RSP Permian, Inc.
Form 10-K
March 31, 2014
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark one)

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

For the fiscal year ended December 31, 2013

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 o No x

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 x

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 o No x

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 Registration S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x 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. o

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 x

As of June 28, 2013, the last business day of the registrant s most recently completed second quarter, the registrant s equity was not listed on a domestic exchange or over-the-counter market. The registrant s common stock began trading on the New York Stock Exchange on January 17, 2014.

The registrant had 72,500,000 shares of common stock outstanding at March 28, 2014.

Documents Incorporated by Reference: None

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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):

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

Bbls/d. Bbls per day.

Bcf. One billion cubic feet.

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.

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 natural gas. A natural gas containing insufficient quantities of hydrocarbons heavier than methane to allow their commercial extraction or to require their removal in order to render the gas suitable for fuel use.

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.

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.

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.

MBbls/d. One thousand Bbls per day.

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MBoe. One thousand Boe.

Mcf. One thousand cubic feet.

Mcf/d. One Mcf per day.

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.

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 and abandonment. 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 that, 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.

PUDs. Proved undeveloped reserves.

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.

Reserve life. A measure of the productive life of an oil or 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 for that year.

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.

RSP, the *Company*, *we*, *our*, *us* or like terms. RSP Permian, Inc. and its subsidiary, RSP Permian, L.L.C.

SEC. The United States Securities and Exchange Commission

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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.

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.

Wellbore. The hole drilled by the bit that is equipped for 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.

The terms analogous reservoir, development project, development well, economically producible, estimated ultimate recovery, exploratory proved developed reserves, proved reserves, proved undeveloped reserves, reliable technology, reserves and resources are defined by the

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 Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation Recent Events Corporate Formation Transactions.

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CAUTIONARY STATEMENT CONCERNING FORWARD-LOOKING STATEMENTS

Certain statements and information in this Report may constitute forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. The words believe, expect, anticipate, plan, intend, foresee, should, would, could or other simila are intended to identify forward-looking statements, which are generally not historical in nature. 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. Known material factors that could cause our actual results to differ from those in the forward-looking statements are those described in 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

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 and Ector. 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 it also maintains an office in Midland, Texas. The Company s telephone number is 214-252-2700, and its website is www.rsppermian.com.

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 (our 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. (Rising Star), L.L.C., Ted Collins, Jr. (Collins), 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, collectively the IPO Acquisitions and, together with the corporate reorganization, the IPO Transaction). See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Recent Events Corporate Formation Transactions for more information regarding the IPO Transactions.

Prior to the IPO Transactions, the Company had no material business operations. 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 the 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.

The information presented in the Business section has been presented on a pro forma basis to reflect the recent acquisition and formation transactions described in more detail below, unless otherwise noted.

Business Activities

Since our inception, we have participated in the drilling of over 300 vertical Wolfberry wells and served as the operator of over 180 of those wells. In late 2012, our primary focus shifted to drilling horizontal wells, which we believe provides more attractive returns on a majority of our acreage. Since initiating our horizontal drilling program, we have participated in the drilling and completion of 40 horizontal wells (17 of which we operate) as of December 31, 2013. Of these 40 total horizontal wells, 32 are Wolfberry B wells, one is a Wolfcamp D well, two are Middle Spraberry wells, four are Lower Spraberry wells and one is a Clearfork well. We believe that our properties provide horizontal opportunities in several other intervals, such as the Jo Mill, Dean, Wolfcamp A, Strawn, Atoka, Mississippian and Devonian formations. We target the multiple oil and natural gas producing stratigraphic horizons, or stacked pay zones, on our properties.

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We believe our vertical drilling program is a strong complement to our horizontal drilling program, and we plan to continue to drill vertical Wolfberry wells. In areas where we drill horizontal wells, vertical drilling, in concert with horizontal drilling, allows us to optimize 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 provides the most attractive returns. Further, vertical drilling enables us to hold our acreage through our continuous development program.

We are currently operating three horizontal rigs and one vertical rig. We expect to add an additional horizontal rig in the second quarter of 2014, two in 2015, one in 2016 and one in 2017, which will give us a total of eight operated horizontal rigs by the end of 2017. We expect to add one vertical rig in 2014 and two vertical rigs in 2015, which will give us a total of four operated vertical rigs by the end of 2015.

During 2013, we spent approximately $170 million to drill and complete operated wells, $37 million for our participation in the drilling and completion of non-operated wells and $9 million on infrastructure for a total of approximately $216 million. Our capital budget excludes expenditures related to acquisitions. Our 2014 capital budget for drilling, completion, recompletion and infrastructure is approximately $365 million. We intend to allocate our 2014 capital budget approximately as follows:

- $310 million, or 85%, for the drilling and completion of operated wells;
- $40 million, or 11%, for our participation in the drilling and completion of non-operated wells; and
- $15 million, or 4%, for infrastructure.

We expect that approximately 80% of our 2014 drilling and completion budget will be devoted to the drilling of horizontal wells. In particular, in 2014, we plan to drill 40 to 45 gross (35 to 40 net) operated horizontal wells in the Wolfcamp A, Wolfcamp B, Lower Spraberry, Middle Spraberry and Cline formations. We expect to participate in the drilling of 25 to 30 gross (four to six net) horizontal wells on our non-operated properties.

For the year ended December 31, 2013, our average net daily production was 7,293 Boe/d (approximately 70% oil, 14% natural gas and 16% NGLs), of which 15% was from horizontal well production and 85% was from vertical well production. As of December 31, 2013, we produced from 24 horizontal and 338 vertical wells and were the operator of approximately 95% of our net acreage.

As of December 31, 2013, our estimated proved oil and natural gas reserves were 53,883 MBoe based on a reserve report prepared by Ryder Scott Company, L.P. (Ryder Scott), our independent reserve engineer. Of these reserves, approximately 40% were classified as PDP. PUDs included in this estimate are from 290 vertical well locations and 23 horizontal well locations. As of December 31, 2013, these proved reserves were approximately 65% oil, 16% natural gas and 19% NGLs.

The following table provides summary information regarding our pro forma proved reserves as of December 31, 2013 and production for the year ended December 31, 2013.

	Estimated Total Proved Reserves							Average Net
	Oil (MMBbls)	Natural Gas (Bcf)	NGLs (MMBbls)	Total (MMBoe)	% Oil	% Liquids(1)	% Developed	Production (Boe/d)
Midland Basin	34.9	52.7	10.2	53.9	65	84	40	7,293

(1) Includes both oil and NGLs.

Competition and Markets

General

We are the operator of approximately 95% of our net acreage. The vast majority of our 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 and Ector. As operator, we design and manage the development of a well 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

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petroleum engineers, geologists and land professionals who work to improve production rates, increase reserves and lower the cost of operating our oil and natural gas properties

Marketing and Customers

We market the majority of the oil and natural gas production from properties we operate for both our account and the account of the other working interest owners in these properties. We sell our natural gas production to purchasers at market prices. We sell all of our natural gas under contracts with terms of 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).

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, 2013, four purchasers accounted for more than 10% of our revenue: Shell Trading (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 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 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 natural gas is 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. Our larger competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position.

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Seasonality of Business

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

Title to Properties

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

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

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

Oil and Natural Gas Leases

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

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.

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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.

Regulation of Production of Oil and Natural Gas

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

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. The 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

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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 Policy Act (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 (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 (EP Act of 2005) is a comprehensive compilation of tax incentives, authorized appropriations for grants and guaranteed loans, and significant changes to the statutory policy that affects all segments of the energy industry. Among other matters, the EP Act of 2005 amends the NGA to add an anti-market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provides FERC with additional civil penalty authority. The EP Act of 2005 provides FERC with the power to assess civil penalties of up to $1,000,000 per day for violations of the NGA and increases FERC s civil penalty authority under the NGPA from $5,000 per violation per day to $1,000,000 per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued Order No. 670, a rule implementing the anti-market manipulation provision of the EP Act of 2005, and subsequently denied rehearing. The rules make it unlawful to: (i) in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; (ii) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (iii) to engage in any act or practice that operates as a fraud or deceit upon any person. The new anti-market manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales or gathering, but does apply to activities of 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 million MMBtus of physical natural gas in the previous calendar year, including natural gas producers, gatherers and marketers, are now required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. 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.

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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 (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 federal 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

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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 generate materials in the course of our operations that may be regulated as hazardous substances but we are unaware of any liabilities for which we may be held responsible that would materially and adversely affect us.

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

Water Discharges

The federal Water Pollution Control Act (Clean Water Act) and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and natural gas wastes, into or near navigable waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers. 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. We are currently undertaking a review of recently acquired oil properties to determine the need for new or updated SPCC plans and, where necessary, we will be developing or upgrading such plans implementing the physical and operation controls imposed by these plans, the costs of which are not expected to be substantial.

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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, 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, on August 16, 2012, the EPA published 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 (NSPS) and NESHAP programs. With regards to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from three subcategories of fractured and refractured gas wells for which well completion operations are conducted: (i) wildcat (exploratory) and delineation gas wells; (ii) low reservoir pressure non-wildcat and non-delineation gas wells; and (iii) 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 after October 15, 2012. However, the other wells must use reduced emission completions, also known as green completions, with or without combustion devices, after January 1, 2015. These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, effective October 15, 2012, and from pneumatic controllers and storage vessels, effective October 15, 2013. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. The EPA intends to issue revised rules in 2013 that are likely responsive to some of these requests. For example, on April 12, 2013, the EPA published a proposed amendment extending compliance dates for certain storage vessels, and on August 5, 2013, the EPA issued a press release announcing that it had finalized the proposed amendment, and we anticipate that this rulemaking will be made effective by the EPA publication in the Federal Register in the very near future. 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 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, establish Prevention of Significant Deterioration (PSD) construction and Title V operating permit reviews for certain large stationary sources that are potential major sources of GHG emissions. On July 12, 2012, the EPA issued a final rule that retained previously established emissions thresholds such that only these large stationary sources are subject to greenhouse gas permitting, but those thresholds could be adjusted downward in the future. And despite numerous legal challenges to the EPA s authority to regulate GHGs, federal courts have affirmed that the EPA does have the authority to regulate greenhouse gas emissions under the Clean Air Act. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet best available control technology standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air

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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. In addition, the EPA has continued to adopt GHG regulations of other industries, such as the recently re-proposed September 2013 GHG rule restricting future development of coal-fired power plants. As a result of this continued regulatory focus, future GHG regulations of the oil and natural gas industry remain a possibility. 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.

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 that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products. In any event, the Obama administration recently announced its Climate Action Plan, which, among other things, directs federal agencies to develop a strategy for the reduction of methane emissions, including emissions from the oil and natural gas agency. As part of the Climate Action Plan, the Obama Administration also announced that it intends to adopt additional regulations to reduce emissions of GHGs and to encourage greater use of low carbon technologies in the coming years. 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.

Hydraulic Fracturing Activities

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The 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 typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the federal Safe Drinking Water Act (SDWA) over certain hydraulic fracturing activities involving the use of diesel fuels and published draft permitting guidance in May 2012 addressing the performance of such activities using diesel fuels. The EPA has yet to finalize its draft permitting guidance. In November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing and the agency currently plans to issue a Notice of Proposed Rulemaking that would seek public input on the design and scope of such disclosure regulations. To date, the EPA has not issued a Notice of Proposed Rulemaking; therefore, it is unclear how any federal disclosure requirements that add to any applicable state disclosure requirements already in effect may affect our operations.

In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. Specifically, the Fracturing Responsibilities and Awareness of Chemicals Act (the FRAC Act) has been introduced in each Congress since 2008 to accomplish these purposes, and on May 9, 2013, the FRAC Act was again re-introduced. If such legislation were to pass, it could result in substantial compliance costs and could negatively impact our ability to conduct hydraulic fracturing activities.

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 June 2011, Texas enacted a law requiring oil and natural gas operators to publicly disclose the chemicals used in the hydraulic fracturing process, effective as of September 1, 2011. The Texas Railroad Commission adopted rules and

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regulations applicable to all wells for which the Texas Railroad Commission issues an initial drilling permit on or after February 1, 2012. The new regulations require that well operators disclose the list of chemical ingredients subject to the requirements of the federal Occupational Safety and Health Act (OSHA) for disclosure on an internet website and also file the list of chemicals with the Texas Railroad Commission with the well completion report. The total volume of water used to hydraulically fracture a well must also be disclosed to the public and filed with the Texas Railroad Commission. Furthermore, on May 23, 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. The well integrity rule takes effect in January 2014. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular or prohibit the performance of well drilling in general or hydraulic fracturing in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements; experience delays or curtailment in the pursuit of exploration, development or production activities; and perhaps even be precluded from drilling wells.

Certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a first progress report outlining work currently underway by the agency released on December 21, 2012, and a final report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review by late 2014. 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 by 2014. In addition, the U.S. Department of the Interior published a revised proposed rule on May 24, 2013, that would implement updated requirements for hydraulic fracturing activities on federal lands, including new requirements relating to public disclosure, well bore integrity and handling of flowback water. The opportunity for the public to comment on the revised proposed rule lapsed on August 23, 2013; therefore, the Department of Interior finalization of the revised proposed rule is not expected for some time. 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 under the SDWA or other regulatory mechanisms.

ESA and Migratory Birds

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 may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for oil and natural gas development.

Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing of more than 250 species as endangered or threatened under the ESA by no later than completion of the agency s 2017 fiscal year. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The federal government

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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 2013.

OSHA

We are subject to the requirements of the 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 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, 2013, we had 36 full-time employees. We hire independent contractors on an as needed basis. We have no collective bargaining agreements with our employees. We believe that our employee relationships are satisfactory.

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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 Item 1. Business Competition and Markets and Regulation of the Oil and Gas Industry, and 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.

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 (NGP). As a result, there is only limited historical financial and operating information available upon which to base your evaluation of our performance.

Oil and natural gas prices are volatile. A substantial or extended decline in commodity prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The prices we receive for our oil, natural gas and NGLs production heavily influence our revenue, profitability, access to capital and future rate of growth. Oil, natural gas and NGLs are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the commodities market has been volatile. This market will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil, natural gas and NGLs;
- the price and quantity of foreign imports;
- political and economic conditions in or affecting other producing countries, including the Middle East, Africa, South America and Russia;
- the ability of members of the Organization of Petroleum Countries to agree to and maintain oil price and production controls;

- 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;

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- expectations about future commodity prices; and

- domestic, local and foreign governmental regulation and taxes.

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, natural gas and NGLs that we can produce economically.

If commodity prices decrease, 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 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. We currently estimate our 2014 capital budget for drilling, completion, recompletion and infrastructure will be approximately $365 million. Our capital budget excludes acquisitions. We expect to fund 2014 capital expenditures with cash generated by operations, borrowings under our revolving credit facility and possibly through asset sales or additional capital market transactions. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, oil 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. We intend to finance our near-term capital expenditures primarily through cash flow from operations and through borrowings under our revolving credit facility; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities or the sale of assets. The issuance of additional indebtedness would require that a portion of our cash flow from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flow from operations to fund working capital, capital expenditures and acquisitions.

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

- our proved reserves;

- the level of hydrocarbons we are able to produce from existing wells;

- the prices at which our production is sold;
- our ability to acquire, locate and produce new reserves; and
- our ability to borrow under our revolving credit facility.

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.

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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.

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.

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 greenhouse gases (GHGs) and limitations on hydraulic fracturing;

- pressure or irregularities in geological formations;

- shortages of or delays in obtaining equipment and qualified personnel or in obtaining water for hydraulic fracturing activities;

- equipment failures or accidents;

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

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- 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.

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, 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 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.

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

Our revolving credit facility contains a number of significant covenants (in addition to covenants restricting the incurrence of additional indebtedness), including restrictive covenants that may limit our ability to, among other things:

- incur additional indebtedness;
- make loans to others;
- make investments;
- merge or consolidate with another entity;

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- make certain payments;
- hedge future production or interest rates;
- incur liens;
- sell assets; 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. These restrictions may also limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under our revolving credit facilities impose on us.

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

Any significant reduction in our borrowing base under our 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 $300 million, with lender commitments of $500 million.

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.

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

We enter into derivative instrument contracts for a significant portion of our 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

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- there are issues with regard to legal enforceability of such instruments.

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

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

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 will 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, our recovery efficiencies may be worse than expected, and production declines may be greater than we estimate and may be rapid and irregular when compared to initial production rates. In addition, we may adjust reserve estimates to reflect production history, results of exploration and development, existing commodity prices and other factors.

You should not assume that the present value of future net revenues from our reserves is the current market value of our estimated reserves. We generally base the estimated discounted future net cash flows from reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

Our Effective Horizontal Acreage is based on our and other operators   current drilling results and our interpretation of available geologic and engineering data and therefore is an inexact estimate subject to various uncertainties.

Our Effective Horizontal Acreage is equal to what we believe to be our combined horizontal acreage position that is prospective for hydrocarbon production across our target horizontal zones underneath our total surface acreage of 42,428 gross (33,933 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.

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

Our management team has specifically identified and scheduled certain drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. These drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the numerous drilling locations we have identified will ever be drilled or if we will be able to produce natural gas or oil from these or any other drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the drilling locations are obtained, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified.

As of December 31, 2013, we had identified 1,157 horizontal drilling locations in multiple horizons across our acreage based on spacing of five wells per 640 acres for short laterals and five wells per 960 acres for long laterals. Additionally, based on our evaluation of applicable geologic and engineering data as of December 31, 2013, we had 297 identified vertical drilling locations on 40-acre spacing and an additional 500 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. 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, natural gas and NGLs. Any decreases in production due to poor weather conditions will have an adverse effect on our revenues, which will in turn negatively affect our cash flow from operations.

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

Water is an essential component of deep shale oil and natural gas production during both the drilling and hydraulic fracturing processes. According to the Lower Colorado River Authority, during 2011, Texas experienced the lowest inflows of water of any year in recorded history, and as of August 2013, all of New Mexico is officially in a drought. These drought conditions have led governmental authorities to restrict the use of water subject to their jurisdiction for hydraulic fracturing to protect local water supplies. If we are unable to obtain water to use in our operations, we may be unable to economically produce oil and natural gas, which could have a material and adverse effect on our financial condition, results of operations and cash flows.

Our producing properties are located in the 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, and 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

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capacity constraints, market limitations, availability of equipment and personnel, water shortages or other drought related conditions or interruption of the processing or transportation of oil, natural gas or NGLs.

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, 2013, 60% 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 generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploitation, development and exploration activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future reserves and production, and therefore our future cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves 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, 2013, four purchasers accounted for more than 10% of our revenue: Shell Trading (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%). For the year ended December 31, 2011, one purchaser accounted for more than 10% of our revenue: Plains Marketing, L.P. (78%). The loss of any of these purchasers could materially and adversely affect our revenues in the short-term.

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

We may incur significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to our exploration, development and production activities. These delays, costs and liabilities could arise under a wide range of federal, regional, state and local laws and regulations relating to protection of the environment and worker health and safety, including regulations and enforcement policies that have tended to become increasingly strict over time resulting in longer waiting periods to receive permits and other regulatory approvals. These laws include, but are not limited to, the federal Clean Air Act (and comparable state laws and regulations that impose obligations related to air emissions), the Clean Water Act and OPA (and comparable state laws and regulations that impose requirements related to discharges of pollutants into regulated bodies of water), RCRA (and comparable state laws that impose requirements for the handling and disposal of waste from our facilities), CERCLA and the community right to know regulations under Title III of the act (and comparable state laws that regulate the cleanup of hazardous substances that may have been released at properties currently or previously owned or operated by us or at locations we sent waste for disposal and that comparable state laws that require organization and/or disclosure of information about hazardous materials we use or produce), the federal Occupational Safety and Health Act (which establishes workplace standards for the protection of health and safety of employees and requires a hazardous communications program) and the ESA and the Migratory Bird Treaty Act (and comparable state laws that seek to ensure activities do not jeopardize endangered or threatened animals, fish, plant species; do not destroy or modify the critical habitat of such species; and do not result in the taking, killing or possessing migratory birds). Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations.

Strict, joint and several liabilities may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental and worker health and safety impacts of our operations. We have been named from time to time as a defendant in litigation related to such matters. Also, new laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we were not able to recover the resulting costs through insurance or increased revenues, our business, financial condition or results of operations could be materially and adversely affected.

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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 will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects. Further, our drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, including:

- unexpected drilling conditions;

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- 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 businesses that complement or expand our current business. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms. Competition for acquisitions may also increase the cost of, or cause us to refrain from, completing acquisitions.

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

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

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities.

Our oil and natural gas exploration, production and transportation operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. Failure to comply with these laws and regulations may also result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties, including the assessment of natural resource damages, as well injunctions limiting or prohibiting our activities. These regulations could change to our detriment. Our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Such costs could have a material adverse effect on our business, financial condition and results of operations.

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.

Our business is subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and the production and transportation of, oil and natural gas. Failure to comply with such laws and regulations, including any evolving interpretation and enforcement by governmental authorities, could have a material adverse effect on our business, financial condition and results of operations.

Changes to existing or new regulations may unfavorably impact us, could result in increased operating costs and could have a material adverse effect on our financial condition and results of operations. Such potential regulations could increase our operating costs, reduce our liquidity, delay or halt our operations or otherwise alter the way we conduct our business, which could in turn have a material adverse effect on our financial condition, results of operations and cash flows. Further, the discharges of oil, natural gas, NGLs and other pollutants into the air, soil or water may give rise to significant liabilities on our part to the government and third parties. See Item 1. Business Regulation of Environmental and Occupational Safety and Health Matters for a further description of laws and regulations that affect us.

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 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, FERC has civil penalty authority under the NGA and the NGPA to impose penalties for current violations of up to $1 million/d 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 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, establish PSD, construction and Title V operating permit reviews for certain large stationary sources that are potential major sources of GHG emissions. On July 12, 2012, the EPA issued a final rule that retained previously established emissions thresholds such that only these large stationary sources are subject to greenhouse gas permitting, but those thresholds could be adjusted downward in the future. And despite numerous legal challenges to the EPA s authority to regulate GHGs, federal courts have affirmed that the EPA does have the authority to regulate greenhouse gas emissions under the Clean Air Act. Facilities required to obtain PSD permits

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for their GHG emissions also will be required to meet best available control technology standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and natural gas production sources in the United States on an annual basis, which include certain of our operations. In addition, the EPA has continued to adopt GHG regulations of other industries, such as the recently re-proposed September 2013 GHG rule restricting future development of coal-fired power plants. As a result of this continued regulatory focus, future GHG regulations of the oil and natural gas industry remain a possibility. 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.

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 that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products. In any event, the Obama administration recently announced its Climate Action Plan, which, among other things, directs federal agencies to develop a strategy for the reduction of methane emissions, including emissions from the oil and natural gas agency. As part of the Climate Action Plan, the Obama Administration also announced that it intends to adopt additional regulations to reduce emissions of GHGs and to encourage greater use of low carbon technologies in the coming years. 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 natural gas and/or oil 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 typically is 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 draft permitting guidance in May 2012 addressing the performance of such activities using diesel fuels. The EPA has yet to finalize its draft permitting guidance. In November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing and the agency currently plans to issue a Notice of Proposed Rulemaking that would seek public input on the design and scope of such disclosure regulations. To date, the EPA has not issued a Notice of Proposed Rulemaking; therefore, it is unclear how any federal disclosure requirements that add to any applicable state disclosure requirements already in effect may affect our operations. In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process.

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 June 2011, Texas enacted a law requiring oil and natural gas operators to publicly disclose the chemicals used in the

hydraulic fracturing process, effective as of September 1, 2011. The Texas Railroad Commission adopted rules and regulations applicable to all wells for which the Texas Railroad Commission issues an initial drilling permit on or after February 1, 2012. The new regulations require that well operators disclose the list of chemical ingredients subject to the requirements of OSHA for disclosure on an internet website and also file the list of chemicals with the Texas Railroad Commission with the well completion report. The total volume of water used to hydraulically fracture a well must also be disclosed to the public and filed with the Texas Railroad Commission. Furthermore, on May 23, 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. The well integrity rule takes effect in January 2014. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular or prohibit the performance of well drilling in general or hydraulic fracturing in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development or production activities, and perhaps even be precluded from drilling wells.

