,576	33,160	16,512
Income tax (expense) benefit	(135,213)	(4,948)	(20,704)	3,060
Net income	$(127,530)	$8,226	$32,297	$89,503
Earnings per share:				
Basic and diluted	$(2.03)	$0.11	$0.43	$1.15

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In the first quarter of 2014, the Company established a $132 million provision for deferred income taxes related to the corporate reorganization, which occurred in connection with the IPO. This $132 million provision, related to our change in tax status, was then reduced by $37 million in the fourth quarter of 2014 as a result of correcting an error associated with the initial tax basis utilized in the computation of deferred tax liabilities associated with oil and gas properties. As a result of an evaluation of both quantitative and qualitative factors associated with this adjustment to deferred tax liabilities and the related income tax expense, the Company concluded that this correction was not material to any interim period that was affected. The $37 million was recorded as an adjustment of our fourth quarter income tax provision.

	2013 First Quarter	Second Quarter	Third Quarter	Fourth Quarter
Revenues	$24,655	$25,147	$36,860	$36,380
Income from operations	14,948	7,114	27,039	22,520
Income tax (expense) benefit	—	(68)	—	(2,194)
Net income	$12,866	$7,859	$24,037	$17,976
Pro forma information:				
Net income	$12,866	$7,859	$24,037	$17,976
Pro forma provision for income taxes (1)	4,632	2,829	8,653	6,472
Pro forma net income	8,234	5,030	15,384	11,504
Earnings per share:				
Basic and diluted	$0.26	$0.16	$0.48	$0.36

(1) Our predecessor, RSP Permian, L.L.C., 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 Code, and is subject to income taxes. The Company computed a pro forma income tax provision for 2013 as if RSP Permian, L.L.C. and Rising Star were subject to income taxes since January 1, 2013. For 2013 comparative purposes, we have included pro forma financial data to give effect to income taxes assuming the earnings of the RSP Permian, L.L.C. and Rising Star had been subject to federal income tax as a C-Corp. since inception. 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.

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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 3.2 of the Company’s Current Report on Form 8-K (File No. 001-36264) filed with the Commission on January 29, 2014).
4.1	Specimen Common Stock Certificate (incorporated by reference to Exhibit 4.1 of the Company's Registration Statement on Form S-1 (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 September 26, 2014, by and among the Company, RSP Permian, L.L.C. and Barclays Capital Inc. and RBC Capital Markets, LLC, as representatives of the initial purchasers named in therein (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 October 2, 2014).
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(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).
10.6(c)	

	Form of Restricted Stock Grant and Award Agreement (Performance Vesting) (incorporated by reference to the Company's Current Report on Form 8-K (File No. 001-36264) filed with the Commission on April 16, 2014).
10.7(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).
10.8(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).
10.90	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 buyer (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).
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, 2014.
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.

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(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.