Certain governmental reviews have been conducted or are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a first progress report outlining work currently underway by the agency released on December 21, 2012, and a final report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review by late 2014. 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 by 2014. In addition, the U.S. Department of the Interior published a revised proposed rule on May 24, 2013, that would implement updated requirements for hydraulic fracturing activities on federal lands, including new requirements relating to public disclosure, well bore integrity and handling of flowback water. The opportunity for the public to comment on the revised proposed rule lapsed on August 23, 2013; therefore, the Department of Interior finalization of the revised proposed rule is not expected for some time. 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 under the SDWA or other regulatory mechanisms, and could ultimately make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

Further, on April 17, 2012, the EPA released final rules that subject all oil and natural gas operations (production, processing, transmission, storage and distribution) to regulation under the NSPS and the National Emission Standards for Hazardous Air Pollutants (NESHAPS) programs. These rules became effective on October 15, 2012. The 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 will be 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. In October 2012, several challenges to the EPA s rules were filed. In a January 16, 2013 unopposed motion to hold this litigation in abeyance, the EPA indicated that it may reconsider some aspects of the rules. Depending on the outcome of such proceedings, the rules may be modified or rescinded or the EPA may issue new rules. Additionally, on December 11, 2012, seven states submitted a notice of intent to sue the EPA to compel the agency to make a determination as to whether standards or performance limiting methane emissions from oil and natural gas sources is appropriate and if so, to promulgate performance standards for methane emissions from existing oil and natural gas sources.

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Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil or natural gas and secure 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 future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

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

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

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

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

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

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

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. For example, as of December 31, 2013, outstanding borrowings subject to variable interest rates were approximately $56.2 million, and a 1.0% increase in interest rates would result in an increase in annual interest expense of approximately $0.6 million, assuming the $56.2 million in debt was outstanding for the full year, before the effects of increased interest rates on the value of our interest rate swap contracts and income taxes. 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.

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

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

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

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

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 2014 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 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

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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 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 SEC to promulgate rules and regulations implementing the Dodd-Frank Act. In its rulemaking under the Dodd-Frank Act, the CFTC has issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide derivative transactions would be exempt from these position limits. The position limits rule was vacated by the United States District Court for the District of Columbia in September of 2012 although the CFTC has stated that it will appeal the District Court s decision. The CFTC also has finalized other regulations, including critical rulemakings on the definition of swap, security-based swap, swap dealer and major swap participant. The Dodd-Frank Act and CFTC rules also will require us in connection with certain derivatives activities to comply with clearing and trade-execution requirements (or take steps to qualify for an exemption to such requirements). In addition, new regulations may require us to comply with margin requirements although these regulations are not finalized and their application to us is uncertain at this time. Other regulations also remain to be finalized, and the CFTC recently has delayed the compliance dates for various regulations already finalized. As a result, it is not possible at this time to predict with certainty the full effects of the Dodd-Frank Act and CFTC rules on us and the timing of such effects. The Dodd-Frank Act also may require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts (including through requirements to post collateral, which could adversely affect our available liquidity), materially alter the terms of derivative contracts and reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and CFTC rules, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act 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. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and CFTC rules is to lower commodity prices. Any of these consequences could have a material and adverse effect on us, our financial condition or our results of operations.

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

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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.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Our properties include working interests in approximately 42,428 surface acres located in the Permian Basin in the Texas counties of Midland, Martin, Andrews, Ector, Dawson and Upton. The following table summarizes our surface acreage by county as of December 31, 2013.

	Gross	Net
County:		
Andrews	3,304	3,304
Ector	4,898	4,782
Martin	6,579	5,767
Midland	17,546	11,414
Dawson	9,464	8,092
Upton	637	574
Total	42,428	33,933

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. Operators in the Permian Basin have produced more than 29 billion barrels of oil and 75 trillion cubic feet of natural gas over the past 90 years, and the Permian Basin is estimated to contain recoverable oil and natural gas reserves exceeding that which has already been produced. With oil production of over 960 MBbls/d from over 80,000 wells during 2013, production from the Permian Basin represented 50% of the crude oil produced in Texas and approximately 17% of the crude oil produced onshore in the continental United States during such period. 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 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 and Ector. 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 position allows 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 position 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 140,435 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.

	Effective Horizontal Acreage(1)	
	Gross	**Net**
Target Horizontal Zones:		
Middle Spraberry	41,791	33,359
Lower Spraberry	42,428	33,933
Wolfcamp A	26,493	19,892
Wolfcamp B	35,957	27,984
Wolfcamp D (Cline)	32,327	25,267
Total	178,996	140,435

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(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.

The Midland 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 has shown a trend towards horizontal development. As of January 2012, there were 20 horizontal rigs and approximately 260 vertical rigs operating in the Midland Basin. As of March 2014, there were 109 horizontal rigs and approximately 166 vertical rigs operating within the same area. 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.

Ryder Scott, our independent petroleum engineering firm, has estimated that as of December 31, 2013, proved reserves net to our interest in our properties were approximately 53,883 MBoe, of which 40% 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, 2013, our average net daily production was 7,293 Boe/d (approximately 70% oil, 14% natural gas and 16% NGLs), of which 15% was from horizontal well production and 85% was from vertical well production. During 2012, our average net daily production was 5,089 Boe/d (approximately 69% oil, 14% natural gas and 17% NGLs), of which 1% was from horizontal well production and 99% was from vertical well production. As of December 31, 2013, we produced from 24 horizontal and 338 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 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. We have laid approximately 85 miles of oil, natural gas and water transport lines to support gathering and transportation activities on our properties. To secure adequate water supplies, we have drilled eight 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 three saltwater disposal wells on our properties and we have an additional saltwater disposal well in the completion process. We sold one water source well and one saltwater disposal well that we operated to Resolute as part of an asset disposition that occurred in part in December 2012 and in part in March 2013.

Recent and Future Activity. A total of 109 gross (69 net) wells were drilled on our acreage during 2012, and during 2013, 102 gross (53 net) wells were drilled on our acreage. We recently drilled our first multi-well pad (two

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well) layout and anticipate utilizing a three-well pad layout in 2014. We expect these multi-well pads to increase our capital efficiency and intend to begin implementing multi-well pad drilling on a regular basis.

As of December 31, 2013, we had identified 1,157 horizontal drilling locations in multiple horizons across our acreage based on spacing of five wells per 640 acres for short laterals and five wells per 960 acres for long laterals. In addition, based on our evaluation of applicable geologic and engineering data, as of December 31, 2013 we had 297 identified vertical drilling locations on 40-acre spacing and an additional 500 identified vertical drilling locations based on 20-acre downspacing. In this Report, 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.

Oil and Natural Gas Data

Proved Reserves

Evaluation and Review of Proved Reserves. Our pro forma proved reserve estimates as of December 31, 2013 were prepared by Ryder Scott, our independent petroleum engineers. The technical persons responsible for preparing our proved reserve estimates meet the requirements with regard to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Ryder Scott does not own an interest in any of our properties, nor is it employed by us on a contingent basis. A copy of the independent petroleum engineering firm s proved reserve report as of December 31, 2013 is included as an exhibit to this Report. Our pro forma reserve report as of December 31, 2012 is an internally prepared reserve 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 Ryder Scott 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 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 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

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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, 2013 and 2012 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, we, in the case of our internally prepared reserve report as of December 31, 2012, and Ryder Scott, in the case of the reserve report as of December 31, 2013, considered many factors and assumptions, including the use of reservoir parameters derived from geological, geophysical and engineering data which cannot be measured directly, economic criteria based on current costs and the SEC pricing requirements and forecasts of future production rates.

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 Pro Forma Oil and Natural Gas Reserves. The following table presents our estimated 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 and December 31, 2012, based on the proved reserve reports as of December 31, 2013 by Ryder Scott, our independent petroleum engineering firm, and based on our internally generated reserve reports as of December 31, 2012, 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 proved reserve report as December 31, 2013 prepared by Ryder Scott with respect to our properties is included as an exhibit to this Report.

	At December 31, 2013	At December 31, 2012
Proved developed reserves:		
Oil (MBbls)	13,921	8,712
Natural gas (MMcf)	21,008	16,037
NGLs (MBbls)	3,965	3,074
Total (MBoe)	21,387	14,459
Proved undeveloped reserves:		
Oil (MBbls)	21,011	18,726
Natural gas (MMcf)	31,665	29,044
NGLs (MBbls)	6,207	5,457
Total (MBoe)	32,496	29,024

Total proved reserves:		
Oil (MBbls)	34,932	27,438
Natural gas (MMcf)	52,673	45,081
NGLs (MBbls)	10,172	8,531
Total (MBoe)	53,883	43,483

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The changes from December 31, 2012 estimated proved reserves to December 31, 2013 estimated proved reserves reflect production during this period of approximately 2,662 MBoe, net negative revisions of approximately 225 MBoe and additions of approximately 13,287 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, 2013, which is included as an exhibit to this Report.

Pro Forma PUDs

Year Ended December 31, 2013

As of December 31, 2013, our PUDs totaled 21,011 MBbls of oil, 31,665 MMcf of natural gas and 6,207 MBbls of NGLs, 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 and $97.7 million to convert non-proved reserves 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.

Year Ended December 31, 2012

As of December 31, 2012, our PUDs totaled 18,726 MBbls of oil, 29,044 MMcf of natural gas and 5,457 MBbls of NGLs, for a total of 29,024 MBoe. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

Changes in PUDs that occurred during 2012 were primarily due to:

- additions of approximately 14,741 MBoe attributable to extensions resulting from strategic drilling of wells by us to delineate our acreage position;

- the conversion of approximately 4,965 MBoe attributable to PUDs into proved developed reserves; and

- negative revisions of approximately 37,361 MBoe in PUDs were due to a combination of adjustments in working interest, performance revisions and a reduction in PUD reserves that resulted from our strategic

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decision to not include 20-acre PUD locations in our reserves in favor of focusing our capital expenditures on horizontal locations and, to a lesser extent, on 40-acre vertical locations.

During the twelve months ended December 31, 2012, we spent $93.1 million to convert PUDs to proved developed reserves and $79.1 million to convert non-proved reserves 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, 2012, 1% of our total proved reserves were classified as proved developed non-producing.

Oil and Natural Gas Production Prices and Costs

Production and Price History

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:

	Predecessor For the Year Ended December 31,			Pro Forma(1) Year Ended December 31,	
	2013	**2012**	**2011**	**2013**	**2012**
Production data:					
Oil (MBbls)	1,167	1,040	618	1,867	1,278
Natural gas (MMcf)	1,597	1,576	971	2,287	1,629
NGLs (MBbls)	250	264	(2)	414	313
Total (MBoe)	1,683	1,567	780	2,662	1,862
Average prices before effects of hedges(3)(4):					
Oil (per Bbl)	$ 94.55	$ 87.92	$ 91.84	$ 95.01	$ 88.16
Natural gas (per Mcf)	3.37	2.72	7.44	3.34	2.65
NGLs (per Bbl)(2)	29.26	32.94		28.16	33.72
Total (per Boe)	$ 73.11	$ 66.65	$ 82.05	$ 73.89	$ 68.46
Average realized prices after effects of hedges(3)(4):					
Oil (per Bbl)	$ 94.95	$ 88.25	$ 91.66	$ 95.24	$ 88.42
Natural gas (per Mcf)	3.37	2.72	7.44	3.34	2.65
NGLs (per Bbl)(2)	29.26	32.94		28.16	33.72
Total (per Boe)	$ 73.37	$ 66.86	$ 81.90	$ 74.06	$ 68.64
Average costs (per Boe):					
Lease operating expenses	$ 8.71	$ 8.20	$ 7.32	$ 8.72	$ 8.44
Production and ad valorem taxes	4.95	4.83	5.37	4.97	5.04

Depreciation, depletion and amortization	28.02	31.15	21.30	30.24	35.29
General and administrative expenses(5)	2.29	1.82	4.50	1.40	1.44

(1) Does not include the results related to the Verde Acquisition or Pecos Contribution due to their lack of significance to our combined financial results.

(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) Average prices shown in the table reflect prices both before and after the effects of our realized 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.

(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) Pro forma general and administrative expenses do not include additional expenses we would have incurred as a result of being a public company.

Pro Forma Productive Wells

As of December 31, 2013, on a pro forma basis, we owned an average 66% working interest in 362 gross productive wells. 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

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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.

Pro Forma Developed and Undeveloped Acreage

The following table sets forth information as of December 31, 2013 relating to our leasehold acreage:

	Developed acreage(1)		**Undeveloped acreage(2)**		**Total acreage**	
	Gross(3)	**Net(4)**	**Gross(3)**	**Net(4)**	**Gross(3)**	**Net(4)**
Midland Basin	13,520	9,139	28,908	25,156	42,428	33,933

(1) Developed acres are acres spaced or assigned to productive wells and does not include undrilled acreage held by production under the terms of the lease.

(2) Undeveloped acres are acres on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil or natural gas, regardless of whether such acreage contains proved reserves.

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

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

Many of the leases comprising the undeveloped acreage set forth in the table above will expire at the end of their respective primary terms unless production from the leasehold acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production. The following table sets forth the gross and net undeveloped acreage, as of December 31, 2013, 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.

	2014		**2015**		**2016**		**2017**		**2018**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Midland Basin	2,419	2,102	4,595	4,029	19	1	4,358	3,597	0	0

Pro Forma 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.

	For the Year Ended December 31,					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Exploratory Wells:						
Productive(1)			1.0	0.4		
Dry						
Total Exploratory			1.0	0.4		
Development Wells:						
Productive(1)	102.0	52.9	108.0	68.8	81.0	62.5
Dry						
Total Development	102.0	52.9	108.0	68.8	81.0	62.5
Total Wells:						
Productive(1)	102.0	52.9	109.0	69.2	81.0	62.5
Dry						
Total	102.0	52.9	109.0	69.2	81.0	62.5

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

ITEM 3. LEGAL PROCEEDINGS

We are party to lawsuits arising in the ordinary course of our business. We cannot predict the outcome of any such lawsuits with certainty, but management believes it is remote that pending or threatened legal matters will have a material adverse impact on our financial condition. See Note 10 of Notes to Combined Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information regarding legal proceedings involving the Company.

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.

On March 24, 2014, the last sale price of our common stock, as reported on the NYSE, was $29.49 per share. On March 24, 2014, the Company s common stock was held by eight holders of record.

Dividends

We have not paid any cash dividends since our inception. Covenants contained in our revolving credit facility restrict the payment of cash dividends on our common stock. 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.

ITEM 6. SELECTED FINANCIAL DATA

The following tables set forth the selected historical combined financial data of our accounting predecessor and selected pro forma combined financial data of RSP Permian, Inc., for the years indicated. Our accounting predecessor reflects the combined results of RSP Permian, L.L.C. and Rising Star. For more information regarding our predecessor, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Our Predecessor and RSP Permian, Inc.

The selected historical combined 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 unaudited pro forma combined financial data of RSP Permian, Inc. for the year ended December 31, 2013 and 2012 were derived from the unaudited pro forma combined financial data. The pro forma combined financial data assumes that our IPO and the IPO Transactions had taken place on January 1, 2012, in the case of the pro forma combined statement of operations data for the year ended December 31, 2013 and 2012.

Our historical results are not necessarily indicative of future operating results. The selected combined financial data presented below are qualified in their entirety by reference to, and should be read in conjunction with, Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations and the historical combined financial statements of our predecessor and the unaudited pro forma combined financial statements of RSP Permian, Inc. included in this Report.

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	Predecessor Year Ended December 31, 2013	Predecessor Year Ended December 31, 2012	Predecessor Year Ended December 31, 2011	RSP Permian, Inc. Pro Forma Year Ended December 31, 2013 (Unaudited)	RSP Permian, Inc. Pro Forma Year Ended December 31, 2012 (Unaudited)
	(In thousands, except per share data)				
Statement of Operations Data:					
Revenues:					
Oil sales	$ 110,345	$ 91,441	$ 56,772	$ 177,415	$ 112,631
Natural gas sales	5,383	4,284	7,217	7,647	4,313
NGL sales(1)	7,314	8,702		11,644	10,565
Total revenues	$ 123,042	$ 104,427	$ 63,989	$ 196,706	$ 127,509
Operating expenses:					
Lease operating expenses	$ 14,664	$ 12,854	$ 5,712	$ 23,218	$ 15,710
Production and ad valorem taxes	8,326	7,575	4,192	13,236	9,389
Depreciation, depletion and amortization	47,158	48,803	16,612	80,487	65,701
Asset retirement obligation accretion	121	115	46	199	162
Impairments			2,241		
General and administrative expenses	3,852	2,859	3,509	3,716	2,677
Total operating expenses	74,121	72,206	32,312	120,856	93,639
(Gain) on sale of assets	(22,700)	(6,734)	(105,333)		
Operating income	$ 71,621	$ 38,955	$ 137,010	$ 75,850	$ 33,870
Other income (expense):					
Other income	$ 1,202	$ 884	$ 163	$ 1,202	$ 849
Loss on derivative instruments	(2,607)	(796)	(1,979)	(2,607)	(796)
Interest expense	(5,216)	(3,474)	(3,472)	(10,890)	(8,929)
Total other income (expense)	$ (6,621)	$ (3,386)	$ (5,288)	$ (12,295)	$ (8,876)
Income before taxes	65,000	35,569	131,722	63,555	24,994
Income tax (expense) benefit	(2,262)	339	(550)	(22,717)	(8,554)
Net Income	$ 62,738	$ 35,908	$ 131,172	$ 40,838	$ 16,440
Per share data (unaudited):					
Net earnings per common share:					
Basic and diluted				$ 0.56	$ 0.23
Weighted average common shares outstanding:					
Basic and diluted				72,500	72,500
Pro Forma C Corporation Data (unaudited)(2):					
Net income before taxes	$ 62,738				
Pro forma for income taxes	(22,586)				
Pro forma net income	$ 40,152				
Cash Flow Data:					
Net cash provided by operating activities	$ 73,345	$ 72,803	$ 26,243		
Net cash provided by (used in) investing activities	(119,591)	(113,220)	83,846		
Net cash provided by financing activities	8,248	81,583	(105,155)		
Other Financial Data:					
Adjusted EBITDAX(3)	$ 92,022	$ 78,745	$ 48,698	$ 152,358	$ 97,304

(1) 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.

(2) 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 2012 and 2013 as if RSP Permian, L.L.C. and Rising Star were subject to income taxes since January 1, 2012. For 2013 and 2012 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

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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.

(3) Adjusted EBITDAX is a non-GAAP financial measure. For a definition of Adjusted EBITDAX and a reconciliation of Adjusted EBITDAX to net income, see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations How We Evaluate Our Operations Adjusted EBITDAX.

	Predecessor Year Ended December 31, 2013	2012
	(In thousands)	
Balance Sheet Data:		
Cash and cash equivalents	$ 13,234	$ 51,232
Other current assets	33,901	31,124
Total current assets	47,135	82,356
Property, plant and equipment, net	516,288	421,412
Other long-term assets	24,232	9,470
Total assets	$ 587,655	$ 513,238
Current liabilities	30,866	28,165
Long-term debt	128,155	111,586
NPI payable	36,931	16,583
Other long-term liabilities	4,822	3,061
Total members equity	386,881	353,843
Total liabilities and members equity	$ 587,655	$ 513,238

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

You should read the following discussion of our historical performance and financial condition together with Item 6. Selected Financial Data, the description of the business appearing in Item 1. Business, and the financial statements and the related notes in Part II, Item 8 of this Annual Report on Form 10-K. This discussion contains forward-looking statements that are based on the views and beliefs of our management, as well as assumptions and estimates made by our management. Actual results could differ materially from such forward-looking statements as a result of various risk factors, including those that may not be in the control of management. Factors that could cause or contribute to these differences include those discussed below and elsewhere in this report, particularly in Item 1A. Risk Factors .

Our Predecessor and RSP Permian, Inc.

RSP Permian, Inc. was formed in September 2013 and does not have historical financial operating results. For purposes of this Annual Report, our accounting predecessor reflects the combined results of RSP Permian, L.L.C. and Rising Star. RSP Permian, L.L.C. was formed in 2010 to engage in the acquisition, development, exploration and exploitation of oil and natural gas reserves in the Permian Basin. In connection with our IPO, pursuant to the terms of a corporate reorganization, all of the interests in RSP Permian, L.L.C. were exchanged for shares of common stock of RSP Permian, Inc. and the right to receive approximately $27.7 million in cash. Also in connection with our IPO, Rising Star contributed to RSP Permian, Inc. working interests in certain acreage and wells in which RSP Permian, L.L.C. already has working interests in exchange for shares of RSP Permian, Inc. s common stock and the right to receive approximately $1.7 million in cash. These contributed assets represent substantially all of Rising Star s production and revenues for each of the years ended December 31, 2013 and December 31, 2012.

Overview

Our Predecessor s financial and operating performance for 2013 included the following highlights:

- Completed the $214 million sale of assets to Resolute (Resolute Disposition), generating an attractive gain and return on capital;
- Successfully transitioned our drilling program to primarily a horizontal program from a vertical program;
- Increased production by 8%, net income by 75% and Adjusted EBITDAX by 17%, in each case, as compared to 2012, despite selling approximately 40% of the then current production to Resolute;
- Acquired additional working interests in the Spanish Trail Assets (defined below), properties contiguous to our existing acreage and prospective for horizontal drilling, for approximately $121 million;
- Successfully drilled and completed the first Lower Spraberry and Middle Spraberry horizontal wells in the Midland Basin;
- Increased our commercial bank syndicate from five banks to 11 banks, expanding our borrowing base from $95 million to $140 million; and

- Secured a $70 million term loan to partially finance the Spanish Trail Acquisition (defined below).

In addition, in January 2014, we successfully completed our IPO, selling 23 million shares at $19.50 per share and raising $448.5 million in gross proceeds. The sale of primary shares resulted in net proceeds to the Company of approximately $166.0 million; we did not receive any proceeds from the sale of shares by selling stockholders.

During the year ended December 31, 2013, our average daily production was approximately 4,611 Boe/d, consisting of 3,197 Bbls/d of oil, 4,375 Mcf/d of natural gas and 685 Bbls/d of natural gas liquids, an increase of 8%, or 330 Boe/d, from average daily production of 4,281 Boe/d for the year ended December 31, 2012, consisting of 2,842 Bbls/d of oil, 4,305 Mcf/d of natural gas and 722 Bbls/d of natural gas liquids. As described below, we disposed of approximately 40% of our then-current production in connection with the Resolute Disposition, which closed in part in December 2012 and March 2013.

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During the year ended December 31, 2013, we drilled 42 gross (24 net) wells, and participated in an additional 60 gross (7 net) non-operated wells in the Permian Basin.

Recent Events

Resolute Disposition

Pursuant to a transaction that closed in part in December 2012 and in part in March 2013, we sold all of our working interests in approximately 2,600 net acres and 80 producing wells in the Permian Basin to Resolute for approximately $214 million.

Spanish Trail Acquisition

On September 10, 2013, we completed the acquisition of additional working interests in certain of our existing properties in the Permian Basin from Summit Petroleum, LLC and EGL Resources, Inc. (the Spanish Trail Acquisition). Together with the working interests acquired pursuant to the preferential purchase rights and contributed to us in connection with our IPO, as described below under Corporate Formation Transactions, the Spanish Trail Acquisition increased our working interests in approximately 5,400 gross acres and 70 gross producing wells (the Spanish Trail Assets). For the quarter ended September 30, 2013, average net daily production associated with the Spanish Trail Assets was approximately 1,329 Boe/d (approximately 72% oil, 12% natural gas and 16% NGLs).

The aggregate purchase price for the Spanish Trail Assets agreed to by us 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 a newly-formed entity, Collins & Wallace Holdings, LLC, which contributed these acquired assets for shares of RSP Permian, Inc. s common stock, as described in Corporate Formation Transactions The Collins and Wallace Contributions. The exercise of the preferential purchase rights reduced our effective purchase price from $155 million to $121 million. The Spanish Trail Acquisition was funded with a $70 million term loan, borrowings under our revolving credit facility and the issuance of an NPI as further described below.

Simultaneously with the closing of the Spanish Trail Acquisition, we 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 our $121 million purchase price, pursuant to ACTOIL s exercise of a right of first refusal granted by us in the agreement that governs the NPI investment. ACTOIL contributed this NPI, along with the other NPI in our assets, for shares of RSP Permian, Inc. s common stock, as described in Corporate Formation Transactions The ACTOIL NPI Repurchase.

Verde Acquisition

On October 10, 2013, we acquired leasehold interests in 9,464 gross (8,092 net) acres in the Midland Basin located just to the north of the Dawson and Martin county line toward the eastern half of Dawson County (the Verde Acquisition). We are the operator on 100% of this acreage.

This acreage currently contains no producing wells. However, we have identified approximately 234 gross horizontal drilling locations on this acreage, of which 78 are located in the Wolfcamp B zone, 78 are located in the Middle Spraberry zone and 78 are located in the Lower Spraberry zone. We expect the lateral lengths of the horizontal wells we drill in this area to range from approximately 4,500 feet to 7,500 feet.

Corporate Formation Transactions

Corporate Reorganization. Pursuant to the terms of a corporate reorganization that was completed in connection with our IPO, (i) the members of RSP Permian, L.L.C. contributed all of their interests in RSP Permian,

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L.L.C. to RSP Permian Holdco, L.L.C., a newly-formed entity that was wholly owned by such members, and (ii) RSP Permian Holdco, L.L.C. contributed all of its interests in RSP Permian, L.L.C. to RSP Permian, Inc. in exchange for shares of common stock of RSP Permian, Inc., an assignment of RSP Permian, L.L.C. s pro rata share of an escrow related to the Resolute Disposition (which escrow is described in Note 3 of the historical combined financial statements of RSP Permian, L.L.C. and Rising Star) and the right to receive approximately $27.7 million in cash. As a result of the reorganization, RSP Permian, L.L.C. became a wholly owned subsidiary of RSP Permian, Inc.

The Rising Star Acquisition. In connection with our IPO, we completed the Rising Star Acquisition. In exchange, Rising Star received 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 Collins and Wallace Contributions. Collins, Wallace LP and Collins & Wallace Holdings, LLC contributed to us certain working interests in certain of RSP Permian, L.L.C. s existing properties in the Permian Basin. In exchange, (i) Collins received shares of RSP Permian, Inc. s common stock and the right to receive approximately $1.6 million in cash, (ii) Wallace LP received shares of RSP Permian, Inc. s common stock and the right to receive $0.6 million in cash, and (iii) Collins & Wallace Holdings, LLC received shares of RSP Permian, Inc. s common stock. The Collins and Wallace Contributions occurred in connection with our 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 Permian, L.L.C. 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 Permian, L.L.C. owned prior to the Spanish Trail Acquisition; and (iii) Collins & Wallace Holdings, LLC s non-operated working interest in the Spanish Trail Assets.

The Pecos Contribution. Pecos, an entity owned by certain members of our management team, agreed to contribute to us certain working interests in certain acreage and wells in the Permian Basin in which RSP Permian, L.L.C. already has working interests (the Pecos Contribution). In exchange, Pecos received shares of RSP Permian, Inc. s common stock. The Pecos Contribution increased our working interests in approximately 650 gross acres and six producing wells. For the year ended December 31, 2013, the average net daily production associated with the Pecos Assets was 8 Boe/d (approximately 78% oil and 22% natural gas).

The ACTOIL NPI Repurchase. In July 2011, we sold to ACTOIL a 25% NPI in substantially all of our oil and natural gas properties taken as a whole. In addition, as discussed above under Recent Events Spanish Trail Acquisition, we sold to ACTOIL a 25% NPI in the oil and natural gas properties acquired by RSP Permian, L.L.C. in the Spanish Trail Acquisition. ACTOIL has agreed to the ACTOIL NPI Repurchase in exchange for shares of RSP Permian, Inc. s common stock. This contribution occurred in connection with our IPO.

The oil and natural gas properties that underpin ACTOIL s NPIs were owned and controlled by us prior to the repurchase. The NPIs entitled ACTOIL to 25% of the relevant properties cumulative revenues in excess of their cumulative direct operating expenses and capital expenditures. Because the cumulative revenues did not yet exceed the cumulative direct operating expenses and capital expenditures, we included the resultant net cash flow and the reserves associated with ACTOIL s NPIs in our historical proved reserve estimates.

How We Evaluate Our Operations

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

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

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See Sources of Our Revenues, Principal Components of Our Cost Structure and Adjusted EBITDAX for a discussion of these metrics.

Sources of Our Revenues

Our revenues are derived from the sale of our oil and natural gas production, as well as the sale of NGLs that are extracted from our natural gas during processing. Our oil and natural gas revenues do not include the effects of derivatives. For the years ended December 31, 2013, 2012 and 2011, our revenues were derived 90%, 88% and 89%, respectively, from oil sales and 4%, 4% and 11%, respectively, from natural gas sales. Our revenues from NGL sales for the years ended December 31, 2013 and 2012 were 6% and 8%, respectively. 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.

Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in commodity prices.

Production Volumes

The following table presents historical production volumes for our predecessor s properties for the years ended December 31, 2013, 2012 and 2011.

	Our Predecessor For the Year Ended December 31,		
	2013	**2012**	**2011**
Oil (MBbls)	1,167	1,040	618
Natural gas (MMcf)	1,597	1,576	971
NGLs (MBbls)	250	264	(1)
Total (MBoe)	1,683	1,567	780
Average net daily production (Boe/d)	4,611	4,281	2,137

(1) In 2011, we did not track NGLs as a separate product category; instead, NGL production was included in our natural gas production.

As reservoir pressures decline, production from a given well or formation decreases. Growth in our future production and reserves will depend on our ability to continue to add proved reserves in excess of our production. Accordingly, we plan to maintain our focus on adding reserves through increased drilling as well as acquisitions. Our ability to add reserves through development projects and acquisitions is dependent on many factors, including our ability to borrow or raise capital, obtain regulatory approvals, procure contract drilling rigs and personnel and successfully identify and consummate acquisitions. Please read Item 1A. Risk Factors Risks Related to Our Business for a discussion of these and other risks affecting our proved reserves and production.

Realized Prices on the Sale of Oil, Natural Gas and NGLs

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. Periodically, logistical and infrastructure constraints at the Cushing, Oklahoma transport hub have resulted in an oversupply of crude oil at Midland, Texas and thus lowered prices for Midland WTI. These lower prices adversely affected the prices we realized on oil sales and increased our differential to NYMEX WTI. However, several projects have recently been implemented and several more are underway, which have eased these transportation difficulties and which have reduced our differentials to NYMEX WTI to historical norms.

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.

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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.

The following table provides the high and low prices for NYMEX WTI and NYMEX Henry Hub prompt month contract prices and our differential to the average of those benchmark prices for the periods indicated. The differential varies, but our oil and natural gas normally sells at a discount to the NYMEX WTI and NYMEX Henry Hub price, respectively.

	Year Ended December 31,		
	2013	**2012**	**2011**
Oil:			
NYMEX WTI High	$ 110.53	$ 109.77	$ 113.93
NYMEX WTI Low	86.68	77.69	75.67
Differential to Average NYMEX WTI	(3.47)	(6.23)	(3.27)
Natural Gas:			
NYMEX Henry Hub High	4.46	$ 3.90	$ 4.85
NYMEX Henry Hub Low	3.11	1.91	2.99
Differential to Average NYMEX Henry Hub	(0.36)	(0.11)	(1)
NGLs:			
NGL Realized Price as a % of Average NYMEX WTI	30%	35%	(2)

(1) 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. Therefore, the average differential of realized prices to NYMEX Henry Hub is a number that is not meaningful.

(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.

In the past, oil and natural gas prices have been extremely volatile, and we expect this volatility to continue. For example, during the year ended December 31, 2013, the NYMEX WTI prompt month oil price ranged from a high of $110.53 per Bbl to a low of $86.68 per Bbl, while the NYMEX Henry Hub prompt month natural gas price ranged from a high of $4.46 per MMBtu to a low of $3.11 per MMBtu.

Due to the inherent volatility in oil 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 oil production. We have not historically hedged our natural gas production as it generally represents a small overall percentage of our total revenue. 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 oil 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 oil 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 sustain losses to the extent our derivatives contract prices are lower than market prices and, conversely, we will realize gains to the extent our derivatives contract prices are higher than market prices.

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, 2013 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 2014	December 2014	120,000	$	$	$ 96.40
January 2014	December 2015	240,000			92.60
Crude Oil Collars:					
January 2014	December 2014	384,000	87.03	110.09	
January 2014	September 2014	9,000	85.00	113.04	
January 2014	December 2015	600,000	85.00	95.00	
January 2015	December 2015	72,000	80.00	93.25	

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

Subsequent to December 31, 2013 we entered into the following oil and natural gas commodity hedges:

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 Collars:					
April 2014	December 2014	450,000	$ 85.00	$ 97.00	$
July 2014	September 2014	90,000	90.00	101.50	
October 2014	December 2014	90,000	90.00	97.33	
January 2015	March 2015	120,000	90.00	92.53	

Description & Production Period		Volume (MMBtu)	Weighted Average Floor price ($/MMBtu)(1)	Weighted Average Ceiling price ($/MMBtu)(1)	Weighted Average Swap price ($/MMBtu)(1)
Natural Gas Collars:					
April 2014	December 2014	1,350,000	$ 4.00	$ 4.78	$

(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 natural gas derivative contracts are settled based on the NYMEX closing settlement price.

Principal Components of Our Cost Structure

Lease Operating Expenses. Lease operating expenses are the costs incurred in the operation of producing properties and workover costs. Expenses for utilities, direct labor, water injection and disposal, materials and supplies comprise the most significant portion of our lease operating expenses. Lease operating expenses do not include general and administrative expenses or production or ad valorem taxes. Certain items, such as direct labor and materials and supplies, generally remain relatively fixed across broad production volume ranges, but can fluctuate depending on activities performed during a specific period. For instance, repairs to our pumping equipment or surface facilities result in increased lease operating expenses in periods during which they are performed. Certain of our operating cost components are variable and increase or decrease as the level of produced hydrocarbons and water increases or decreases. For example, we incur power costs in connection with various production related activities such as pumping to recover oil and natural gas and separation and treatment of water produced in connection with our oil and natural gas production.

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

Production and Ad Valorem Taxes. Production taxes are paid on produced oil, natural gas and NGLs based on a percentage of revenues from production sold at fixed rates established by federal, state or local taxing authorities. In general, the production taxes we pay correlate to the changes in oil, natural gas and NGL revenues. We are also subject to ad valorem taxes in the counties where our production is located. Ad valorem taxes are generally based on the valuation of our oil and natural gas properties. Where available, we benefit from tax credits and exemptions in our various taxing jurisdictions.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization (DD&A) is the systematic expensing of the capitalized costs incurred to acquire, explore and develop oil and natural gas. We use the successful efforts method of accounting for oil and natural gas activities and, as such, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts, which are then allocated to each unit of production using the unit of production method. Please read Critical Accounting Policies and Estimates Successful Efforts Method of Accounting for Oil and Natural Gas Activities for further discussion.

Impairment Expense. We review our proved properties and unproved leasehold costs for impairment whenever events and changes in circumstances indicate that a decline in the recoverability of their carrying value may have occurred. Please read Critical Accounting Policies and Estimates Impairment for further discussion.

General and Administrative Expenses. These are costs incurred for overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, audit and other fees for professional services and legal compliance. Certain of our employees hold incentive units in RSP Permian Holdco, L.L.C. that may, upon vesting, entitle the holders to a disproportionate share of future distributions to members after all of the members that have made capital contributions to RSP Permian Holdco, L.L.C. have received cumulative distributions in respect of their membership interests (including distributions made upon sales of shares of our common stock) equal to specified rates of return. These rates of return and the vesting schedule are described under Item 11. Executive Compensation Outstanding Equity Awards at 2013 Fiscal Year-End.

At such time that the occurrence of the performance conditions associated with these incentive units are deemed probable, we 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. As of December 31, 2013, the unrecognized non-cash compensation expense associated with all tiers of the incentive units is approximately $16.3 million. As a result of the successful completion of our IPO, the performance conditions associated with the Tier I, Tier I A, and Tier II incentive units are deemed probable of reaching payout, which will result in the recognition of non-cash compensation expense of approximately $11.1 million in the first quarter of 2014. The Tier I A and Tier II incentive units will have a remaining unrecognized non-cash compensation expense of approximately $1.6 million which will be amortized over the remaining service period and result in a $0.7 million non-cash compensation expense in the remainder of 2014 and $0.9 in 2015. The remaining unrecognized non-cash compensation expense related to the Tier III and Tier IV incentive units is approximately $3.5 million and will be recognized when it is deemed that the Tier III and Tier IV incentive units are probable of reaching payout as a result of reaching the established distribution thresholds. Please read Item 11. Executive Compensation Outstanding Equity Awards at 2013 Fiscal Year-End for more information on the incentive units.

Gain (Loss) on Derivative Instruments. We utilize commodity derivative contracts to reduce our exposure to fluctuations in the price of oil. None of our derivative contracts are designated as hedges for accounting purposes. Consequently, our derivative contracts are marked-to-market each quarter with fair value gains and losses recognized currently as a gain or loss in our results of operations. The amount of future gain or loss recognized on derivative instruments is dependent upon future oil prices, which will affect the value of the contracts. Cash flow is only impacted to the extent the actual settlements under the contracts result in making a payment to or receiving a payment from the counterparty.

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Interest Expense. We finance a portion of our working capital requirements and capital expenditures with borrowings under our revolving credit facility. As a result, we incur interest expense that is affected by both fluctuations in interest rates and our financing decisions. We also have a term loan outstanding that was used to partially fund our recent acquisition of the Spanish Trail Assets. We reflect interest paid to the lenders under our revolving credit facility and term loan in interest expense.

Adjusted EBITDAX

We define Adjusted EBITDAX as net income (loss) before interest expense, income taxes, depreciation, depletion and amortization, exploration expense, (gains) losses on derivative instruments excluding net cash receipts (payments) on settled derivative instruments and premiums paid on put options that settled during the period, impairment of oil and natural gas properties, non-cash equity based compensation, asset retirement obligation accretion expense, gains and losses from the sale of assets and other non-cash operating items.

Management believes Adjusted EBITDAX is useful because it allows it to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income in arriving at Adjusted EBITDAX because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDAX should not be considered as an alternative to, or more meaningful than, net income as determined in accordance with accounting principles generally accepted (GAAP) or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDAX are significant components in understanding and assessing a company s financial performance, such as a company s cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDAX. Our computations of Adjusted EBITDAX may not be comparable to other similarly titled measures of other companies.

	Predecessor			RSP Permian, Inc. Pro Forma	
	Year Ended December 31,			Year Ended December 31,	
	2013	2012	2011	2013	2012
				(Unaudited)	
			(In thousands)		
Adjusted EBITDAX reconciliation to net income:					
Net income	$ 62,738	$ 35,908	$ 131,172	$ 40,838	$ 16,440
Interest expense	5,216	3,474	3,472	10,890	8,929
Income tax expense (benefit)	2,262	(339)	550	22,717	8,554
Depreciation, depletion and amortization	47,158	48,803	16,612	80,487	65,701
Exploration expense					
Loss on derivative instruments	2,607	796	1,979	2,607	796
Net cash payments on settled derivative instruments	(886)	(474)	(856)	(886)	(474)
Premiums paid for put options that settled during the period(1)	(4,494)	(2,804)	(1,185)	(4,494)	(2,804)
Impairments			2,241		
Non-cash equity based compensation					
Asset retirement obligation accretion	121	115	46	199	162
Gain on sale of assets	(22,700)	(6,734)	(105,333)		
Adjusted EBITDAX	$ 92,022	$ 78,745	$ 48,698	$ 152,358	97,304

(1) Represents premiums paid at inception for put options that settled during the respective period.

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

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

Recent and Formation Transactions

The historical results of operations are based on the financial statements of our accounting predecessor, which reflects the combined results of RSP Permian, L.L.C. and Rising Star, prior to the corporate reorganization and the

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Transactions described under Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation Recent Events, which increased the scope of our operations.

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. These direct, incremental general and administrative expenses are not included in our historical results of operations.

Income Taxes

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

Increased Drilling Activity

Our board of directors has approved a capital budget for 2014 of $365 million. We expect that approximately 80% of our total drilling and completion expenditures in 2014 will be allocated to the drilling of horizontal wells. Our 2014 capital budget represents a 69% increase over our $216 million 2013 capital budget. The ultimate amount of capital that we expend may fluctuate materially based on market conditions and our drilling results.

Results of Operations

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

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

	Year Ended December 31, 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)	94.95	88.25	6.70	8%
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)	$ 73.37	$ 66.86	$ 6.51	10%
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%

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	Year Ended December 31, 2013	2012	$ Change	% Change
Average daily production volume:				
Oil (Bbls/d)	3,197	2,842	355	13%
Natural gas (Mcf/d)	4,375	4,305	70	2%
NGLs (Bbls/d)	685	722	(37)	(5)%
Total (Boe/d)	4,611	4,281	330	8%

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

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 the year of 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 96% for 2012 and 90% for 2013.

Oil revenues increased 21% from $91.4 million for the year ended December 31, 2012 to $110.3 million for the year ended December 31, 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. Our production from our horizontal drilling program accounted for 15% of our total production for the year ended December 31, 2013 compared to 0% for the year ended December 31, 2012. 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 the year ended December 31, 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 year ended December 31, 2012 to $7.3 million for the year ended December 31, 2013 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.

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

	Year Ended December 31, 2013	2012	$ Change	% Change
Operating expenses (in thousands, except percentages):				
Lease operating expenses	$ 14,664	$ 12,854	$ 1,810	14%
Production and ad valorem taxes	8,326	7,575	751	10%
Depreciation, depletion and amortization	47,158	48,803	(1,645)	(3)%
Exploration expense				0%
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	$ 8.71	$ 8.20	$ 0.51	6%
Production and ad valorem taxes	4.95	4.83	0.12	2%
Depreciation, depletion and amortization	28.02	31.15	(3.13)	(10)%
Exploration expense				0%
Asset retirement obligation accretion	0.07	0.07		0%
General and administrative expenses	2.29	1.82	0.47	26%
Total operating expenses per Boe	$ 44.04	46.07	$ (2.03)	(4)%

Lease Operating Expenses. Lease operating expenses increased 14% from $12.9 million for the year ended December 31, 2012 to $14.7 million for the year ended December 31, 2013. The increase in our average lease operating expenses was attributable to increased drilling activity, which resulted in additional producing wells for the year ended December 31, 2013 as compared to the year ended December 31, 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.

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

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

General and Administrative Expenses. General and administrative (G&A) expenses increased 35% from $2.9 million for the year ended December 31, 2012 to $3.9 million for the year ended December 31, 2013 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 from a $6.7 million gain for the year ended December 31, 2012 to a $22.7 million gain for the year ended December 31, 2013 as a result of the property sale to Resolute in March 2013. See Recent Events Resolute Disposition.

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Other Income and Expenses. The following table summarizes our other income and expenses for the periods 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% from $0.9 million for the year ended December 31, 2012 to $1.2 million for the year ended December 31, 2013 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, 2012, we recorded a $0.8 million loss as compared to $2.6 million loss in the year ended December 31, 2013. 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, 2012, we recorded $3.5 million of interest expense as compared to $5.2 million in the year ended December 31, 2013. 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.

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Year Ended December 31, 2012 Compared to the Year Ended December 31, 2011

Oil, Natural Gas, and NGL 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, 2012	2011	$ Change	% Change
Revenues (in thousands, except percentages):				
Oil sales	$ 91,441	$ 56,772	$ 34,669	61%
Natural gas sales(1)	4,284	7,217	NM	NM
NGL sales(1)	8,702		NM	NM
Total revenues	$ 104,427	$ 63,989	$ 40,438	63%
Average sales prices:				
Oil (per Bbl) (excluding impact of cash settled derivatives)	$ 87.92	$ 91.84	$ (3.92)	(4)%
Oil (per Bbl) (after impact of cash settled derivatives)	88.25	91.66	(3.41)	(4)%
Natural gas (per Mcf)(1)	2.72	7.44	NM	NM
NGLs (per Bbl)(1)	32.94		NM	NM
Total (per Boe) (excluding impact of cash settled derivatives)	$ 66.65	$ 82.05	$ (15.40)	$ (19)%
Total (per Boe) (after impact of cash settled derivatives)	$ 66.86	$ 81.90	$ (15.04)	$ (18)%
Production:				
Oil (MBbls)	1,040	618	422	68%
Natural gas (MMcf)(1)	1,576	971	NM	NM
NGLs (MBbls)(1)	264		NM	NM
Total (MBoe)	1,567	780	787	101%
Average daily production volumes:				
Oil (Bbls/d)	2,842	1,694	1,148	68%
Natural gas (Mcf/d)(1)	4,305	2,659	NM	NM
NGLs (Bbls/d)(1)	722		NM	NM
Total (Boe/d)	4,281	2,137	2,144	100%

(1) 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. Therefore, a comparison of revenues, sales prices and production of natural gas and NGLs between 2011 and 2012 is not meaningful.

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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 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, 2012	2011
Average realized oil price ($/Bbl)	$ 87.92	$ 91.84
Average NYMEX ($/Bbl)	94.15	95.11
Differential to NYMEX	(6.23)	(3.27)
Average realized oil price to NYMEX percentage	93%	97%
Average realized natural gas price ($/Mcf)(1)	$ 2.72	$ 7.44
Average NYMEX ($/Mcf)	2.83	4.03
Differential to NYMEX	(0.11)	(1)
Average realized natural gas price to NYMEX percentage	96%	(1)
Average realized NGL price ($/Bbl)	$ 32.94	(1)
Average NYMEX ($/Bbl)	94.15	$ 95.11
Average realized NGL price to NYMEX percentage	35%	(1)

(1) 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. Therefore, the average differential of realized prices to NYMEX Henry Hub is a number that is not meaningful.

Oil revenues increased 61% from $56.8 million in 2011 to $91.4 million in 2012 as a result of an increase in oil production volumes of 422 MBbls offset by a decrease in average oil prices of $3.92 per barrel. Of the overall change in oil sales, increases in oil production volumes accounted for a positive change of $38.8 million while decreases in oil prices accounted for a negative change of $4.1 million.

Natural gas revenues decreased from $7.2 million in 2011 to $4.3 million in 2012. During 2011, we did not track our NGL volumes as a separate product category and included NGL revenues in natural gas sales. As such, a comparison of natural gas or NGL revenues in 2011 to 2012 is not meaningful.

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

	Year Ended December 31, 2012	2011	$ Change	% Change
Operating expenses (in thousands, except percentages):				
Lease operating expenses	$ 12,854	$ 5,712	$ 7,142	125%
Production and ad valorem taxes	7,575	4,192	3,383	81%
Depreciation, depletion and amortization	48,803	16,612	32,191	194%
Exploration expense				0%
Asset retirement obligation accretion	115	46	69	150%
Impairments		2,241	(2,241)	(100)%
General and administrative expenses	2,859	3,509	(650)	(19)%

Total operating expenses before gain on sale	$ 72,206	$ 32,312	$ 39,894	123%
(Gain) on sale of assets	(6,734)	(105,333)	98,599	(94)%
Total operating expenses after gain on sale	$ 65,472	$ (73,021)	$ 138,493	190%
Average unit costs per Boe:				
Lease operating expenses	$ 8.20	$ 7.32	$ 0.88	12%
Production and ad valorem taxes	4.83	5.37	(0.54)	(10)%
Depreciation, depletion and amortization	31.15	21.30	9.85	46%
Exploration expense				0%
Asset retirement obligation accretion	0.07	0.06	0.01	17%
Impairments		2.87	(2.87)	(100)%
General and administrative expenses	1.82	4.50	(2.68)	(60)%
Total operating expenses per Boe	$ 46.07	$ 41.42	$ 4.65	11%

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Lease Operating Expenses. Lease operating expenses increased 125% from $5.7 million in 2011 to $12.9 million in 2012. This increase was primarily due to an increase in the number of operated wells due to continued drilling activity. On a per Boe basis, lease operating expense increased $0.88 per Boe to $8.20 per Boe. This increase was attributable to increases in costs for repairs and maintenance for 139 new wells added; pumpers, contract welding and administrative expense increases; gathering expense increases; and fuel and power expense increases.

Production and Ad Valorem Taxes. Production and ad valorem taxes increased 81% from $4.2 million in 2011 to $7.6 million in 2012 as a result of higher wellhead revenues, which exclude the effects of commodity derivative contracts resulting from increased production from our drilling activity and an increase in the number of wells brought on production in 2012.

Depreciation, Depletion and Amortization. DD&A expense increased 194% from $16.6 million in 2011 to $48.8 million in 2012 primarily due to an increase in production volumes by adding 139 new wells along with an increase in our asset base subject to amortization as a result of our drilling activity in 2012 and 2011. The DD&A rate per Boe increased 46% from $21.30 per Boe to $31.15 per Boe in 2012 as a result of additional drilling activity in 2012.

Impairment Expense. Impairment expense in 2011 was attributable to the annual assessed fair value of oil and natural gas properties being less than the recorded net book value.

General and Administrative Expenses. G&A expenses decreased 19% from $3.5 million in 2011 to $2.9 million in 2012. The decrease of $0.7 million is primarily a result of an increase in compensation expenses and advisory services offset by an increase in COPAS overhead reimbursement credits due to increased drilling activity.

Gain on Sale of Assets. Gain on sale of assets decreased 94% from $105.3 million gain in 2011 to $6.7 million gain in 2012 as a result of the sale in 2011 of a 25% net profits interest to ACTOIL in substantially all of our oil and natural gas properties at the time, which resulted in a larger gain as compared to the sale to Resolute in 2012. See Recent Events Resolute Disposition.

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

	Year Ended December 31, 2012	2011	$ Change	% Change
Other income (expense) (in thousands, except percentages):				
Other income	$ 884	$ 163	$ 721	442%
Loss on derivative instruments	(796)	(1,979)	1,183	60%
Interest expense	(3,474)	(3,472)	(2)	0%
Total other income (expense)	$ (3,386)	$ (5,288)	$ 1,902	36%

Other Income. Other income increased 442% from $0.2 million in 2011 to $0.9 million in 2012 as a result of income related to disposing of saltwater from third parties totaling $0.1 million in 2011 compared to $0.8 million in 2012.

Loss on Derivative Instruments. During 2011, we recognized a $2.0 million loss compared to a $0.8 million loss in 2012 on derivative instruments. The change was a result of the future commodity price outlook during 2012 as compared to 2011.

Interest Expense. The increase in interest expense is a result of an increase in the interest rate on our indebtedness offset by a decrease in the amount outstanding under our revolving credit facility.

Capital Requirements and Sources of Liquidity

Historically, our predecessor s primary sources of liquidity have been capital contributions from their equity sponsor, borrowings under RSP Permian, L.L.C. s credit facility, term loan borrowings, proceeds from asset dispositions, proceeds from the issuance of net profits interests and cash flows from operations. To date, our

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predecessor s primary use of capital has been for the acquisition, development and exploration of oil and natural gas properties.

Our 2013 capital budget for drilling, completion, recompletion and infrastructure was approximately $216 million. During 2013, we spent approximately $170 million to drill and complete operated wells, $37 million for our participation in the drilling and completion of non-operated wells and $9 million on infrastructure. Our 2014 capital budget for drilling, completion, recompletion and infrastructure is approximately $365 million. We intend to allocate our 2014 capital budget approximately as follows:

- $310 million, or 85%, for the drilling and completion of operated wells;
- $40 million, or 11%, for our participation in the drilling and completion of non-operated wells; and
- $15 million, or 4%, for infrastructure.

Because we are the operator of 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 2014 capital expenditures depending on a variety of factors, including the success of our drilling activities; prevailing and anticipated prices for oil, natural gas and NGLs; the availability of necessary equipment, infrastructure and capital; the receipt and timing of required regulatory permits and approvals; drilling, completion and acquisition costs; and the level of participation by other working interest owners.

We used a portion of the net proceeds from our IPO to fully repay our term loan and outstanding borrowings under our revolving credit facility. As of December 31, 2013, after giving effect to our IPO (including the use of proceeds therefrom) and the IPO Transactions, we would have $140 million available under our revolving credit facility. Our borrowing base under our revolving credit facility is $140 million as of December 31, 2013, and our borrowing base was increased to $300 million after our IPO.

Based upon current oil and natural gas price expectations for 2014, we believe that our cash flow from operations and additional borrowings under our revolving credit facility will provide us with sufficient liquidity to execute our current capital program.

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. We cannot assure you that operations and other needed capital will be available on acceptable terms or at all. 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 traditional reserve base borrowings, 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 $16.3 million and $54.2 million at December 31, 2013 and 2012, respectively. Our collection of receivables has historically been timely, and losses associated with uncollectible receivables have historically not been significant. Our cash balances totaled $13.2 million and $51.2 million at December 31, 2013 and 2012, 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 credit agreement will be sufficient to fund our working capital needs. We expect that our pace of development, production volumes, commodity prices and differentials to NYMEX prices for our oil and natural gas production will be the largest variables affecting our working capital.

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Contractual Obligations

A summary of our predecessor s contractual obligations as of December 31, 2013 is provided in the following table.

	Our Predecessor Payments Due by Period For the Year Ended December 31,						
	2014	**2015**	**2016**	**2017**	**2018**	**Thereafter**	**Total**
				(In thousands)			
Revolving credit facility(1)	$	$	$	$ 58,155	$	$	$ 58,155
Term loan(2)			70,000				70,000
Drilling rig commitments(3)	15,690						15,690
Office and equipment leases	653	490	372	174	178	74	1,941
Asset retirement obligations(4)						2,584	2,584
Total	$ 16,343	$ 490	$ 70,372	$ 58,329	$ 178	$ 2,658	$ 148,370

(1) This table does not include future commitment fees, amortization of deferred financing costs, interest expense or other fees on RSP Permian, L.L.C. s 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) On January 23, 2014, we repaid our term loan in full, and as of March 31, 2014, we have no contractual obligations with respect to our term loan.

(3) The values in the table represent the gross amounts that our predecessor is committed to pay.

(4) Amounts represent estimates of our predecessor s 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:

Our Predecessor Year Ended December 31,		
2013	**2012**	**2011**

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

Net cash provided by operating activities was approximately $73.3 million and $72.8 million for the years ended December 31, 2013 and 2012, respectively. Revenues increased for the year ended December 31, 2013 as compared to the year ended December 31, 2012 as a result of increased production and the Spanish Trail acquisition in 2013. However, this increase was offset by changes in other assets and liabilities and, therefore, our net cash provided by operating activities was flat during that same period.

Net cash provided by operating activities was approximately $72.8 million and $26.2 million for the years ended December 31, 2012 and 2011. Revenues increased for the year ended December 31, 2012 as compared to the year ended December 31, 2011, primarily as a result of increased production, and therefore our net cash provided by operating activities increased during that same period. Cash provided by operating activities is impacted by the prices received for oil and natural gas sales and levels of production volumes.

Net cash used in investing activities was approximately $(119.6) million and $(113.2) million for the years ended December 31, 2013 and 2012, respectively. The increase in the amount of cash used in investing activities in the year ended December 31, 2013 compared to the year ended December 31, 2012 is due to the purchase of the Spanish Trail assets for $90.4 million in September 2013 offset by $115.3 million received from the sale of properties to Resolute in March 2013.

Net cash provided by (used in) investing activities was approximately $(113.2) million and $83.8 million for the years ended December 31, 2012 and 2011, respectively. The increased amount of cash used in investing activities in

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the year ended December 31, 2012 was due to $174.0 million spent on drilling and development of our properties in 2012 partially offset by $63.2 million of proceeds from the sale of properties to Resolute compared to $95.7 million spent on drilling and developing our properties in 2011, offset by $175 million of proceeds from the sale of a 25% net profits interest to ACTOIL in substantially all of our oil and natural gas properties at the time.

Net cash provided by financing activities was approximately $8.2 million and $81.6 million for the years ended December 31, 2013 and 2012, respectively. For the year ended December 31, 2013, the decreased cash provided by financing activities was primarily the result of incremental borrowings under long-term debt of $11.6 million offset by long-term debt repayments of $85.0 million and capital distributions of $30.0 million. For the year ended December 31, 2012, the cash provided by financing activities included $90.0 million in borrowings.

Net cash provided by (used in) financing activities was approximately $81.6 million and $(105.2) million for the years ended December 31, 2012 and 2011, respectively. For 2012, the increased cash provided by financing activities included $90.0 million of borrowings offset by debt repayments of $25.0 million. For 2011, the cash used in financing activities primarily related to debt repayments of $160.0 million offset by $55.1 million in borrowings.

Our Revolving Credit Facility

On September 10, 2013, RSP Permian, L.L.C. entered into a credit agreement with Comerica Bank, as administrative agent, and a syndicate of lenders for a revolving credit facility with commitments of $500 million, subject to a borrowing base of $140 million, and a sublimit for letters of credit of $10 million, as well as a term loan in an aggregate principal amount of $70 million.

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 and estimated cash flows from these reserves and our commodity hedge positions. As of December 31, 2013, we had $56.2 million of borrowings and $0.6 million of letters of credit outstanding under our revolving credit facility. Our revolving credit facility matures September 10, 2017. The term loan matures on April 1, 2016.

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;
- a minimum interest coverage ratio, which is the ratio of consolidated EBITDAX (as defined in our revolving credit facility) to consolidated interest expense, of not less than 3.0 to 1.0 as of December 31, 2013; and
- a leverage ratio, which is the ratio of the sum of all our debt to the consolidated EBITDAX (as defined in our revolving credit facility) for the four fiscal quarters then ended, of not greater than 4.0 to 1.0.

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We were in compliance with such covenants and ratios as of December 31, 2013.

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. At December 31, 2013, the variable rate of interest under our revolving credit facility was 1.67%. We may repay any amounts borrowed prior to the maturity date without any premium or penalty other than customary LIBOR breakage costs.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our combined financial statements, which have been prepared in accordance with U.S. GAAP. 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 combined 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 activities in 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, amortization and impairment of unproved leasehold 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.

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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 leasehold costs may be assessed in the aggregate. If unproved leasehold costs are found to be impaired, an impairment allowance is provided and a loss is recognized in the statement of operations.

Depreciation, depletion and amortization

Depreciation, depletion and amortization of capitalized costs of proved oil and natural gas properties is computed using the unit-of-production method on a field basis based upon total estimated proved reserves. The reserve base used to calculate depreciation, depletion and amortization for leasehold acquisition costs and the cost to acquire proved properties is the sum of proved developed reserves and proved undeveloped reserves. The reserve base used to calculate depreciation, depletion and amortization for drilling, completion and well equipment costs, which include development costs and successful exploration drilling costs, includes only proved developed reserves.

Revenue recognition

We recognize oil, natural gas and NGL revenues when products are delivered at a fixed or determinable price, title has transferred and collectability is reasonably assured (sales method). Oil and natural gas sold is not significantly different from our share of production.

Derivative financial instruments

We use derivative contracts to hedge the effects of fluctuations in the prices of oil. We record such derivative instruments as assets or liabilities in the statements of financial position (see Note 4 of the accompanying Notes to Combined Financial Statements included in Item 8. Financial Statements and Supplementary Data for further information on fair value). Estimating the fair value of derivative financial instruments requires management to make estimates and judgments regarding volatility and counterparty credit risk.

We have not designated any of our derivative contracts as fair value or cash flow hedges. The changes in fair value of the contracts are included in other income (expense) in the period of the change.

Acquisitions

As part of our business strategy, we periodically pursue the acquisition of oil and natural gas properties. The purchase price in an acquisition is allocated to the assets acquired and liabilities assumed based on their relative fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. Our most significant estimates in our allocation typically relate to the value assigned to future recoverable oil and natural gas reserves and unproved properties. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain.

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Asset retirement obligations

We recognize as a liability an asset retirement obligation (ARO) associated with the retirement of a tangible long-lived asset in the period in which it is incurred or becomes determinable (as defined by the standard), with an associated increase in the carrying amount of the related long-lived asset. The cost of the tangible asset, including the initially recognized asset retirement cost, is depreciated over the useful life of the asset and accretion expense is recognized over time as the discounted liability is accreted to its expected settlement value. We measure the fair value of the ARO using expected future cash outflows for abandonment discounted back to the date that the abandonment obligation was measured using an estimated credit adjusted rate.

Estimating the future ARO requires management to make estimates and judgments regarding timing and existence of a liability, as well as what constitutes adequate restoration. Inherent in the fair value calculation are numerous assumptions and judgments including the ultimate costs, inflation factors, credit adjusted discount rates, timing of settlement and changes in the legal, regulatory, environmental and political environments. To the extent future revisions to these assumptions impact the fair value of the existing ARO liability, a corresponding adjustment is made to the related asset.

Recently Issued Accounting Pronouncements

The FASB issued ASU 2011-11, *Disclosures about Offsetting Assets and Liabilities* in December 2011, and issued ASU 2013-01, *Clarifying the Scope of Disclosures About Offsetting Assets and Liabilities* in January 2013. These ASUs create new disclosure requirements regarding the nature of an entity s rights of setoff and related arrangements associated with its derivative instruments, repurchase agreements and securities lending transactions. Certain disclosures of the amounts of certain instruments subject to enforceable master netting arrangements would be required, irrespective of whether the entity has elected to offset those instruments in the statement of financial position. These ASUs are effective retrospectively for annual reporting periods beginning on or after January 1, 2013. The adoption of these ASUs will not impact the predecessor s financial position, results of operations or liquidity.

Off-Balance Sheet Arrangements

As of December 31, 2013, we did not have any off-balance sheet arrangements.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Commodity Price Risk

Our revenues are subject to market risk and are dependent on the pricing that we receive for our oil, natural gas and NGL production. Pricing for oil, natural gas and NGLs 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 natural gas and NGLs. Our predecessor has used, and we expect to continue to 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.

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Our open positions as of December 31, 2013 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 2014	December 2014	120,000	$	$	$ 96.40
January 2014	December 2015	240,000			92.60
Crude Oil Collars:					
January 2014	December 2014	384,000	87.03	110.09	
January 2014	September 2014	9,000	85.00	113.04	
January 2014	December 2015	600,000	85.00	95.00	
January 2015	December 2015	72,000	80.00	93.25	

(1) The 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, 2013 was a net asset of $0.1 million. For information regarding the terms of these hedges, see Item 7. Management s Discussion and Analysis of Financial Conditions and Results of Operations How We Evaluate Our Operations Realized Prices on the Sale of Oil, Natural Gas and NGLs above.

Counterparty and Customer Credit Risk

Our oil derivative contracts expose us to credit risk in the event of nonperformance by counterparties. While our predecessor does not require our counterparties to our derivative contracts to post collateral, our predecessor does evaluate the credit standing of such counterparties as it deems appropriate. We plan to continue to evaluate the credit standings of our counterparties in a similar manner. The counterparties to our predecessor s derivative contracts currently in place have investment grade ratings.

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

Joint operations receivables arise from billings to entities that own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we intend to drill. We have little ability to control whether these entities will participate in our wells.

Interest Rate Risk

At December 31, 2013, our predecessor had $128.2 million of debt outstanding, with an assumed weighted average interest rate of 4.4%. Assuming no change in the amount outstanding, the impact on interest expense of a 1.0% increase or decrease in the assumed weighted average interest rate would be approximately $1.3 million per year. The adjusted LIBOR rate applicable to our predecessor s term loan may not be lower than 1.0%.

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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.

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, 2013. 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, 2013 at the reasonable assurance level.

Management s Report on Internal Control Over Financial Reporting

This Report does not include a report on management s assessment regarding internal control over financial reporting due to a transition period established by the rules of the SEC for newly public companies.

Attestation Report of the Registered Public Accounting Firm

This Report does not include an attestation report of our independent registered public accounting firm due to a transition period established by the rules of the SEC for newly public companies. Further, 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 JOBS Act.

Changes in Internal Control over Financial Reporting

As described above, there were 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, 2013 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

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PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The following table sets forth the names, ages and titles of our directors and executive officers as of March 31, 2014.

Name	Age	Position
Michael Grimm	59	Chairman of the Board
Steven Gray	54	Chief Executive Officer and Director
Scott McNeill	42	Chief Financial Officer and Director
David Albin	54	Director
Joseph B. Armes	52	Director
Ted Collins, Jr.	75	Director
Matthew S. Ramsey	59	Director
Michael W. Wallace	50	Director
Zane Arrott	56	Chief Operating Officer
Tamara Pollard	52	Vice President of Planning and Reserves
Erik B. Daugbjerg	44	Vice President of Oil & Gas Marketing/Business Development
William Huck	58	Vice President, Operations

Set forth below is a description of the backgrounds of our directors and executive officers.

Michael Grimm, Chairman of the Board, co-founded RSP Permian, L.L.C. in 2010 and has served as our Chairman of the Board since our formation. Prior to being named our Chairman of the Board, Mr. Grimm served as RSP Permian, L.L.C. s Co-Chief Executive Officer. From 2006 to present, Mr. Grimm has served as President and Chief Executive Officer of Rising Star, and from 1995 to 2006, Mr. Grimm served as President and Chief Executive Officer of Rising Star Energy, L.L.C., which he co-founded in 1995. From 1990 to 1994, Mr. Grimm served as Vice President of Worldwide Exploration and Land for Placid Oil Company. Prior to that, Mr. Grimm was employed for 13 years in the land and exploration department for Amoco Production Company in Houston, New Orleans and Chicago. Mr. Grimm has more than 35 years of experience in the oil and natural gas industry and currently serves as a Director for Rising Star, Rising Star Petroleum, L.L.C. and Energy Transfer Partners, L.P. He has a B.B.A. from the University of Texas at Austin.

Mr. Grimm has significant experience as a chief executive of oil and natural gas exploration and production companies and broad knowledge of the oil and natural gas industry. We believe his background and skill set enables Mr. Grimm to provide our board of directors with executive counsel on a full range of business, strategic and professional matters.

Steven Gray, Director and Chief Executive Officer, co-founded RSP Permian, L.L.C. in 2010. He has served as our Chief Executive Officer and as a member of our board of directors since our formation and has served RSP Permian, L.L.C. as Co-Chief Executive Officer since its inception in 2010. In 2007, Mr. Gray co-founded Pecos with Messrs. Daugbjerg and Huck. In 2000, Mr. Gray co-founded Pecos Production Company, an NGP-backed oil and natural gas exploration and production company that operated in the Permian Basin until it was sold in 2005 to Chesapeake Energy Corporation. Mr. Gray continues to serve as a manager of Pecos Operating Company, LLC, Pecos s general partner. From 1993 to 2000, Mr. Gray was a Co-Founder, President and Chief Operating Officer of Vista Energy Resources, an NGP-backed oil and natural gas exploration and production company. Prior to forming Vista, Mr. Gray was employed for 11 years as a petroleum engineer with Bettis, Boyle, and Stovall, Inc. and Texas Oil & Gas Corp. He received a B.S. in Petroleum Engineering from Texas Tech University and has more than 30 years of experience in the oil and natural gas industry.

Mr. Gray has significant experience as a chief executive officer and chief operating officer of oil and natural gas exploration and production companies and broad knowledge of the oil and natural gas industry. We believe his background and skill set enables Mr. Gray to provide our board of directors with executive counsel on a full range of business, strategic and professional matters.

Scott McNeill, Director and Chief Financial Officer, has served as our Chief Financial Officer since our formation and as a member of our board of directors since December 2013. Mr. McNeill has served RSP Permian, L.L.C. as Chief Financial Officer since April 2013. Prior to joining the company, Mr. McNeill served as a Managing

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Director in the energy investment banking group of Raymond James. Mr. McNeill spent 15 years as an investment banker advising a wide spectrum of companies operating in the exploration and production, midstream, and energy service and equipment segments of the energy industry. Mr. McNeill is licensed as a Certified Public Accountant. He earned a B.B.A. from Baylor University and an M.B.A. from the University of Texas at Austin.

Mr. McNeill has significant experience with energy companies and investments and broad knowledge of the oil and natural gas industry as well as significant expertise in finance. We believe his background and skill set make Mr. McNeill well-suited to serve as a member of our board of directors.

David Albin, Director, has served as a member of our board of directors since our formation. Mr. Albin is a co-founder and senior partner of NGP and has served in that or similar capacities since 1988. He also serves as a director of NGP Capital Resources Company. Prior to his participation as a founding member of NGP, Mr. Albin was a partner in the $600 million Bass Investment Limited Partnership, and prior to joining Bass Investment Limited Partnership, he was a member of the oil and natural gas group in the investment banking division of Goldman, Sachs & Co. From 2004 through the second quarter of 2012, Mr. Albin served as a director of Energy Transfer Partners, LP and LE GP, LLC, the general partner of Energy Transfer Equity, L.P., and continues to serve on the board of numerous other private companies. Mr. Albin received a B.S. in Physics in 1981 and an M.B.A. in 1985 from Stanford University.

Mr. Albin has significant experience with energy companies and investments and broad knowledge of the oil and natural gas industry as well as significant expertise in finance. We believe his background and skill set make Mr. Albin well-suited to serve as a member of our board of directors.

Joseph B. Armes, Director, has served as a member of our board of directors since December 2013. Since June 2013, Mr. Armes has served as President, Chief Executive Officer and a member of the board of directors of Capital Southwest Corporation, a publicly-traded investment company. Since 2010, Mr. Armes served as President and Chief Executive Officer of JBA Investment Partners, a family investment vehicle. From 2005 to 2010, Mr. Armes served as Chief Operating Officer of Hicks Holdings, LLC. Prior to 2005, Mr. Armes served as Executive Vice President and General Counsel and later as Chief Financial Officer of Hicks Sports Group, LLC, as Executive Vice President and General Counsel of Suiza Foods Corporation (now Dean Foods Company) and Vice President and General Counsel of The Morningstar Group Inc. In addition, from 2007 to 2009, Mr. Armes served as a director of Hicks Acquisition Co. I, a publicly-traded acquisition company. Mr. Armes received a B.B.A. in Finance, an M.B.A. from Baylor University and a J.D. from Southern Methodist University.

Mr. Armes has significant experience as an executive officer and director in a variety of public companies and an extensive background in strategic investing. We believe his background and skill set make Mr. Armes well-suited to serve as a member of our board of directors.

Ted Collins, Jr., Director, has served as a member of our board of directors since January 2014. Mr. Collins has been an independent oil and gas producer since 2000. He served as Chairman and Chief Executive Officer of Patriot Resources Partners, LLC from 2007 to 2010 and as President of Collins & Ware Inc. from 1988 to 2000, when its assets were sold to Apache Corporation. From 1982 to 1988, Mr. Collins was President of the predecessors of EOG Resources, and HNG Oil Company, HNG Internorth Exploration Co. and Enron Oil and Gas Company. From 1969 to 1982, Mr. Collins served as Executive Vice President of American Quasar Petroleum Company. Since 2011, Mr. Collins has served as a director of Oasis Petroleum, Inc. and as a member of its audit committee and nominating and governance committee. In addition, Mr. Collins has served as a director of the general partner of Energy Transfer Partners, L.P. since 2004 and as a director of CLL Global Research Foundation since 2009. Mr. Collins is also the chairman of the board of managers of Coronado Midstream, LLC (formerly named MidMar Gas, LLC). Mr. Collins is a past President of the Permian Basin Petroleum Association, the Permian Basin Landmen s Association, the Petroleum

Club of Midland and has served as Chairman of the Midland Wildcat Committee since 1984. Mr. Collins received a B.S. in Geological Engineering from the University of Oklahoma.

Mr. Collins has significant experience as an independent operator and as an executive officer in various positions and a director of oil and gas companies and has broad knowledge of the oil and gas industry. We believe his background and skill set enables Mr. Collins to provide our board of directors with executive counsel on a full range of business, strategic and professional matters.

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Matthew S. Ramsey, Director, has served as a member of our board of directors since January 2014. Since 2000, Mr. Ramsey has served RPM Exploration, Ltd., a private oil and gas exploration limited partnership generating and drilling 3-D seismic prospects on the Gulf Coast of Texas, as President and a member of the board of directors of its general partner, Ramsey, Pawelek & Maloy, Inc. Currently, Mr. Ramsey also serves as President of Ramsey Energy Management, LLC, the general partner of Ramsey Energy Partners, I, Ltd., a private oil and gas partnership; President of Dollarhide Management, LLC, the general partner of Deerwood Investments, Ltd., a private oil and gas partnership; President of Gateshead Oil, LLC, a private oil and gas partnership; and Manager of MSR Energy, LLC, the general partner of Shafter Lake Energy Partners, Ltd., a private oil and gas partnership. Previously, Mr. Ramsey served as President of DDD Energy, Inc. from 2001 until its sale in 2002; President, Chief Executive Officer and a member of the board of directors of OEC Compression Corporation, a publicly-traded oil field service company, from 1996 to 2000; and Vice President of Nuevo Energy Company, an independent energy company, from 1991 to 1996. Additionally, from 1990 to 1996, he was employed by Torch Energy Advisors, Inc., a company providing management and operations services to energy companies, where he last served as Executive Vice President. Since July 2012, Mr. Ramsey has served as a member of the board of director of LE GP, LLC, the general partner of Energy Transfer Equity, L.P., and as a member of its audit and compensation committees. From March 2012 to July 2012, Mr. Ramsey served as a member of the board of directors of Southern Union Company. Mr. Ramsey holds a B.B.A. in Marketing from the University of Texas at Austin and a J.D. from South Texas College of Law. Mr. Ramsey is a graduate of the Harvard Business School Advanced Management Program.

Mr. Ramsey has significant experience as an executive officer and director in a variety of oil and gas companies and has broad knowledge of the oil and gas industry. We believe his background and skill set make Mr. Ramsey well-suited to serve as a member of our board of directors.

Michael W. Wallace, Director, has served as a member of our board of directors since January 2014. Since 2011 Mr. Wallace has been a partner and manager of Wallace Family Partnership, LP, which holds non-operated working interests in oil and gas leases, midstream assets and other investments. Since 2009, Mr. Wallace has also served as the President, director and manager of High Sky Partners LLC, a Midland, Texas-based oil and gas company with operations in the Spraberry Trend of the Permian Basin. From 2007 to 2011, Mr. Wallace was a member and Executive Vice President of Production for Patriot Resource Partners LLC. In 2004, Mr. Wallace founded Flying W Resources, LLC, an independent oil and gas production company. In addition, Mr. Wallace served in a variety of technical and managerial roles within Conoco Inc. and ConocoPhillips Company from 2001 to 2004. Prior to joining Conoco Inc., Mr. Wallace served in a variety of roles within Burlington Resources Inc. Mr. Wallace received a B.S. in Petroleum Engineering from Texas Tech University and is a member of the Society of Petroleum Engineers.

Mr. Wallace has significant experience as an independent operator and as an executive officer in various positions of oil and gas companies and has broad knowledge of the oil and gas industry. We believe his background and skill set enables Mr. Wallace to provide our board of directors with executive counsel on a full range of business, strategic and professional matters.

Zane Arrott, Chief Operating Officer, has served as our Chief Operating Officer since our formation and has served RSP Permian, L.L.C. in such capacity since its inception in 2010. Since 1995, Mr. Arrott has served as the Chief Operating Officer for Rising Star and continues to serve on the boards of Rising Star and Rising Star Petroleum, L.L.C. From 1982 to 1995, Mr. Arrott held several positions with Placid Oil Company and was elevated to General Manager of its Canadian Division in 1988. Mr. Arrott has more than 32 years of experience in the oil and natural gas industry and extensive experience with reservoir engineering, production engineering, project economic forecasting and reserve acquisitions. He has a B.S. in Petroleum Engineering from Texas Tech University.

Tamara Pollard, Vice President of Planning and Reserves, has served as our Vice President of Planning and Reserves since our formation and has served RSP Permian, L.L.C. in such capacity since its inception in 2010. Since 1998, Ms. Pollard has held several positions with Rising Star Energy, L.L.C., most recently as Vice President of Financial Planning and Reserves, Secretary and Treasurer. From 1995 to 1998, Ms. Pollard was employed by Lovegrove & Associates and Oryx Energy. From 1985 to 1995, Ms. Pollard held several positions at Placid Oil Company and worked as a reservoir engineer until 1992 when she was elevated to Manager of Planning and Business Development. She has over 25 years of oil and gas experience and has as B.S. in Petroleum Engineering from the University of Tulsa and an M.B.A. from the University of Texas at Arlington.

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Erik B. Daugbjerg, Vice President of Oil & Gas Marketing/Business Development, has served as our Vice President of Oil & Gas Marketing/Business Development since our formation and has served RSP Permian, L.L.C. in such capacity since its inception in 2010. In 2007 Mr. Daugbjerg co-founded Pecos with Messrs. Gray and Huck, and he continues to serve as a manager of Pecos Operating Company, LLC, Pecos s general partner. Mr. Daugbjerg served as President of Pecos River Operating Company, an exploration and production company with operations in southeast New Mexico, from 2000 until is sale in 2005. From 1997 to 2000, Mr. Daugbjerg served as Vice President of Producer Services for Highland Energy Company. From 1992 to 1996, he served in various roles with Hadson Corporation, an oil and natural gas marketing and midstream company with operations in the Permian Basin. Mr. Daugbjerg has more than 20 years of experience in the energy industry and has a B.B.A. from Southern Methodist University.

William Huck, Vice President, Operations, co-founded RSP Permian, L.L.C. in 2010. He has served as our Vice President, Operations since our formation and served RSP Permian, L.L.C. in such capacity since its inception. In 2007, Mr. Huck co-founded Pecos with Messrs. Daugbjerg and Gray, and he continues to serve as a manager of Pecos Operating Company, LLC, Pecos s general partner. Mr. Huck co-founded Pecos Production Company in 2000 and served as its Vice President Production until it was sold to Chesapeake Energy Corporation in 2005. In addition, he serves as President of Huck Engineering, Inc. From 1998 to 2000, Mr. Huck served as an Operating Manager for Collins & Ware, Inc., an oil and natural gas production company in Midland, Texas. From 1994 to 1998, Mr. Huck operated an independent engineering consulting firm, Huck Engineering, Inc. Mr. Huck has more than 30 years of oil and natural gas experience and has a B.S. in Petroleum Engineering from Marietta College.

Director Independence

Our board of directors currently consists of eight members: Michael Grimm, Steven Gray, Scott McNeill, David Albin, Joseph B. Armes, Ted Collins, Jr., Matthew S. Ramsey and Michael W. Wallace. Our board of directors has determined that Messrs. Albin, Armes, Collins, Ramsey and Wallace are independent as defined by the rules of the NYSE and under Rule 10A-3 promulgated under the Exchange Act.

Committees of the Board of Directors

We have an audit committee, a compensation committee and a nominating and corporate governance committee of our board of directors, and may have such other committees as our board of directors shall determine from time to time. Each of the standing committees of our board of directors have the composition and responsibilities described below.

Audit Committee

Rules implemented by the NYSE and SEC require us to have an audit committee comprised of at least three directors who meet the independence and experience standards established by the NYSE and the Exchange Act, subject to transitional relief during the one-year period following the completion of our IPO. Our audit committee consists of Messrs. Armes (Chair) and Ramsey, each of whom is independent under the rules of the SEC. Subsequent to the transitional period, we will comply with the requirement to have three independent directors on our audit committee. As required by the rules of the SEC and listing standards of the NYSE, the audit committee consists solely of independent directors. Our board of directors has determined that Messrs. Armes and Ramsey satisfy the definition of audit committee financial expert.

This committee oversees reviews acts on and reports on various auditing and accounting matters to our board of directors, including: the selection of our independent accountants, the scope of our annual audits, fees to be paid to the independent accountants, the performance of our independent accountants and our accounting practices. In addition, the audit committee oversees our compliance programs relating to legal and regulatory requirements. We have an audit committee charter defining the committee s primary duties in a manner consistent with the rules of the SEC and applicable stock exchange or market standards. A copy of our audit committee charter is posted on the Company s website at http://rsppermian.investorroom.com/committee-charters.

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Compensation Committee

Our compensation committee establishes salaries, incentives and other forms of compensation for officers and other employees. Our compensation committee also administers our incentive compensation and benefit plans. Our compensation committee charter defines the committee s primary duties in a manner consistent with the rules of the SEC and applicable stock exchange or market standards.

Our compensation committee consists of Messrs. Ramsey (Chair), Albin and Armes, each of whom are independent under the rules of the NYSE. A copy of our compensation committee charter is posted on the Company s website at http://rsppermian.investorroom.com/committee-charters.

Nominating and Corporate Governance Committee

Our nominating and corporate governance committee identifies, evaluates and recommends qualified nominees to serve on our board of directors, develops and oversees our internal corporate governance processes and maintains a management succession plan. Our nominating and corporate governance committee charter defines the committee s primary duties in a manner consistent with the rules of the SEC and applicable stock exchange or market standards.

Our nominating and governance committee consists of Messrs. Collins (Chair), Albin, Armes, Ramsey and Wallace. A copy of our nominating and corporate governance committee charter is posted on the Company s website at http://rsppermian.investorroom.com/committee-charters.

Executive Sessions of Non-Management Directors

Our board of directors holds regular executive sessions in which the independent directors meet without any non-independent directors or members of management. The purpose of these executive sessions is to promote open and candid discussion among the independent directors. The chairman presides at these meetings and provides our board of directors s guidance and feedback to our management team.

Communication with our Board of Directors

Stockholders or other interested parties who wish to communicate with the directors may do so by sending communications to our board of directors, any committee of our board of directors, the chairman of our board of directors or any other director to the address or phone number appearing on the front page of this Report by marking the envelope containing each communication as Communication with Directors and clearly identifying the intended recipient(s) of the communication. Communications will be relayed to the intended recipient of our board of directors.

Corporate Governance Matters

We have a Code of Business Conduct and Ethics that applies to our directors, officers and employees as well as a Financial Code of Ethics that applies to our Chief Executive Officer, Chief Financial Officer, controller and the other senior financial officers, each as required by SEC and NYSE rules. Furthermore, we have Corporate Governance Guidelines and a charter for our Audit Committee. Each of the foregoing is available on our website at www.rsppermain.com in the Corporate Governance section. We will provide copies, free of charge, of any of the foregoing upon receipt of a written request to RSP Permian, Inc., 3141 Hood Street, Suite 500, Dallas, Texas 75219, Attn: Investor Relations. We intend to disclose amendments to and waivers from our Financial Code of Ethics, if any, on our website promptly following the date of any such amendment or waiver.

Section 16(a) Beneficial Ownership Reporting Compliance

The executive officers and directors of the Company and persons who own more than 10% of a class of our equity securities registered pursuant to Section 12 of the Exchange Act to file certain reports with the SEC, disclosing the amount and nature of their beneficial ownership in common stock, as well as changes in that ownership. We had no equity securities registered pursuant to Section 12 of the Exchange Act during the year ended December 31, 2013 and, as a result, no such reports were required to be filed.

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Section 16(a) of the Exchange Act requires our directors and executive officers, and persons who own more than 10% of a registered class of our equity securities, to file reports of beneficial ownership on Form 3 and reports of changes in beneficial ownership on Form 4 or Form 5 with the SEC. Based solely on our review of the reporting forms and written representations provided to us from the individuals required to file reports, we believe that all filings by such persons were made on a timely basis during the fiscal year ended December 31, 2013, except as discussed below. On January 21, 2014, Mr. Collins wife purchased shares of our common stock, and a Form 4 reporting such purchase was not filed by Mr. Collins until January 27, 2014.

ITEM 11. EXECUTIVE COMPENSATION

Named Executive Officers

We are currently considered an emerging growth company for purposes of the SEC s executive compensation disclosure rules. In accordance with such rules, we are required to provide a Summary Compensation Table and an Outstanding Equity Awards at Fiscal Year End Table, as well as limited narrative disclosures. Further, our reporting obligations extend only to the individuals serving as our chief executive officers, and our two other most highly compensated executive officers. For fiscal year 2013, our named executive officers were:

Name	Principal Position
Michael Grimm	Chief Executive Officer
Steven Gray	Chief Executive Officer
Scott McNeill	Chief Financial Officer
Zane Arrott	Chief Operating Officer
Tamara Pollard	Vice President of Planning and Reserves
William Huck	Vice President, Operations

Messrs. Grimm and Gray served as co-Chief Executive Officers during the 2013 fiscal year. Messrs. Arrott and Huck and Ms. Pollard were paid the same amount of compensation for the 2013 year, thus we have disclosed three officers in addition to Mr. McNeill rather than the one additional officer that would have been necessary for disclosure under the emerging growth company disclosure rules.

Summary Compensation Table

The following table summarizes, with respect to our named executive officers, information relating to the compensation earned for services rendered in all capacities during the fiscal years ended December 31, 2013 and 2012.

Name and Principal Position	Year	Salary($)	Bonus ($)(1)	Option Awards ($)(2)	Total ($)(3)
Michael Grimm	2013	225,000	50,000	N/A	275,000
(Chief Executive Officer)	2012	225,000	N/A	N/A	225,000

Steven Gray	2013	225,000	50,000	N/A	275,000
(Chief Executive Officer)	2012	225,000	N/A	N/A	225,000
Scott McNeill	2013	300,000	N/A	0	300,000
(Chief Financial Officer)					
Zane Arrott	2013	225,000	50,000	N/A	275,000
(Chief Operating Officer)	2012	225,000	N/A	N/A	225,000
Tamara Pollard	2013	225,000	50,000	N/A	275,000
(Vice President of Planning and Reserves)	2012	225,000	N/A	N/A	225,000
William Huck	2013	225,000	50,000	N/A	275,000
(Vice President, Operations)	2012	225,000	N/A	N/A	225,000

(1) Each of the named executive officers (other than Mr. McNeill) received a discretionary bonus for the 2013 year. The amounts were paid in the first quarter of 2014.

(2) Mr. McNeill received a grant of Tier I A incentive units at the time that he began his employment in 2013. We believe that, despite the fact that the incentive units do not require the payment of an exercise price, they are most similar economically to stock options, and as such, they are properly classified as options under the definition provided in Item 402(a)(6)(i) of Regulation S-K as an instrument with an option-like feature. Amounts reflected in this column for Mr. McNeill reflect a

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grant date fair value of the incentive units in accordance with FASB ASC Topic 718 of $0. Because the performance conditions related to these awards were not deemed probable at the time of grant in 2013, no amounts have been reported in 2013 for purposes of this table. While the awards do not have target or maximum payout levels, the maximum amount of compensation cost that we believe could have been reported on the grant date under FASB ASC Topic 718 had the performance conditions been deemed probable would have been $1.1 million.

(3) None of the individuals serving as our named executive officers during the 2012 year received compensation other than base salary during the 2012 fiscal year.

Outstanding Equity Awards at 2013 Fiscal Year-End

The awards reported here reflect the incentive units, or profits interest awards, that each named executive officer held as of December 31, 2013. Prior to our IPO, the incentive units were profits interests, rather than capital interests, in us. In connection with our IPO, the profits interest awards became incentive units, or profits interest awards, in RSP Permian Holdco, L.L.C., although the terms and conditions of the profits interest awards remained substantially similar to the terms applicable to the profits interest awards prior to our IPO, including the retention of existing vesting schedules. Where terms were modified following our IPO, they have been described in the narrative below. As a result of and following our IPO, the profits interest awards held by the named executive officers described in the following table no longer relate directly to our securities, and we will not be financially or otherwise responsible for distributions or settlements relating to such profits interest awards.

Name	**Number of Securities Underlying Unexercised Options, Unexercisable (#)(1)**	**Number of Securities Underlying Unexercised Option, Exercisable (#)(1)**	**Option Exercise Price ($)(1)**	**Option Expiration Date(1)**
Michael Grimm(2)				
Tier I Units	0	133,333	N/A	N/A
Tier II Units	133,333	0	N/A	N/A
Tier III Units	133,333	0	N/A	N/A
Tier IV Units	133,333	0	N/A	N/A
Steven Gray(3)				
Tier I Units	0	180,000	N/A	N/A
Tier II Units	180,000	0	N/A	N/A
Tier III Units	180,000	0	N/A	N/A
Tier IV Units	180,000	0	N/A	N/A
Scott McNeill				
Tier I A Units	100	0	N/A	N/A
Zane Arrott(4)				
Tier I Units	0	133,333	N/A	N/A
Tier II Units	133,333	0	N/A	N/A
Tier III Units	133,333	0	N/A	N/A
Tier IV Units	133,333	0	N/A	N/A
Tamara Pollard(5)				
Tier I Units	0	128,333	N/A	N/A

Tier II Units	128,333	0	N/A	N/A
Tier III Units	128,333	0	N/A	N/A
Tier IV Units	128,333	0	N/A	N/A
William Huck				
Tier I Units	0	140,000	N/A	N/A
Tier II Units	140,000	0	N/A	N/A
Tier III Units	140,000	0	N/A	N/A
Tier IV Units	140,000	0	N/A	N/A

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(1) We believe that, despite the fact that the profit units do not require the payment of an exercise price, they are most similar economically to stock options, and as such, they are properly classified as options under the definition provided in Item

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402(a)(6)(i) of Regulation S-K as an instrument with an option-like feature. The profits interest awards are divided into five tiers each of which has a separate distributions threshold and vesting schedule. Awards reflected as Unexercisable are incentive units that have not yet vested. The Tier I A units for Mr. McNeill will vest in three equal annual installments beginning on the grant date of April 1, 2013. The Tier II, Tier III and Tier IV units in the Unexercisable column will not become vested until such time as the distributions threshold for that Tier has been satisfied. Awards reflected as Exercisable are profits interest awards that have vested, but have not yet been settled. For a description of how and when the profits interest awards could become vested and when such awards could begin to receive payments, see the discussion below.

(2) Each of the incentive units reported in the table above for Mr. Grimm have been transferred, without value, to a family partnership titled the Grimm Family Limited Partnership. Mr. Grimm will still be deemed to beneficially own the incentive units reported in the table through this family partnership.

(3) The incentive units reported in the table above for Mr. Gray have been irrevocably transferred, without value, to the Steven D. Gray and Debora K. Gray 2012 GST Exempt Trust and the Steven D. Gray GRAT No. 2005-1, trusts maintained solely for the benefit of Mr. Gray s children or grandchildren. He is not deemed to have beneficial ownership over any of the incentive units reported in the table, but they are reported above due to the fact that the grant of the awards were considered to be compensatory awards to Mr. Gray at the time of grant.

(4) Each of the incentive units reported in the table above for Mr. Arrott have been transferred, without value, to a family partnership titled Arrott Family Holdings, L.P. Mr. Arrott will still be deemed to beneficially own the incentive units reported in the table through this family partnership.

(5) Each of the incentive units reported in the table above for Ms. Pollard have been transferred, without value, to a family partnership titled Pollard Resource Holdings, LP. Ms. Pollard will still be deemed to beneficially own the incentive units reported in the table through this family partnership.

Narrative to the Outstanding Equity Awards Table

We granted profits interest awards to each of the named executive officers in order to provide them with the ability to benefit from the growth in our operations and business. The profits interest awards are divided into five tiers. A potential payout for each tier will occur only after a specified level of cumulative cash distributions has been received by members that have made capital contributions to us, as further described below. Tier I and I A units are designed to vest in three equal annual installments, although vesting will be fully accelerated if a Fundamental Change (as defined below) occurs prior to the time-based vesting becoming satisfied. The Tier I units granted to the applicable named executive officers in 2010 became fully time-vested on October 18, 2013. Tier II units, Tier III units and Tier IV units will each vest only upon the distribution threshold established for that tier (described below). The difference between a vested and unvested unit is that once a unit is vested, in the event that an executive s employment terminates other than for Cause or due to a voluntary termination by such executive, the executive may retain all vested profits interest awards as non-voting interests. All profits interest awards that have not vested according to their original vesting schedule at the time an executive s employment is terminated for any reason will be forfeited without payment. If we terminate an executive for Cause (as defined below), or the executive voluntarily terminates his or her employment, all vested profits interest awards will also be forfeited at the time of the termination. If distributions are made with respect to a tier of these profits interest awards, both vested and unvested units will receive the distributions and the holder of such units would be entitled to keep any such distributions regardless of whether the units were subsequently forfeited. As a result of the consummation of our IPO, the following changes will be made to the terms of the profits interest awards:

- the profits interest awards will be an interest and an obligation of RSP Permian Holdco, L.L.C. and not of RSP Permian, L.L.C. or the issuer;

- if an executive s employment is terminated due to a death or Disability (as defined below), the executive (or his or her estate) may retain all vested profits interest awards as non-voting interests;

- the board of managers of RSP Permian Holdco, L.L.C. will have the ability, but not obligation, to waive the forfeiture of vested profits interest awards if an executive voluntarily terminates his or her employment; and

- the distribution thresholds for each tier of profits interest awards, and the distributions in which such awards will be entitled to a share of following the time the applicable distribution threshold has been met, will be based on all distributions to the members of equity interests in RSP Permian Holdco, L.L.C., not only on cash distributions as is the case while the awards are an obligation of RSP Permian, L.L.C., plus all cash distributions made to the members of equity interests in RSP Permian, L.L.C. prior to our IPO.

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The Tier I units will be entitled to 15% of future distributions to members only after all of the members that have made capital contributions to RSP Permian Holdco, L.L.C. shall have received cumulative distributions in respect of their membership interests equal to their cumulative capital contributions multiplied by 1.10n, where n is equal to a weighted average capital contribution factor determined as of the dates of the distributions. The Tier I A units will be entitled to 4% of future distributions to members only after all of the members that have made capital contributions to RSP Permian, L.L.C. (or RSP Permian Holdco, L.L.C.) shall have received cumulative distributions in respect of their membership interests equal to their cumulative capital contributions multiplied by 1.08n, where n is equal to a weighted average capital contribution factor determined as of the dates of the distributions. The Tier II units will be entitled to 5% of future distributions to members only after all of the members that have made capital contributions to RSP Permian Holdco, L.L.C. shall have received cumulative distributions in respect of their membership interests equal to two times their cumulative capital contributions. Tier III units will be entitled to 5% of future distributions to members only after all of the members that have made capital contributions to RSP Permian Holdco, L.L.C. shall have received cumulative distributions in respect of their membership interests equal to three times their cumulative capital contributions. The Tier IV units will be entitled to 5% of future distributions to members only after all of the members that have made capital contributions to RSP Permian Holdco, L.L.C. shall have received cumulative distributions in respect of their membership interests equal to four times their cumulative capital contributions. In connection with our IPO, distribution thresholds were not be modified as part of the transactions that were necessary to effect our IPO in the limited liability company agreement of RSP Permian Holdco, L.L.C., although references to members in the definition above shall refer to members of RSP Permian Holdco, L.L.C. rather than our members.

We expect that RSP Permian Holdco, L.L.C. s assets will continue to consist only of the shares of our common stock that it received as part of the IPO Transactions. Accordingly, the only events that would cause distributions to its members, including to the holders of the profits interest awards, would be either sales of shares of our common stock by RSP Permian Holdco, L.L.C. or in-kind distributions of such shares to its members.

A Fundamental Change is generally defined in the RSP Permian, L.L.C. limited liability company agreement as any of the following events: (i)(a) we merge or consolidate with or into an entity other than one of our subsidiaries; (b) our outstanding interests are sold or exchanged to any person other than one of our subsidiaries; or (c) we sell, lease license or exchange all or substantially all of our assets to a person that is not an affiliate, a member or a related party, and in each case the individuals that served as members of our board of directors immediately prior to the applicable transaction cease to constitute a majority of the members of the new board of directors; (ii) any person or group (other than us or any of our members) acquires the right to vote or dispose of our securities, unless the transaction was approved by our board; or (iii) our company is dissolved and liquidated. The definition of a Fundamental Change were not be modified in the limited liability company agreement of RSP Permian Holdco, L.L.C. following our IPO, although now references to us, our or we in the definition above now refer to RSP Permian Holdco, L.L.C.

As used in the paragraph above, a capital contribution to RSP Permian, L.L.C. generally means, for any member thereof, the dollar amount of any cash and the fair market value of any property contributed to RSP Permian, L.L.C. A capital contribution to RSP Permian Holdco, L.L.C. generally means, for any member thereof, the aggregate of (i) the dollar amount of any cash and the fair market value of any property contributed to the capital of RSP Permian, L.L.C. by the member prior to our IPO, and (ii) other than the interests in RSP Permian, L.L.C. that were contributed to RSP Permian, Inc. in connection with our corporate reorganization (as further described in Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation Recent Events Corporate Formation Transactions Corporate Reorganization), the dollar amount of any cash and the fair market value of any property contributed by the member to RSP Permian Holdco, L.L.C.

A termination for Cause will generally occur upon the individual s (i) conviction of, or plea of nolo contendere to, any felony or crime causing substantial harm to us or our affiliates or involving acts of theft, fraud, embezzlement, moral turpitude or similar conduct; (ii) repeated intoxication by alcohol or drugs during the performance of the individual s duties in a manner that materially and adversely affects the individual s performance of such duties; (iii) malfeasance in the conduct of the individual s duties; (iv) violation of any voting or transfer restriction agreement or a confidentiality and noncompete agreement that the individual has executed with us; and (v) failure to perform the duties of the individual s service relationship with us or our affiliates, or failure to follow or comply with the reasonable and lawful written directives of our board of managers or the board of an affiliate, as

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applicable. Upon the consummation of the our IPO, the termination for Cause was modified to generally occur upon the individual s (a) conviction of, or plea of nolo contendere to, any felony or to any crime or offense causing substantial harm to RSP Permian Holdco, L.L.C. or its affiliates or involving acts of theft, fraud, embezzlement, moral turpitude, or similar conduct, (b) repeated intoxication by alcohol or drugs during the performance of such holder s duties in a manner that materially and adversely affects the holder s performance of such duties, (c) malfeasance, in the conduct of such holder s duties, including, but not limited to, (1) misuse or diversion of funds of RSP Permian Holdco, L.L.C. or its affiliates, (2) embezzlement, or (3) material and intentional misrepresentations or concealments on any written reports submitted to RSP Permian Holdco, L.L.C. or its affiliates, (d) violation of any material provision of any voting and transfer restriction agreement or of a confidentiality and noncompete agreement that such person has executed with RSP Permian Holdco, L.L.C. or its affiliates, and such person has failed to cure such violation, if capable of being cured, within a reasonable period of time after such person has received notice of such violation, or (e) failure to perform the duties of such holder s employment or service relationship with RSP Permian Holdco, L.L.C. or its affiliates, or failure to follow or comply with the reasonable and lawful written directives of the board of managers of RSP Permian Holdco, L.L.C. or the managers or directors of an affiliate of RSP Permian Holdco, L.L.C. by which such holder is employed or in a service relationship, and such person has failed to cure such failure, if capable of being cured, within a reasonable period of time after such person has received notice of such failure.

A Disability will be defined in the limited liability company agreement of RSP Permian Holdco, L.L.C. as (i) the individual s inability to engage in any substantial gainful activity by reason of any medically determinable physical or mental impairment that can be expected to result in death or last for a continuous period of not less than 12 months; or (ii) the individual s receipt of income replacement benefits for a period of not less than three months under the accident and health plans maintained by RSP Permian Holdco, L.L.C. or its affiliates, by reason of the individual s medically determinable physical or mental impairment that can be expected to result in death or can be expected to last for a continuous period of not less than 12 months.

Because we are no longer a party to the RSP Permian Holdco, L.L.C. limited liability company agreement following our IPO, we cannot assure you that the terms of the profits interest units or the limited liability company agreement of RSP Permian Holdco, L.L.C. will not change in the future.

Employment, Severance or Change in Control Agreements

We historically have not maintained any employment, severance or change in control agreements with any of our named executive officers. In addition, none of the named executive officers are entitled to any payments or other benefits in connection with a termination of their employment or a change in control outside of the potential initial public offering bonuses described below.

2014 Long Term Incentive Plan

In connection with our IPO, we adopted the RSP Permian, Inc. 2014 Long Term Incentive Plan (the LTIP) for the employees, consultants and the directors of the Company and its affiliates who perform services for the Company. The purpose of the LTIP is to provide a means to attract and retain individuals to serve as our directors, employees and consultants who will provide services to us by affording such individuals a means to acquire and maintain ownership of awards, the value of which is tied to the performance of our common stock. The LTIP will provides for grants of: (i) incentive stock options qualified as such under U.S. federal income tax laws; (ii) stock options that do not qualify as incentive stock options; (iii) restricted stock awards (restricted stock awards); (iv) phantom stock awards; (v) restricted stock units; (vi) bonus stock; (vii) performance awards; and (viii) annual incentive awards (collectively referred to as awards).

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IPO Awards

In conjunction with our IPO, we granted each of our named executive officers time-based restricted stock awards on two dates in 2014: the first grant was made on February 11, 2014, and the second grant was made on February 25, 2014.

Pursuant to the first grant, Mr. Grimm received 19,512 shares of restricted stock that will vest in two equal installments occurring on February 11, 2015 and February 11, 2016. Pursuant to the second grant, Mr. Grimm received an additional 16,875 shares of restricted stock that will vest in three equal installments occurring on March 1, 2015, March 1, 2016 and March 1, 2017.

Pursuant to the first grant, Mr. Gray received 19,512 shares of restricted stock that will vest in two equal installments occurring on February 11, 2015 and February 11, 2016. Pursuant to the second grant, Mr. Gray received an additional 42,000 shares of restricted stock that will vest in three equal installments occurring on March 1, 2015, March 1, 2016 and March 1, 2017.

Pursuant to the first grant, Mr. McNeill received 81,301 shares of restricted stock that will vest in two equal installments occurring on February 11, 2015 and February 11, 2016. Pursuant to the second grant, Mr. McNeill received an additional 20,000 shares of restricted stock that will vest in three installments, with the first installment of 6,667 shares occurring on March 1, 2015, the second installment of 6,667 shares occurring on March 1, 2016 and the third installment of 6,666 shares occurring on March 1, 2017.

Pursuant to the first grant, Mr. Arrott received 19,512 shares of restricted stock that will vest in two installments, with the first installment of 14,634 shares occurring on February 11, 2015 and the second installment of 4,878 shares occurring on February 11, 2016. Pursuant to the second grant, Mr. Arrott received an additional 21,875 shares of restricted stock that will vest in three installments, with the first installment of 7,291 shares occurring on March 1, 2015, the second installment of 7,292 shares occurring on March 1, 2016 and the third installment of 7,292 shares occurring on March 1, 2017.

Pursuant to the first grant, Ms. Pollard received 17,073 shares of restricted stock that will vest in one installment on February 11, 2015. Pursuant to the second grant, Ms. Pollard received an additional 12,188 shares of restricted stock that will vest in three installments, with the first installment of 4,063 shares occurring on March 1, 2015, the second installment of 4,063 shares occurring on March 1, 2016 and the third installment of 4,062 shares occurring on March 1, 2017.

Pursuant to the first grant, Mr. Huck received 14,634 shares of restricted stock that will vest in one installment on February 11, 2015. Pursuant to the second grant, Mr. Huck received an additional 12,188 shares of restricted stock that will vest in three installments, with the first installment of 4,063 shares occurring on March 1, 2015, the second installment of 4,063 shares occurring on March 1, 2016 and the third installment of 4,062 shares occurring on March 1, 2017.

Compensation of Directors

We did not award any compensation to our non-employee individual directors during 2013. However, our board of directors believes that attracting and retaining qualified non-employee directors is critical to the future value growth and governance of our company. Our board of directors also believes that the compensation package for our non-employee directors should require a significant portion of the total compensation package to be equity-based to align the interest of these directors with our stockholders.

We intend to implement a non-employee compensation package whereby each non-employee director will be granted restricted stock and an annual cash compensation amount. Non-employee directors that serve in the Chairman role for each respective sub-committee will receive additional annual cash compensation.

Directors who are also our employees do not receive any additional compensation for their service on our board of directors.

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We expect that each director will be reimbursed for: (i) travel and miscellaneous expenses to attend meetings and activities of our board of directors or its committees; (ii) travel and miscellaneous expenses related to such director s participation in general education and orientation program for directors; and (iii) travel and miscellaneous expenses for each director s spouse who accompanies a director to attend meetings and activities of our board of directors or any of our committees.

Compensation Committee Interlocks and Insider Participation

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

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

Beneficial Ownership

The following table sets forth certain information regarding the beneficial ownership of our common stock as of March 31, 2014 by (i) each person who is known by the Company to own beneficially more than five percent of the outstanding shares of common stock, (ii) each named executive officer of the Company, (iii) each director of the Company and (iv) all directors and executive officers as a group. Unless otherwise noted, the mailing address of each person or entity named below is c/o RSP Permian, Inc., 3141 Hood Street, Suite 500, Dallas, Texas, 75219.

Name and Address	Number of Shares	Percentage of Class (1)
RSP Permian Holdco, L.L.C. (2)	16,285,481	22.5
Wallace Family Partnership, LP (3)	11,905,278	16.4
ACTOIL, LLC (4)	10,816,626	14.9
Michael Grimm	0	*
David Albin	0	*
Joseph B. Armes (5)	2,500	*
Ted Collins, Jr. (6)(7)	11,531,278	15.9
Steven Gray(8)	15,000	*
Scott McNeill (9)	10,000	*
Matthew S. Ramsey	5,000	*
Michael Wallace (3)(7)(10)	11,906,078	16.4
Zane Arrott	0	*
Tamara Pollard(11)	3,000	*
William Huck(7)	14,634	*
All Directors and Executive Officers as a Group (11 Persons)	23,487,490	32.4

* Less than 1%.

(1) The amounts and percentages of common stock beneficially owned are reported on the bases of regulations of the SEC governing the determination of beneficial ownership of securities. Under the rules of the SEC, a person is deemed to be a beneficial owner of a security if that person has or shares voting power, which includes the power to vote or direct the voting of such security, or investment power, which includes the power to dispose of or to direct the disposition of such security. Securities that can be so acquired are deemed to be outstanding for purposes of computing such person s ownership percentage, but not for purposes of computing any other person s percentage. Under these rules, more than one person may be deemed beneficial owner of the same securities, and a person may be deemed to be a beneficial owner of securities as to which such person has no economic interest. Except as otherwise indicated in these footnotes, each of the beneficial owners has, to our knowledge, sole voting and investment power with respect to the indicated shares of common stock, except to the extent this power may be shared with a spouse.

(2) The board of managers of RSP Permian Holdco, L.L.C. has voting and dispositive power over these shares. The board of managers of RSP Permian Holdco, L.L.C. consists of Michael Grimm, Steven D. Gray, Scott McNeill, Tony Weber, David R. Albin and Roy Aneed, none of whom individually have voting and dispositive power over these shares. Each such person expressly disclaims beneficial ownership over these

shares, except to the extent of any pecuniary interest therein. RSP Permian Holdco, L.L.C. is owned by Production Opportunities (an entity owned by Natural Gas Partners IX, L.P. and NGP IX Offshore Holdings, L.P. (collectively NGP IX)), certain members of our management team and certain of our employees. Certain members of our management team and certain of our employees also own incentive units in RSP Permian Holdco, L.L.C. Please see Item 11. Executive Compensation Outstanding Equity Awards at 2013 Fiscal Year-End for more information on the incentive units. NGP IX may be deemed to share voting and dispositive power over the reported shares and therefore may also be deemed to be the beneficial owner of these shares. NGP IX disclaims beneficial ownership of the reported shares in excess of its pecuniary interest in the shares. GFW IX, L.L.C. and G.F.W. Energy IX, L.P. may be deemed to share voting and dispositive power over the reported shares and therefore may also be deemed to be the beneficial owner of these shares by virtue of GFW IX, L.L.C. being the sole general partner of G.F.W. Energy IX, L.P. (which is the sole general partner of NGP IX). Kenneth A. Hersh, an Authorized Member of GFW IX, L.L.C., may also be deemed to share the power to vote, or to direct the vote, and to dispose, or to direct the disposition, of such shares. Mr. Hersh does not own directly any shares of our common stock. David Albin, one of our directors, may also be deemed to share the power to vote, or to direct the vote, and to dispose, or to direct the disposition of, those shares by virtue of his shared control of GFW IX, L.L.C. Mr. Albin does not own directly any shares of our common stock. GFW IX, L.L.C. has delegated full power and authority to manage NGP IX to NGP Energy Capital Management, L.L.C. and accordingly, NGP Energy Capital Management, L.L.C. may be deemed to share voting and dispositive power over these shares and therefore may also be deemed to be the beneficial owner of these shares.

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(3) Michael Wallace Management, LLC (Wallace Management) is the general partner of Wallace LP, and Mr. Wallace and Leslyn Wallace are the managers of Wallace Management. Accordingly, Mr. Wallace may be deemed to share voting and dispositive power over the 9,739,126 shares held by Wallace LP, and as a result may be deemed to beneficially own these shares. Mr. Wallace disclaims beneficial ownership of these shares except to the extent of his pecuniary interest therein.

(4) ACTOIL, LLC is a wholly owned subsidiary of TIAA Oil and Gas Investments, LLC, its sole member. TIAA Oil and Gas Investments, LLC is a wholly owned subsidiary of Teachers Insurance and Annuity Association of America, its sole member. Because of the foregoing relationships, each of ACTOIL, LLC, TIAA Oil and Gas Investments, LLC and Teachers Insurance and Annuity Association of America may be deemed to have voting and dispositive power over the reported shares and may also be deemed to be the beneficial owner of these shares. Each of ACTOIL, LLC, TIAA Oil and Gas Investments, LLC and Teachers Insurance and Annuity Association of America disclaim beneficial ownership of the reported shares in excess of its pecuniary interest in the shares.

(5) These shares are held by a family limited partnership. Mr. Armes owns 50% of the general partner of the family limited partnership. Mr. Armes disclaims beneficial ownership of these shares except to the extent of his pecuniary interest therein.

(6) 1,000 shares are held by Mr. Collins spouse. Mr. Collins disclaims beneficial ownership of these shares except to the extent of his pecuniary interest therein.

(7) 2,166,152 shares are held of record by Collins & Wallace Holdings, LLC. Mr. Collins and Wallace LP are the members of Collins & Wallace Holdings, LLC. Wallace Management is the general partner of Wallace LP, and Mr. Wallace and Mrs. Wallace are the managers of Wallace Management. Accordingly, Messrs. Collins and Wallace may be deemed to share voting and dispositive power over the 2,166,152 shares held of record by Collins & Wallace Holdings, LLC, and as a result may be deemed to beneficially own these shares. Messrs. Collins and Wallace each disclaim beneficial ownership of these shares except to the extent of their respective pecuniary interest therein.

(8) Each of Messrs. Gray and Huck own one-third of the outstanding limited partnership interests of Pecos, directly and through their membership interest in Pecos Operating Company, LLC, the general partner of Pecos (Pecos GP), and serve as managers of Pecos GP. Pecos GP is manager-managed and actions require a majority of the three managers to take any actions, including with respect to all investment and dispositive decisions for the shares of the Company s common stock held by Pecos. As a result, none of Messrs. Gray and Huck individually have voting or dispositive power over these shares. Pecos GP has voting and dispositive power over such shares. Pecos owns 105,170 shares.

(9) 900 shares are held by Mr. McNeill as custodian for minor children under the Uniform Transfer to Minors Act. Mr. McNeill disclaims beneficial ownership of these shares.

(10) 500 shares are held by Mr. Wallace as custodian for a minor child under the Uniform Transfer to Minors Act. Mr. Wallace disclaims beneficial ownership of these shares. 300 shares are held by a member of Mr. Wallace s immediate family sharing the same household. Mr. Wallace disclaims beneficial ownership of these shares.

(11) 3,000 shares are held by Ms. Pollard s spouse. Ms. Pollard disclaims beneficial ownership of these shares.

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

Procedures for Review, Approval and Ratification of Related Person Transactions

Prior to the closing of our IPO, we did not maintain a policy for approval of Related Party Transactions. A Related Party Transaction is a transaction, arrangement or relationship in which we or any of our subsidiaries was, is or will be a participant, the amount of which involved exceeds $120,000, and in which any Related Person had, has or will have a direct or indirect material interest. A Related Person means:

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

Our board of directors periodically reviews all Related Party Transactions that the rules of the SEC require be disclosed in the Company s annual report or proxy statement, as applicable, and makes a determination regarding the initial authorization or ratification of any such transaction.

In determining whether to approve or disapprove entry into a Related Party Transaction, our board of directors takes into account, among other factors, the following: (1) whether the Related Party Transaction is on terms no less favorable than terms generally available to an unaffiliated third-party under the same or similar circumstances and (2) the extent of the Related Person s interest in the transaction.

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Since January 1, 2013, there has not been any transaction or series of similar transactions to which the Company was or is a party in which the amount involved exceeded or exceeds $120,000 and in which any of the Company s directors, executive officers, holders of more than 5% of any class of its voting securities, or any member of the immediate family of any of the foregoing persons, had or will have a direct or indirect material interest, other than compensation arrangements with directors and executive officers, which are described in Item 11. Executive Compensation, and the transactions described or referred to below.

Historical Transactions with Affiliates

Resolute Disposition

We sold all of our working interests in certain Permian Basin assets to Resolute for $214 million in a transaction that closed in part in December 2012 and in part in March 2013. An affiliate of NGP, Natural Gas Partners VII, L.P. (NGP VII), and an affiliated co-investment fund (NGP VII Co-Invest) collectively own less than 5% of the total issued and outstanding shares of the publicly-traded holding company of Resolute, Resolute Energy Corporation (Resolute Parent). Assuming full exercise of all warrants held by an entity owned by NGP VII and NGP VII Co-Invest, however, NGP VII and NGP VII Co-Invest would collectively own 10.7% of Resolute Parent. NGP is also entitled to designate one member of Resolute Parent s board of directors.

Rising Star Acquisition

We acquired from Rising Star working interests in certain acreage and wells in the Permian Basin in exchange for shares of RSP Permian, Inc. s common stock and the right to receive approximately $1.7 million in cash. Prior to our IPO, an affiliate of NGP, Natural Gas Partners VIII, L.P., owns over 90% of the membership interests in the general partner of Rising Star and over 80% of the membership interests of the sole owner of Rising Star, Rising Star Energy Holdings, L.P. Certain members of our management team, Michael Grimm, Zane Arrott and Tamara Pollard, are officers of Rising Star. Mr. Grimm, Mr. Arrott, Ms. Pollard and Ted Collins, Jr. own 3%, 3%, 2% and 4% of the membership interest in Rising Star Energy Holdings, L.P. Immediately prior to the completion of our IPO, Rising Star owned approximately 3% of RSP Permian, Inc. s common stock.

Corporate Reorganization

In connection with our IPO, (i) the members of RSP Permian, L.L.C. contributed all of their interests in RSP Permian, L.L.C. to RSP Permian Holdco, L.L.C., a newly-formed entity that was wholly owned by such members, and (ii) RSP Permian Holdco, L.L.C. contributed all of its interests in RSP Permian, L.L.C. to RSP Permian, Inc. in exchange for shares of common stock of RSP Permian, Inc., an assignment of RSP Permian, L.L.C. s pro rata share of an escrow related to the Resolute Disposition (which escrow is described in Note 3 of the historical combined financial statements of RSP Permian, L.L.C. and Rising Star) and the right to receive approximately $27.7 million in cash. RSP Permian Holdco, L.L.C. is owned by Production Opportunities, an entity affiliated with NGP, certain members of our management team and certain of our employees.

The Collins and Wallace Contributions

Mr. Collins, Wallace LP and Collins & Wallace Holdings, LLC each contributed to us working interests in certain of RSP Permian, L.L.C. s existing properties. In exchange, (i) Collins received shares of RSP Permian, Inc. s common stock and the right to receive approximately $1.6 million in cash, (ii) Wallace LP received 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 shares of RSP Permian, Inc. s common stock. See Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operation Recent Events Corporate Formation Transactions The Collins and Wallace Contributions for more information regarding the Collins and Wallace Contributions. Wallace LP is a family-owned entity owned by Michael W. Wallace and certain members of Mr. Wallace s family. The general partner of Wallace LP is Michael Wallace Management, LLC, which is controlled by Mr. Wallace. Collins & Wallace Holdings, LLC is owned equally by Mr. Collins and Wallace LP. Mr. Collins is the manager of Collins & Wallace Holdings, LLC.

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Messrs. Collins and Wallace own approximately 15.9% and 16.4% of RSP Permian, Inc. s common stock, respectively,

Pecos Contribution

We acquired from Pecos working interests in certain acreage and wells in the Permian Basin in exchange for shares of RSP Permian, Inc. s common stock. Steven Gray, Erik B. Daugbjerg and William Huck, each a member of our management team, each owns one-third of the outstanding partnership interests of Pecos, directly and through their membership interests in Pecos Operating Company, LLC, the general partner of Pecos. In addition, each of Messrs. Gray, Daugbjerg and Huck serve as managers of the general partner of Pecos.

Coronado Midstream, LLC

We are party to a gas purchase agreement, dated March 1, 2009, as amended, with MidMar (which was renamed Coronado Midstream, LLC in September 2013), an entity that owns a natural gas gathering system and processing plant in the Permian Basin. Under this agreement, Coronado Midstream, LLC is obligated to purchase from us, and we are obligated to sell to Coronado Midstream, LLC, all of the natural gas conforming to certain quality specifications produced from certain of our Permian Basin acreage.

Messrs. Collins and Wallace own approximately 10.3% and 10.3% of the ownership interests in Coronado Midstream, LLC, and the remaining interests in Coronado Midstream, LLC are owned by unaffiliated third parties. Mr. Collins is the chairman of the board of managers of Coronado Midstream, LLC. For the years ended December 31, 2011, 2012 and 2013, Coronado Midstream, LLC accounted for 9%, 11% and 8% of our revenue, respectively.

Operating Overhead Reimbursements

In connection with the operation of certain oil and natural gas properties, pursuant to joint operating agreements, the Company charges Mr. Collins and Wallace LP for administrative overhead (commonly referred to as the Council of Petroleum Accountants Society (COPAS) fees). Such overhead recoveries from Mr. Collins and Wallace LP each totaled $0.3 million during the year ended December 31, 2012. Wallace LP is a family-owned entity owned by Mr. Wallace and certain members of Mr. Wallace s family. The general partner of Wallace LP is Michael Wallace Management, LLC, which is controlled by Mr. Wallace.

Reimbursement of Offering Expenses

Approximately $1.5 million of the estimated $3.5 million of expenses of our IPO payable by us have been borne by the members of RSP Permian Holdco, L.L.C. as a result of the IPO Transactions. We have agreed to reimburse RSP Permian Holdco, L.L.C. for such expenses.

Registration Rights Agreement

In connection with the closing of our IPO, we entered into a registration rights agreement with RSP Permian Holdco, L.L.C., Mr. Collins, Wallace LP, ACTOIL, Rising Star and Pecos. Pursuant to the registration rights agreement, we have agreed to register the sale of shares of our common stock under certain circumstances.

Demand Rights. At any time after the 180 day lock-up period and subject to the limitations set forth below, each of RSP Permian Holdco, L.L.C., Ted Collins, Jr., Wallace LP and ACTOIL (or their permitted transferees) has the right to require us by written notice to prepare and file a registration statement registering the offer and sale of a certain number of their shares of common stock. Generally, we are required to provide notice of the request within five business days following the receipt of such demand request to all other holders of our common stock, who may, in certain circumstances, participate in the registration. Subject to certain exceptions, we will not be obligated to effect a demand registration within 90 days after the closing of any underwritten offering of shares of our common stock. Further, we are not obligated to effect:

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- (i) through December 31, 2016, more than a total of three demand registrations or (ii) on or after January 1, 2017, more than a total of one demand registration per calendar year at the request of RSP Permian Holdco, L.L.C.;
- more than two demand registrations for Collins;
- more than two demand registrations for Wallace LP; and
- more than two demand registrations for ACTOIL.

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

In addition, each of RSP Permian Holdco, L.L.C., Mr. Collins, Wallace LP and ACTOIL (or their permitted transferees) has the right to require us, subject to certain limitations, to effect a distribution of any or all of their shares of common stock by means of an underwritten offering. In general, any demand for an underwritten offering (other than the first requested underwritten offering made in respect of a prior demand registration and other than a requested underwritten offering made concurrently with a demand registration) shall constitute a demand request subject to the limitations set forth above.

Piggyback Rights. Subject to certain exceptions, if at any time we propose to register an offering of common stock or conduct an underwritten offering, whether or not for our own account, then we must notify RSP Permian Holdco, L.L.C., Mr. Collins, Wallace LP, ACTOIL, Rising Star and Pecos (or their permitted transferees) of such proposal at least five business days before the anticipated filing date or commencement of the underwritten offering, as applicable, to allow them to include a specified number of their shares in that registration statement or underwritten offering, as applicable.

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

Stockholders Agreement

In connection with the closing of our IPO, we entered into a stockholders agreement with RSP Permian Holdco, L.L.C., Mr. Collins, Wallace LP, Rising Star and Pecos. The stockholders agreement provide each of RSP Permian Holdco, L.L.C., Mr. Collins and Wallace LP with the right to designate a certain number of nominees to our board of directors, subject to the following:

- RSP Permian Holdco, L.L.C. has the right to designate two nominees to our board of directors, provided that such number of nominees shall be reduced to one and zero if RSP Permian Holdco, L.L.C. and its affiliates collectively own less than 15% and 5%, respectively, of the outstanding shares of our common stock;

- Mr. Collins has the right to designate one nominee to our board of directors, provided that such number of nominees shall be reduced to zero if Mr. Collins and his affiliates collectively own less than 5% of the outstanding shares of our common stock, and provided further that Mr. Collins and his affiliates shall be deemed to beneficially own only the number of shares that is proportional to their ownership of Collins & Wallace Holdings, LLC; and

- Wallace LP has the right to designate one nominee to our board of directors, provided that such number of nominees shall be reduced to zero if Wallace LP and its affiliates collectively own less than 5% of the outstanding shares of our common stock, and provided further that Wallace LP and its affiliates shall be

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deemed to beneficially own only the number of shares that is proportional to their ownership of Collins & Wallace Holdings, LLC.

The stockholders agreement also requires the stockholders party thereto to take all necessary actions, including voting their shares of our common stock, to cause the election of the nominees designated by RSP Permian Holdco, L.L.C., Mr. Collins and Wallace LP.

In addition, the stockholders agreement provides that for so long as RSP Permian Holdco, L.L.C. has the right to designate two directors to our board of directors, we will cause any committee of our board of directors to include in its membership at least one director designated by RSP Permian Holdco, L.L.C., except to the extent that such membership would violate applicable securities laws or stock exchange rules. Further, the stockholders agreement provides RSP Permian Holdco, L.L.C. the right to designate a non-voting representative to attend meetings of our board of directors and committees thereof for so long as RSP Permian Holdco, L.L.C. beneficially owns more than a certain percentage of the outstanding shares of our common stock and has designated a nominee to our board of directors that is not a manager, employee, director or officer of Production Opportunities or Natural Gas Partners IX, L.P. or any affiliate thereof.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The table below sets forth the aggregate fees billed by Grant Thornton LLP, the Company s independent registered public accounting firm, for the last two fiscal years (in thousands):

	2013	2012
Audit Fees(1)	$ 593,208	$ 133,900
Audit-Related Fees		
Tax Fees		
All Other Fees		
Total	$ 593,208	$ 133,900

(1) Audit fees represent fees for professional services provided in connection with (a) review of the Company s quarterly consolidated financial statements and (b) review of the Company s filings with the SEC, including review and preparation of registration statements, comfort letters, consents and research necessary to comply with generally accepted auditing standards for the year ended December 31, 2013.

For the years ended December 31, 2013 and 2012, we did not have an audit committee or pre-approval policy. The charter of the audit committee, which was adopted in connection with our IPO, requires that the audit committee review and pre-approve the plan and scope of Grant Thornton LLP s audit, audit-related, tax and other services.

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PART IV

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

a. The following documents are filed as a part of this Report on Form 10-K or incorporated herein by reference:

(1) Financial Statements:

See Item 8. Financial Statements and Supplementary Data.

(2) Financial Statement Schedules:

None.

(3) Exhibits:

The following documents are included as exhibits to this report:

Exhibit 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 10, 2014).
4.2	Registration Rights Agreement, dated as of January 23, 2014, among RSP Permian, Inc., 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. 001-36273) filed with the Commission on January 29, 2014).
4.3	Stockholders Agreement, dated as of January 23, 2014, among RSP Permian, Inc., 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. 001-36273) filed with the Commission on January 29, 2014).

10.1	Credit Agreement, dated September, 10, 2013, by and between 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. 377-00338) filed with the Commission on October 8, 2013).
10.2	Amended and Restated Liability Company Agreement of RSP Permian Holdco, L.L.C., dated January 23, 2014 (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 29, 2014).
10.3	Indemnification Agreement (incorporated by reference to Exhibit 10.4 to the Company s Registration Statement on Form S-1 (File No. 333-192268) filed with the Commission on January 2, 2014).
10.4	RSP Permian, Inc. 2014 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K (File No. 001-36264) filed with the Commission on January 16, 2014).
21.1(a)	List of Subsidiaries of RSP Permian, Inc.
23.1(a)	Consent of Grant Thornton LLP.
23.2(a)	Consent of Grant Thornton LLP.
23.3(a)	Consent of Ryder Scott Company, L.P.

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Exhibit No.	**Description**
23.4(a)	Consent of Ryder Scott Company, L.P.
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 Section 906 of the Sarbanes-Oxley Act of 2002 by Chief Executive Officer.
32.2(b)	Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 by Chief Financial Officer.
99.1(a)	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2013.
99.2(a)	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2013.

(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 this Report for purposes of Section 18 of the Securities Exchange Act, as amended, or otherwise subject to the liability of Section 18 of the Securities Exchange Act, as amended, and this certification will not be deemed to be incorporated by reference into any filing under the Securities Exchange Act of 1933, as amended, except to the extent that the registrant specifically incorporates it by reference.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this Report on Form 10-K 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 31, 2014

Pursuant to the requirements of the Securities Exchange Act of 1934, this Report on Form 10-K 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 31, 2014
/s/ Scott McNeill Scott McNeill	Chief Financial Officer and Director (Principal Financial Officer) (Principal Accounting Officer)	March 31, 2014
/s/ David Albin David Albin	Director	March 31, 2014
/s/ Joseph B. Armes Joseph B. Armes	Director	March 31, 2014
/s/ Ted Collins, Jr. Ted Collins, Jr.	Director	March 31, 2014
/s/ Matthew S. Ramsey Matthew S. Ramsey	Director	March 31, 2014
/s/ Michael W. Wallace Michael W. Wallace	Director	March 31, 2014

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INDEX TO FINANCIAL STATEMENTS

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholder

RSP Permian, Inc.

We have audited the accompanying balance sheet of RSP Permian, Inc. (a Delaware corporation) (the Company) as of December 31, 2013. This financial statement is the responsibility of the Company s management. Our responsibility is to express an opinion on this financial statement based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the balance sheet is free of material misstatement. We were not engaged to perform an audit of the Company s internal control over financial reporting. Our audit 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 statement, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

In our opinion, the balance sheet referred to above presents fairly, in all material respects, the financial position of RSP Permian, Inc. as of December 31, 2013 in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Dallas, Texas

March 31, 2014

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RSP PERMIAN, INC.

BALANCE SHEET

		December 31, 2013
Assets		
Receivable from stockholder	$	10
Total assets	$	10
Stockholder s equity		
Common stock, $0.01 par value; authorized 1,000,000 shares; 1,000 issued and outstanding	$	10
Total stockholder s equity	$	10

See the accompanying notes to the balance sheet.

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RSP PERMIAN, INC.

NOTES TO BALANCE SHEET

1. Nature of Operations

RSP Permian, Inc. (the Company) was formed on September 30, 2013, pursuant to the laws of the State of Delaware to become a holding company for RSP Permian, L.L.C.

2. Summary of Significant Accounting Policies

Basis of Presentation

This balance sheet has been prepared in accordance with accounting principles generally accepted in the United States of America. Separate statements of operations, statements of changes in stockholder s equity and statements of cash flows have not been presented because the Company has had no business transactions or activities to date.

3. Subsequent Events

On January 23, 2014, the Company completed the initial public offering of common stock to the public (the Offering). Shares of common stock of RSP Inc. began trading on the New York Stock Exchange under the ticker RSPP on January 17, 2014. Concurrent with the completion of the Offering, all interests in RSP Permian, L.L.C. (RSP) and certain assets of Rising Star Energy Development Co., L.L.C. (Rising Star) were contributed to the Company. The Company sold 23 million shares at $19.50 per share, raising $449 million of gross proceeds. Of the 23 million shares issued to the public, 9.2 million were primary shares issued by the Company resulting in $166 million of net proceeds, which were used to retire RSP s $70 million term loan, repay RSP s revolving credit facility balance of $56 million in its entirety, pay cash as partial consideration for certain working interest in oil and gas properties contributed to the Company in conjunction with the Offering (described below), and for other general corporate purposes. The remaining 13.8 million shares sold in the Offering were sold by selling stockholders and the Company did not receive any proceeds from the sale of those shares.

In connection with the Offering, several transactions occurred simultaneously which changed the structure and scope of the Company and RSP.

- Corporate Reorganization:

- RSP, which is our accounting predecessor, was contributed to RSP Permian Holdco L.L.C., a newly formed limited liability company which simultaneously contributed all of its interests in RSP to the Company in exchange for shares of the Company s common stock and cash. As a result, RSP became a wholly owned subsidiary of the Company.

- The Rising Star Acquisition:

- RSP acquired from Rising Star certain acreage and wells in the Permian Basin in which RSP already had working interests in for shares of the Company s common stock and cash.

- The Collins and Wallace Contributions:

- Ted Collins, Jr. (Collins), Wallace Family Partnership, LP (Wallace LP) and a newly formed entity, Collins & Wallace Holdings, LLC, that is jointly owned by Collins and Wallace LP contributed to RSP certain working interests. In exchange, Collins and Wallace LP received both cash and shares of the Company s common stock and Collins & Wallace Holdings, LLC received only shares of the Company s common stock. The Company is in the process of evaluating the fair values of the contributed assets in order to determine the appropriate purchase price allocation.

- The Pecos Contribution:

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

- The ACTOIL NPI Repurchase:

- ACTOIL, the owner of a 25% net profits interest issued by RSP, contributed to RSP its 25% net profits interest in exchange for shares of the Company s common stock. The Company is in the process of evaluating the fair values of the contributed assets in order to determine the appropriate purchase price allocation.

Subsequent to year-end, RSP, our wholly-owned subsidiary and accounting predecessor, has closed approximately $79 million of acquisitions. On February 28, 2014, RSP closed the acquisition of a 17.5% non-operated working interest in producing properties located in Martin County, Texas. The properties are contiguous to RSP operated leasehold positions in Martin County. In addition, RSP added additional undeveloped leasehold in Glasscock County and Dawson County during the first quarter of 2014.

The Company has evaluated subsequent events through the date that these financial statements were available to be issued. Except as described above, the Company determined there were no additional events that required disclosure or recognition in these financial statements.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Managers

RSP Permian, L.L.C. and

Rising Star Energy Development Co., L.L.C.

We have audited the accompanying combined balance sheets of RSP Permian, L.L.C. and Rising Star Energy Development Co., L.L.C. (collectively, the Predecessor) as of December 31, 2013 and 2012, and the related combined statements of operations, changes in members equity, and cash flows for each of the three years in the period ended December 31, 2013. These financial statements are the responsibility of the Predecessor 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 Predecessor 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 Predecessor 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 combined financial statements referred to above present fairly, in all material respects, the financial position of RSP Permian, L.L.C. and Rising Star Energy Development Co., L.L.C. as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP

Dallas, Texas

March 31, 2014

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**RSP PERMIAN, L.L.C. AND RISING STAR ENERGY DEVELOPMENT CO., L.L.C.
(PREDECESSOR)**

COMBINED BALANCE SHEETS

	Pro Forma December 31, 2013 (Unaudited)	December 31, 2013	2012
		(In thousands)	
ASSETS			
CURRENT ASSETS			
Cash and cash equivalents	$ 13,234	$ 13,234	$ 51,232
Restricted short-term investment			1,031
Accounts receivable	26,346	26,346	21,614
Accounts receivable, related party	3,672	3,672	4,232
Escrow receivable	3,197	3,197	3,135
Escrow deposit	15	15	
Derivative instruments	671	671	1,112
Total current assets	47,135	47,135	82,356
PROPERTY, PLANT AND EQUIPMENT			
Oil and natural gas properties, successful efforts method	595,486	595,486	476,816
Accumulated depletion	(88,514)	(88,514)	(60,489)
Total oil and natural gas properties, net	506,972	506,972	416,327
Other property and equipment, net	9,316	9,316	5,085
Total property, plant and equipment	516,288	516,288	421,412
LONG-TERM ASSETS			
Derivative instruments	1,078	1,078	2,325
Restricted cash	150	150	150
Other assets	23,004	23,004	6,995
Total long-term assets	24,232	24,232	9,470
TOTAL ASSETS	$ 587,655	$ 587,655	$ 513,238
LIABILITIES AND MEMBERS EQUITY			
CURRENT LIABILITIES			
Accounts payable	$ 18,548	$ 18,548	$ 23,437
Accrued expenses	10,460	10,460	3,249
Distribution payable	29,484		
Interest payable	296	296	252
Derivative instruments	1,562	1,562	1,227
Total current liabilities	60,350	30,866	28,165
LONG-TERM LIABILITIES			
Asset retirement obligations	2,584	2,584	2,716
Derivative instruments	43	43	345
Term loan	70,000	70,000	
Revolving credit facility	58,155	58,155	111,586
NPI payable	36,931	36,931	16,583
Deferred taxes	2,195	2,195	
Total long-term liabilities	169,908	169,908	131,230
Total liabilities	230,258	200,774	159,395
MEMBERS EQUITY	357,397	386,881	353,843
TOTAL LIABILITIES AND MEMBERS EQUITY	$ 587,655	$ 587,655	$ 513,238

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

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RSP PERMIAN, L.L.C. AND RISING STAR ENERGY DEVELOPMENT CO., L.L.C.
(PREDECESSOR)

COMBINED STATEMENTS OF OPERATIONS

	For the year ended December 31, 2013	2012	2011
	(In thousands, except per share data)		
REVENUES			
Oil sales	$ 110,345	$ 91,441	$ 56,772
Natural gas sales	5,383	4,284	7,217
NGL sales	7,314	8,702	
Total revenues	123,042	104,427	63,989
OPERATING EXPENSES			
Lease operating expenses	$ 14,664	$ 12,854	$ 5,712
Production and ad valorem taxes	8,326	7,575	4,192
Depreciation, depletion and amortization	47,158	48,803	16,612
Asset retirement obligation accretion	121	115	46
Impairments			2,241
General and administrative expenses	3,852	2,859	3,509
Total operating expenses	74,121	72,206	32,312
(Gain) on sale of assets	(22,700)	(6,734)	(105,333)
OPERATING INCOME	$ 71,621	$ 38,955	$ 137,010
OTHER INCOME (EXPENSE)			
Other income	$ 1,202	$ 884	$ 163
Loss on derivative instruments	(2,607)	(796)	(1,979)
Interest expense	(5,216)	(3,474)	(3,472)
Total other expense	(6,621)	(3,386)	(5,288)
INCOME BEFORE TAXES	65,000	35,569	131,722
INCOME TAX (EXPENSE) BENEFIT	(2,262)	339	(550)
NET INCOME	$ 62,738	$ 35,908	$ 131,172
PRO FORMA INFORMATION (UNAUDITED):			
Net income	$ 62,738		
Pro forma provision for income taxes	(22,586)		
Pro forma net income	$ 40,152		
Pro forma income per common share			
Basic and diluted	$ 1.26		
Weighted average pro forma shares outstanding			
Basic and diluted	31,934		

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

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RSP PERMIAN, L.L.C. AND RISING STAR ENERGY DEVELOPMENT CO., L.L.C.
(PREDECESSOR)

COMBINED STATEMENT OF CHANGES IN MEMBERS EQUITY

	RSP	Rising Star (In thousands)	Total Members Equity
BALANCE AT JANUARY 1, 2011	$ 178,104	$ 8,659	$ 186,763
Net income	122,400	8,772	131,172
BALANCE AT DECEMBER 31, 2011	300,504	17,431	317,935
Net income	34,461	1,447	35,908
BALANCE AT DECEMBER 31, 2012	334,965	18,878	353,843
Contributions	300		300
Distributions	(30,000)		(30,000)
Net income	60,469	2,269	62,738
BALANCE AT DECEMBER 31, 2013	$ 365,734	$ 21,147	$ 386,881

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

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RSP PERMIAN, L.L.C. AND RISING STAR ENERGY DEVELOPMENT CO., L.L.C.
(PREDECESSOR)

COMBINED STATEMENTS OF CASH FLOWS

	For the year ended December 31,		
	2013	2012	2011
		(In thousands)	
CASH FLOWS FROM OPERATING ACTIVITIES			
Net income	$ 62,738	$ 35,908	$ 131,172
Adjustments to reconcile net income to net cash provided by operating activities:			
Depletion and depreciation	47,158	48,347	16,246
Deferred taxes	2,195		
Abandoned equipment and intangibles	2	135	131
Impairment			2,241
Accretion of asset retirement obligations	121	115	46
Bad debt expense			65
Amortization of loan fees	1,746	456	366
Equity in earnings of investment	(14)	(11)	(55)
Gain on certificate of deposit		(3)	(3)
(Gain) on sale of assets	(22,700)	(6,734)	(105,333)
Loss on derivative instruments	2,607	796	1,979
Net cash payments on settled derivatives	(886)	(474)	(856)
Changes in operating assets and liabilities:			
Accounts receivable and accounts receivable from related parties	(3,758)	(3,907)	(22,719)
Other assets	(17,739)	(2,148)	(624)
Interest payable	44	63	23
Accounts payable	(5,380)	(1,722)	2,298
Accrued expenses	7,211	1,982	1,266
Net cash provided by operating activities	$ 73,345	$ 72,803	$ 26,243
CASH FLOWS FROM INVESTING ACTIVITIES			
Payment of premium for put options	$	$	$ (2,588)
Restricted cash			(150)
Proceeds from sale of assets	115,339	63,196	182,640
Increase in equity investment		(1,146)	
Additions to other property and equipment	(3,265)	(1,287)	(402)
Additions to oil and natural gas properties	(231,665)	(173,983)	(95,654)
Net cash provided by (used in) investing activities	$ (119,591)	$ (113,220)	$ 83,846
CASH FLOWS FROM FINANCING ACTIVITIES			
Payment of debt issuance costs	$	$	$ (241)
Capital contributions	300		
Distributions	(30,000)		
Borrowings under long-term debt	101,569	90,000	55,086
Restricted short term investment	1,031		
Payments on long-term debt	(85,000)	(25,000)	(160,000)
NPI payable	20,348	16,583	
Net cash provided by (used in) financing activities	$ 8,248	$ 81,583	$ (105,155)
NET CHANGE IN CASH	$ (37,998)	$ 41,166	$ 4,934
CASH AT BEGINNING OF YEAR	$ 51,232	$ 10,066	$ 5,132
CASH AT END OF YEAR	$ 13,234	$ 51,232	$ 10,066
SUPPLEMENTAL CASH FLOW INFORMATION			

Cash paid for interest	$	3,373	$	3,420	$	3,293
NON-CASH INVESTING ACTIVITIES						
Assets purchased included in accounts payable and accrued expenses	$	16,901	$	21,416	$	20,099
Asset retirement obligation acquired	$	296	$		$	694

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

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RSP PERMIAN, L.L.C. AND RISING STAR ENERGY DEVELOPMENT CO., L.L.C.
(PREDECESSOR)

NOTES TO COMBINED FINANCIAL STATEMENTS

NOTE 1 NATURE OF OPERATIONS AND BASIS OF PRESENTATION

RSP Permian, L.L.C., a Delaware limited liability company (RSP), was formed on October 18, 2010 by its management team and an affiliate of Natural Gas Partners, a family of energy-focused private equity investment funds (NGP). RSP is engaged in the acquisition, development and operation of oil and natural gas properties. On December 15, 2010, primary operations commenced through a significant acquisition of oil and natural gas leases and corresponding interests on acreage located in the Permian Basin in and around Midland, Texas. Over 90% of RSP s outstanding equity is indirectly owned by Natural Gas Partners IX, L.P. and NGP IX Offshore Holdings, L.P. (collectively, NGP IX).

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). Natural Gas Partners VIII, L.P. (NGP VIII) 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.

All power and authority to control the core functions of RSP and Rising Star (collectively, the Predecessor) are controlled by NGP VIII and NGP IX, respectively. Through the delegation of authority of the general partners of NGP VIII and NGP IX to NGP Energy Capital Management, L.L.C. (NGP ECM), all power and authority of the respective fund limited partnership in effectuating its core investment, management and divestment function is controlled by NGP ECM. The results of RSP and Rising Star have been combined for all periods presented.

The accompanying financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America (U.S. GAAP).

NOTE 2 SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Use of Estimates

The preparation of the combined 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 which may affect the amount at which oil and natural gas properties are recorded. Estimation of asset retirement obligations (AROs), valuation of derivative instruments and the fair value of incentive unit compensation also require significant assumptions. It is possible 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. Certain reclassifications of amounts from lease operating expenses to production and ad valorem expenses have been made to prior periods to conform to the current year presentation.

Reclassifications

Certain reclassifications of amounts from lease operating expenses to production and ad valorem expenses have been made to prior periods to conform to current year presentation.

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Cash and Cash Equivalents

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

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

The Predecessor 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 combined statement of operations in the period of change. Gains and losses on derivatives are included in cash flows from operating activities. Premiums paid for put options are included in cash flows from investing activities.

Accounts Receivable

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 Predecessor believes it will receive. The Predecessor routinely reviews outstanding balances, assesses the financial strength of its customers and records a reserve for amounts not expected to be fully recovered. The Predecessor has not provided an allowance for doubtful accounts based on management s expectations that all receivables at year-end will be fully 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, 2013, 2012 or 2011.

Transactions with Related Parties

Wallace Family Partnership, LP (Wallace LP) has a non-operated working interest in substantially all the oil and natural gas assets the Predecessor operates. Leslyn Wallace is a limited partner of Wallace LP and an employee of RSP. The carrying amount of the receivable from Wallace LP was approximately $3.7 million and $4.2 million at December 31, 2013 and 2012. The Predecessor considers the accounts receivable from Wallace LP to be fully collectible.

Oil and Natural Gas Properties

The Predecessor uses the successful efforts method of accounting for its oil and natural gas exploration and production activities. Costs incurred by the Predecessor 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 Predecessor 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 Predecessor did not capitalize any interest in 2013 and 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 charged to expense as incurred. Gains and losses arising from sales of properties are generally included as income. Unproved properties are assessed periodically for possible impairment.

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Capitalized acquisition costs attributable to proved oil and natural gas properties 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 $46.9 million, $48.0 million and $16.0 million for the years ended December 31, 2013, 2012 and 2011, respectively, and is included in depreciation, depletion and amortization in the accompanying combined statements of operations.

The Predecessor s oil and natural gas properties as of December 31, 2013 and 2012 consisted of the following:

	December 31, 2013	December 31, 2012
	(In thousands)	
Proved oil and natural gas properties	$ 562,019	$ 447,369
Unproved oil and natural gas properties	33,467	29,447
Less: accumulated depletion	(88,514)	(60,489)
	$ 506,972	$ 416,327

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, 2013 and 2012, 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 depletable unit (field) is impaired, the Predecessor compares the carrying value of the depletable unit 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 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 periodically to determine whether they have been impaired. An impairment allowance is provided on an unproved property when the Predecessor 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. In 2011, the Predecessor recognized impairment losses of $2.2 million related to oil and natural gas properties, which were written down to fair value using Level 3 fair-value inputs. No impairment of proved property was recorded for the years ended December 31, 2013 and 2012.

Natural gas volumes are converted to barrels of oil equivalent (Boe) at the rate of six thousand cubic feet (Mcf) of natural gas to one barrel (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.

Other Property and Equipment

Other capital assets include 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, 2013, 2012 and 2011 was $0.3 million, $0.3 million and $0.2 million, respectively, and is included in depreciation, depletion and amortization in the accompanying combined statement of operations.

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Restricted Cash

Restricted cash as of December 31, 2013 and 2012 consisted of a certificate of deposit that matures in 2014.

Deferred Loan Costs

Deferred loan costs are stated at cost, net of amortization, which is computed using the straight-line method over the life of the loan which is reflective of the effective interest rate method. Deferred loan costs of $2.2 million and $1.5 million as of December 31, 2013 and 2012, respectively, net of accumulated amortization, are included in other assets in the accompanying combined balance sheets. Amortization of deferred loan costs of $1.7 million, $0.5 million and $0.4 million was recorded for the years ended December 31, 2013, 2012 and 2011, respectively.

Asset Retirement Obligation

The Predecessor 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 Predecessor 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 a field s surface 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 years indicated:

	Year Ended December 31,	
	2013	2012
	(In thousands)	
Asset retirement obligation at beginning of year	$ 2,716	$ 1,114
Liabilities acquired	296	
Liabilities incurred	348	1,474
Liabilities settled	(897)	
Revision of estimate		13
Accretion expense	121	115
Asset retirement obligation at end of year	$ 2,584	$ 2,716

Revenue Recognition

Oil, natural gas and NGL revenue is recognized when the product is sold to a purchaser, delivery has occurred, written evidence of an arrangement exists, pricing is fixed and determinable and collectability of the revenue is

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reasonably assured. Oil, natural gas and NGL imbalances result when sales differ from the seller s net revenue interest in the particular property s reserves. An imbalance receivable or liability is recognized only to the extent that the Predecessor has an imbalance on a specific property greater than the expected remaining proved reserves. As of December 31, 2013 and 2012, the Predecessor had no significant asset or liability recorded for oil, natural gas or NGL imbalances. 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.

Income Taxes

RSP and Rising Star are organized as Delaware limited liability companies and are treated as flow-through entities for federal income tax purposes. As a result, the net taxable income of the Predecessor and any related tax credits are passed through to the members and are included in their tax returns even though such net taxable income or tax credits may not have actually been distributed. Accordingly, no federal tax provision has been recorded in the financial statements of the Predecessor.

However, the Predecessor s operations located in Texas are subject to an entity-level tax, the Texas franchise tax, at a statutory rate of up to 1% of income that is apportioned to Texas. A deferred tax liability has been recognized in the combined balance sheets to reflect the future tax consequences attributable to the difference in the book and tax bases of certain assets and liabilities.

The Predecessor evaluates the tax positions taken or expected to be taken in the course of preparing its tax returns and disallows the recognition of tax positions not deemed to meet a more-likely-than-not threshold of being sustained by the applicable tax authority. The Predecessor s management does not believe that any tax positions included in its tax returns would not meet this threshold. The Predecessor s policy is to reflect interest and penalties related to uncertain tax positions as part of its income tax expense, when and if they become applicable.

Unaudited Pro Forma Income Taxes

These financial statements have been prepared in anticipation of a proposed initial public offering (the Offering) of the common stock of the Predecessor s parent entity. In connection with the Offering, all interests in RSP and certain assets of Rising Star were contributed to a newly formed Delaware corporation, which is treated as a taxable C corporation and thus is subject to federal and state income taxes. Accordingly, a pro forma income tax provision has been disclosed as if the Predecessor was a taxable corporation for the most recent period presented. The Predecessor has computed pro forma tax expense using a 36% blended corporate level federal and state tax rate. If the Predecessor had affected the change in tax status on December 31, 2013, the Predecessor would have recognized a deferred tax liability of approximately $112.4 million related to the tax basis of its long-lived assets being less than its book basis in those assets.

Unaudited Pro Forma Earnings Per Share

The Predecessor has presented pro forma earnings per share for the most recent period. Pro forma basic and diluted income per share was computed by dividing pro forma net income attributable to the Predecessor by the number of shares of common stock attributable to the Predecessor issued in the Offering, as if such shares were issued and outstanding for the year ended December 31, 2013.

Unaudited Pro Forma Distribution Payable

Staff Accounting Bulletin 1.B.3 requires that certain distributions to owners prior to or concurrent with an initial public offering be considered as distributions in contemplation of that offering. The pro forma balance sheet as of December 31, 2013 reflects the pro forma distribution accrual related to the estimated $27.8 million and $1.7 million of cash distributions expected to be made to RSP Permian Holdco, L.L.C. and Rising Star, respectively, upon the closing of the Offering. This total pro forma $29.5 million cash distribution will be funded with the net proceeds received in connection with the Offering.

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Segment Reporting

The Predecessor 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.

Concentrations of Credit Risk

Cash equivalents

The Predecessor s cash equivalents are primarily invested in funds with high-quality, short-term securities and instruments that are issued or guaranteed by the U.S. government.

Accounts receivable

The following table summarizes concentration of receivables, net of allowances, by product or service as of the following dates:

	December 31, 2013	December 31, 2012
	(In thousands)	
Receivables by product or service:		
Sale of oil and natural gas and related products and services	$ 15,618	$ 9,673
Joint interest owners	10,707	11,935
Other	21	6
Total	$ 26,346	$ 21,614

Oil and natural gas customers include pipelines, distribution companies, producers, natural gas marketers and industrial users primarily located in the Permian Basin. As a general policy, collateral is not required for receivables, but customers financial condition and credit worthiness are evaluated regularly.

Derivative assets and liabilities

The Predecessor has a risk of loss from counterparties not performing pursuant to the terms of their contractual obligations. Counterparty performance can be influenced by changes in the economy and regulatory issues, among other factors.

During the years ended December 31, 2013, 2012 and 2011, the Predecessor did not incur any significant losses due to counterparty bankruptcy filings. The Predecessor assesses its credit exposure on a net basis to reflect master netting agreements in place with certain counterparties. The Predecessor offsets its credit exposure to each counterparty with amounts it owes the counterparty under derivative contracts.

New Accounting Pronouncements

The FASB issued ASU 2011-11, *Disclosures about Offsetting Assets and Liabilities* in December 2011, and issued ASU 2013-01, *Clarifying the Scope of Disclosures About Offsetting Assets and Liabilities* in January 2013. These ASUs create new disclosure requirements regarding the nature of an entity s rights of setoff and related arrangements associated with its derivative instruments, repurchase agreements and securities lending transactions. Certain disclosures of the amounts of certain instruments subject to enforceable master netting arrangements would be required, irrespective of whether the entity has elected to offset those instruments in the statement of financial position. These ASUs are effective retrospectively for annual reporting periods beginning on or after January 1, 2013. The adoption of these ASUs will not impact the Predecessor s financial position, results of operations or liquidity.

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

Resolute Sale

Effective October 1, 2012, RSP, ACTOIL, 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 $110.0 million to Resolute Natural Resources Southwest LLC (Resolute). The Predecessor s share of the purchase price was $69.0 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 Predecessor recorded a gain on the sale. In addition, RSP and the other sellers sold Resolute an option (the Option) for $5.0 million, $2.4 million of which is the Predecessor s share. The Option allows Resolute to acquire the remaining 67.65% interest in these certain assets. The Option is non-refundable and only entitles Resolute to a limited time period during which it can exercise a 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 Predecessor recorded a gain in connection with the sale of the 32.35% interest in these assets and 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, ACTOIL and other working interest owners for an additional purchase price of approximately $230.0 million. RSP s share of the purchase price was $144.2 million. In connection with the transaction closing in March 2013, RSP recorded a gain of approximately $6.0 million.

The PSA contained customary closing conditions and included a $5.0 million title and environmental escrow (net to RSP) and an $11.0 million indemnity escrow (net to RSP) 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 Predecessor 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, the Predecessor received the first two scheduled escrow payments under the terms of the PSA totaling approximately $12.0 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 Predecessor 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 sale to Resolute was approximately $22.7 million.

Spanish Trail Acquisition

On September 10, 2013, RSP 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). Together with the working interests acquired pursuant to the preferential purchase rights and to be contributed to RSP in connection with the Offering, the Spanish Trail Acquisition increased RSP s working interests in approximately 5,400 gross acres and 70 gross producing wells (the Spanish Trail Assets).

The aggregate purchase price for the Spanish Trail Assets agreed to by RSP and the sellers was $155 million. Subsequent to the signing of the purchase agreement and prior to the closing of the Spanish Trail Acquisition, Ted Collins, Jr. (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 a newly-formed entity, Collins & Wallace Holdings, LLC, and contributed these acquired assets, along with other non-operated working interests in substantially all of RSP s assets, for shares of RSP Permian, Inc. s

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common stock in connection with the Offering. The exercise of the preferential purchase rights reduced RSP s purchase price from $155 million to $121 million. RSP 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
Sale to ACTOIL (see Note 7)	$	(30,131)
Oil and natural gas properties acquired	$	90,390
Asset retirement obligation assumed	$	296
Oil and natural gas properties	$	90,686

The Spanish Trail Acquisition was funded with a $70 million term loan, borrowings under RSP s revolving credit facility (described below in Note 6) and the issuance of a net profits interest (described below in Note 7).

Summarized below are the results of operations for the years ended December 31, 2013 and 2012, on an unaudited pro forma basis, as if the Spanish Trail acquisition had occurred on January 1, 2012.

The unaudited pro forma financial information was derived from the historical combined statements of operations of our predecessor, the statements of revenues and direct operating expenses for the Spanish Trail Properties and the historical accounting records of the sellers. 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.

	2013				2012			
	Actual		Pro Forma		Actual		Pro Forma	
	(In thousands)				(In thousands)			
Spanish Trail:								
Revenues	$	123,042	$	139,931	$	104,427	$	125,434
Net income	$	62,738	$	67,979	$	35,908	$	44,428

During the year ended December 31, 2013, approximately $6.9 million of revenue and $5.5 million of earnings were recorded in the statement of operations related to the Spanish Trail Acquisition subsequent to the closing date.

Verde Acquisition

On October 10, 2013, the Predecessor acquired leasehold interests in 9,464 gross (8,092 net) acres in the Midland Basin located just to the north of the Dawson and Martin county line toward the eastern half of Dawson County. The Predecessor is the operator on 100% of this acreage. This acreage currently contains no producing wells.

NOTE 4 DERIVATIVE INSTRUMENTS

Crude Oil Derivative Instruments

The Predecessor uses derivative instruments to manage its exposure to cash-flow variability from commodity-price risk inherent in its crude oil production. These include over-the-counter (OTC) swaps, put options, and collars with the underlying contract and settlement pricings based on NYMEX West Texas Intermediate (WTI). The derivative instruments are recorded at fair value on the combined 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 Predecessor 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

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the Predecessor an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume.

Each put transaction has an established price floor. The Predecessor pays the counterparty a premium in order to enter into the put transaction. When the settlement price is below the floor price, the counterparty pays the Predecessor an amount equal to the difference between the settlement price and the fixed price multiplied by the hedged contract volume. When the settlement price is above the floor price, the put option expires. All put options have expired as of December 31, 2013.

Each collar transaction has an established price floor and ceiling. When the settlement price is below the price floor established by these collars, the Predecessor 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 Predecessor 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, 2013:

	Year 2014	Year 2015
Swaps:		
Notional volume (Bbl)	240,000	120,000
Weighted average price ($/Bbl)	$ 94.50	$ 92.60
Collars:		
Notional volume (Bbl)	693,000	372,000
Weighted average floor price ($/Bbl)	$ 86.13	$ 84.03
Weighted average ceiling price ($/Bbl)	$ 103.59	$ 94.66

Interest Rate Derivative Instruments

The Predecessor s use of variable rate debt directly exposes it to interest rate risk. The Predecessor has historically executed interest rate swaps to fix the interest rate on a portion of the outstanding balance from the Predecessor s credit agreement. As of December 31, 2013, all of the Predecessor s interest rate swaps have expired.

Fair Values and Gains (Losses)

The following table presents the fair value of derivative instruments. The Predecessor derivatives are presented as separate line items in its combined balance sheets as current and noncurrent derivative instrument assets and liabilities. Derivative instruments are classified as current or noncurrent based on the contractual timing of expected future net cash flows of individual contracts. The expected future net cash flows for derivative instruments classified as current are expected to occur within the next 12 months. 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 Predecessor s master netting arrangements.

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	Assets December 31, 2013	Assets December 31, 2012	Liabilities December 31, 2013	Liabilities December 31, 2012
	(In thousands)			
Derivative Instruments:				
Current amounts				
Crude oil contracts	$ 671	$ 1,112	$ (1,562)	$ (417)
Interest rate contracts				(810)
Noncurrent amounts				
Crude oil contracts	1,078	2,325	(43)	(345)
Interest rate contracts				
Total derivative instruments	$ 1,749	$ 3,437	$ (1,605)	$ (1,572)

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

The following represents the Predecessor s reported gains and losses on derivative instruments for the years presented:

	For the year ended December 31, 2013	2012	2011
	(In thousands)		
Loss on derivative instruments:			
Crude oil derivative instruments	$ (2,583)	$ (408)	$ (545)
Interest rate derivative instruments	(24)	(388)	(1,434)
Total	$ (2,607)	$ (796)	$ (1,979)

Offsetting of Derivative Assets and Liabilities

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

	Gross Amount Presented on Balance Sheet	Netting Adjustments(a) (In thousands)	Net Amount
December 31, 2013			
Derivative instrument assets with right of offset or master netting agreements	$ 1,749	$ (1,332)	$ 417
Derivative instrument liabilities with right of offset or master netting agreements	$ (1,605)	$ 1,332	$ (273)
December 31, 2012			
Derivative instrument assets with right of offset or master netting agreements	$ 3,437	$ (1,373)	$ 2,064
Derivative instrument liabilities with right of offset or master netting agreements	$ (1,572)	$ 1,373	$ (199)

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

Credit Risk related Contingent Features in Derivatives

None of the Company s derivative instruments contains credit-risk related contingent features. No amounts of collateral were posted by the Predecessor related to net positions as of December 31, 2013 and 2012.

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NOTE 5 FAIR VALUE MEASUREMENTS

The Predecessor accounts for its derivative instruments at fair value. The fair value of derivative financial instruments is determined utilizing pricing models for similar instruments. The models use a variety of techniques to arrive at fair value, including quotes and pricing analysis. Inputs to the pricing models include publicly available prices and forward curves generated from a compilation of data gathered from third parties.

The Predecessor has categorized its assets and liabilities measured at fair value, based on the priority of inputs to the valuation technique, into a three-level fair value hierarchy. The fair value hierarchy gives the highest priority to quoted prices in active markets 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 audited combined 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.

Fair Value Measurement on a Recurring Basis

The following table presents, by level within the fair value hierarchy, the Predecessor s assets and liabilities that are measured at fair value on a recurring basis. The carrying amounts reported in the combined balance sheets for cash and cash equivalents approximate fair value due to the nature of the instrument and/or the short-term maturity of these instruments.

	Level 1	Level 2	Level 3	Total fair value
As of December 31, 2013:				
Crude oil derivative instruments	$	$ 144	$	$ 144
Total	$	$ 144	$	$ 144

	Level 1	Level 2	Level 3	Total fair value
As of December 31, 2012:				
Crude oil derivative instruments	$	$ 2,675	$	$ 2,675
Interest rate derivative instruments		(810)		(810)
Total	$	$ 1,865	$	$ 1,865

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Significant Level 2 assumptions used to measure the fair value of the crude oil derivative instruments include current market and contractual crude oil prices, 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, 2013 or 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 ARO represent a nonrecurring Level 3 measurement.

The Predecessor 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 CREDIT AGREEMENT

In December 2010, RSP entered into a credit agreement (the Agreement) with two participating banks (the Lenders) for the acquisition of producing and nonproducing oil and natural gas interests in the Permian Basin. The Agreement consisted of a revolving credit facility (the Revolving Credit Facility) and a term loan (the Term Loan) (collectively, the Commitments).

RSP s obligations under the Commitments are secured by a first lien on all of RSP s oil and natural gas properties. In 2011, the Agreement was syndicated and the Lenders increased to six participating banks. During 2011, the Term Loan was paid off with proceeds from the issuance of a net profits interest (See Note 7).

On September 10, 2013, in conjunction with the Spanish Trail Acquisition, RSP amended and restated the Agreement and expanded its syndicated bank group to 11 Lenders. In addition, RSP entered into a new Term Loan in the amount of $70 million to partially finance the acquisition.

The Revolving Credit Facility requires RSP to maintain the following three financial ratios:

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

- a minimum interest coverage ratio, which is the ratio of consolidated EBITDAX (as defined in the Agreement) to consolidated interest expense, of not less than 3.0 to 1.0; and

- a leverage ratio, which is the ratio of the sum of all our debt to the consolidated EBITDAX (as defined in the Agreement) for the four fiscal quarters then ended, of not greater than 4.0 to 1.0.

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RSP was in compliance with such covenants and ratios as of December 31, 2013.

The borrowing base under RSP s amended and restated Agreement is $140 million as of December 31, 2013, with lender commitments of $500 million. The maturity date of the Revolving Credit Facility is September 10, 2017 while the new Term Loan matures on April 1, 2016.

The amount available to be borrowed under the Revolving Credit Facility is subject to a borrowing base that is re-determined semiannually each May and November and depends on the volumes of proved oil and natural gas reserves and estimated cash flows from these reserves and commodity hedge positions. As of December 31, 2013, the Revolving Credit Facility has a margin of 1.25% to 2.00% plus LIBOR, plus a facility fee of 0.50% charged on the borrowing base amount, while the Term Loan has a margin of 5.5% plus LIBOR (floor of 1%), or 6.5%.

NOTE 7 NET PROFITS INTEREST

In July 2011, RSP 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 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 are to be distributed to ACTOIL for its interest is determined on a quarterly basis by RSP. ACTOIL does not fund its proportionate share of direct capital expenditures or lease operating expenses as the expenses are funded by the Predecessor 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 is a negative number, then the distribution is zero for such calendar quarter and such cumulative negative amount is carried forward. When the cumulative NPI calculation becomes a positive number at the end of a calendar quarter, a distribution will be made to ACTOIL for its share of net profits. If the NPI Account has a deficit balance at the end of a calendar quarter, ACTOIL incurs interest to RSP on the cumulative deficit balance at varying annual rates depending on the amount of the deficit balance. This interest is added to the cumulative deficit balance.

As of December 31, 2013 and 2012, the NPI Account had a cumulative deficit balance of approximately $8.3 million. The deficit balance attributable to the NPI Account is not recorded in the Predecessor s balance sheet at December 31, 2013 or 2012 because ACTOIL is not obligated to pay such balance. As such time that the NPI computation reflects a net positive balance at the end of a quarter, the positive balance will be reflected as a payable to ACTOIL in the balance sheet and a distribution to ACTOIL will be reflected in the combined statement of operations for that quarter.

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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NOTE 8 MAJOR CUSTOMERS AND SUPPLIERS

Dependence on Major Customers

The Predecessor believes, due to the competitive nature of goods and services supporting the oil and natural gas industry, plus access to several marketing alternatives, the Predecessor 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,		
	2013	2012	2011
Shell Trading (US) Company	40%	3%	
Enterprise Crude Oil LLC	14%		
Diamondback E&P, LLC	11%	2%	
Coronado Midstream, LLC	8%	11%	9%
Plains Marketing, L.P.	13%	76%	78%

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 Predecessor can establish such relationships or that those relationships will result in an increased number of purchasers. Although the Predecessor is exposed to a concentration of credit risk, management believes that all of the Predecessor s purchasers are credit worthy.

NOTE 9 MEMBERS EQUITY

RSP s operations are governed by the provisions of a limited liability company agreement (the RSP LLC Agreement). As of December 31, 2013, 2012 and 2011, the members of RSP had contributed $185.1 million, $184.8 million and $184.8 million, respectively, to RSP. There are no current outstanding equity commitments of the members. Allocations of net income and loss are allocated to the members based on a hypothetical liquidation.

Limitations of Member s liabilities

Pursuant to the RSP LLC Agreement (and as is customary for limited liability companies), the liability of the members is limited to their contributed capital.

Incentive Units

As part of the RSP LLC Agreement, certain incentive units are available to be issued to management and employees of RSP, consisting of Tier I, Tier I A, Tier II, Tier III and Tier IV units. The incentive units are intended to be compensation for services rendered to RSP. All incentive units, whether vested or not, are forfeited if payouts are not achieved by a specified date. Substantially all of the incentive unit grants were issued to members of management on October 18, 2010. The original terms of the incentive units are as follows. 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.

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The achievement of these payout conditions is a performance condition that requires the Predecessor 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, the Predecessor 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 Predecessor 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. As of December 31, 2013, the unrecognized non-cash compensation expense associated with all tiers of the incentive units is approximately $16.3 million. We expect that upon successful completion of the Offering, the performance conditions associated with the Tier I, Tier I A and Tier II incentive units will be deemed probable of reaching payout, which will result in the recognition of non-cash compensation expense of approximately $11.1 million. The Tier I A and Tier II incentive units will have a remaining unrecognized non-cash compensation expense of approximately $1.6 million which will be amortized over the remaining service period and result in a $0.7 million non-cash compensation expense in the remainder of 2014 and $0.9 million in 2015. The remaining unrecognized non-cash compensation expense related to the Tier III and Tier IV incentive units is approximately $3.5 million and will be recognized when it is deemed that the Tier III and Tier IV incentive units are probable of reaching payout as a result of reaching the established distribution thresholds.

NOTE 10 COMMITMENTS AND CONTINGENCIES

Legal Matters

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

Environmental Matters

The Predecessor 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 Predecessor 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 Predecessor has established procedures for the ongoing evaluation of its operations, to identify potential environmental exposures and to comply with regulatory policies and procedures.

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

Liabilities are recorded when environmental assessments and/or clean-ups are probable, and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. At December 31, 2013 and 2012, the Predecessor had no environmental matters requiring specific disclosure or requiring the recognition of a liability.

Leases

During 2011, RSP entered into a month-to-month operating lease agreement and a long-term operating lease agreement for office space. Rent expense for each year ended December 31, 2013, 2012 and 2011 was $0.2 million.

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NOTE 11 SUPPLEMENTAL DISCLOSURE OF OIL AND NATURAL GAS OPERATIONS (UNAUDITED)

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

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

	2013	2012 (In thousands)	2011
Property acquisition costs:			
Proved	$ 86,958	$	$
Unproved	7,875		
Exploration costs			
Development costs	136,832	173,983	95,654
Total costs incurred	$ 231,665	$ 173,983	$ 95,654

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:

	2013	2012
	(In thousands)	
Capitalized costs:		
Proved	$ 562,019	$ 447,369
Unproved	33,467	29,447
	$ 595,486	$ 476,816
Less accumulated depreciation, depletion, amortization and impairment	(88,514)	(60,489)
Net capitalized costs	$ 506,972	$ 416,327

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:

	2013	2012 (In thousands)	2011
Revenues:			
Oil and natural gas sales	$ 123,042	$ 104,427	$ 63,989
Production costs:			
Lease operating expenses	14,664	12,854	5,712
Production and ad valorem taxes	8,326	7,575	4,192
	100,052	83,998	54,085
Other costs:			
Depreciation, depletion, amortization and impairment	47,158	48,803	16,612
Income tax (expense) benefit	(2,262)	339	(550)
Results of operations	$ 50,632	$ 35,534	$ 36,923

Net Proved Oil and Natural Gas Reserves

The Predecessor s proved oil and natural gas reserves as of December 31, 2013 were prepared by independent third party petroleum consultants. The Predecessor s proved oil and natural gas reserves as of December 31, 2012

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were prepared internally by management. In accordance with the new SEC regulations, reserves at December 31, 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, 2013 and 2012 is as follows:

	Year Ended December 31, 2013			
	Natural Gas (MMcf)	Oil (MBbls)	NGLs (MBbls)	MBoe
Proved developed and undeveloped reserves:				
Beginning of year	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)
End of year	35,803	23,732	6,913	36,613
Proved developed reserves:				
Beginning of year	17,847	7,730	1,723	12,427
End of year	14,396	9,533	2,703	14,636
Proved undeveloped reserves:				
Beginning of year	22,845	13,133	3,233	20,173
End of year	21,407	14,199	4,210	21,977

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	Year Ended December 31, 2012			
	Natural Gas (MMcf)	Oil (MBbls)	NGLs (MBbls)	MBoe
Proved developed and undeveloped reserves:				
Beginning of year	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)
End of year	40,692	20,863	4,956	32,600
Proved developed reserves:				
Beginning of year	19,825	7,550		10,854
End of year	17,847	7,730	1,723	12,427
Proved undeveloped reserves:				
Beginning of year	72,591	25,821		37,920
End of year	22,845	13,133	3,233	20,173

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, 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, 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%.

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The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves is as follows at December 31:

	2013	2012 (In thousands)	2011
Future cash inflows	$ 2,547,566	$ 2,210,325	$ 3,825,056
Future production costs	(727,939)	(655,720)	(759,190)
Future development costs	(378,695)	(362,876)	(505,710)
Future income tax expenses(1)			
Future net cash flows	1,440,932	1,191,729	2,560,156
10% discount for estimated timing of cash flows	(890,217)	(737,556)	(1,705,732)
Standardized measure of discounted future net cash flows	$ 550,715	$ 454,173	$ 854,424

(1) Future net cash flows 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 as of December 31, 2013, December 31, 2012 and December 31, 2011. 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 the completion of the Offering, the Company will become 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, December 31, 2012 and December 31, 2011 would have been $247,397, $155,662, and $289,022, respectively. The unaudited standardized measure at December 31, 2013, December 31, 2012 and December 31, 2011 would have been $303,318, $298,511 and $565,402, respectively.

In the foregoing determination of future cash inflows, sales prices used for gas and oil for December 31, 2013, 2012 and 2011 were estimated using the average price during the 12-month period, determined as the unweighted arithmetic average of the first-day-of-the-month price for each month. Prices were adjusted by lease for quality, transportation fees and regional price differentials. Future costs of developing and producing the proved gas and oil reserves reported at the end of each year shown were based on costs determined at each such year-end, assuming the continuation of existing economic conditions.

It is not intended that the FASB s standardized measure of discounted future net cash flows represent the fair market value of the Predecessor s proved reserves. The Company cautions that the disclosures shown are based on estimates of proved reserve quantities and future production schedules which are inherently imprecise and subject to revision, and the 10% discount rate is arbitrary. In addition, costs and prices as of the measurement date are used in the determinations, and no value may be assigned to probable or possible reserves.

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

	2013	2012 (In thousands)	2011
Standardized measure of discounted future net cash flows, beginning of year	$ 454,173	$ 854,424	$ 660,480
Changes in the year resulting from:			
Sales, less production costs	(100,052)	(83,998)	(54,085)
Revisions of previous quantity estimates	(53,557)	(439,043)	(73,407)
Extensions, discoveries and other additions	157,086	84,149	32,525
Net change in prices and production costs	45,388	(133,485)	118,588
Changes in estimated future development costs	2,318	38,096	(1,514)
Previously estimated development costs incurred during the period	46,938	108,367	76,086
Divestiture of reserves	(151,440)		
Purchases of minerals in place	94,751		
Accretion of discount	45,417	85,442	66,048
Net change in income taxes			
Timing differences and other	9,693	(59,779)	29,703
Standardized measure of discounted future net cash flows, end of year	$ 550,715	$ 454,173	$ 854,424

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 12 SUBSEQUENT EVENTS

On January 23, 2014, RSP Permian, Inc. (RSP Inc.) completed the Offering of common stock to the public. Shares of common stock of RSP Inc. began trading on the New York Stock Exchange under the ticker RSPP on January 17, 2014. Concurrent with the completion of the Offering, all interests in RSP and certain assets of Rising Star were contributed to RSP Inc. RSP Inc. sold 23 million shares at $19.50 per share, raising $449 million of gross proceeds. Of the 23 million shares issued to the public, 9.2 million were primary shares issued by RSP Inc., resulting in $166 million of net proceeds, which were used to retire the $70 million Term Loan, repay the Revolving Credit Facility balance of $56 million in its entirety, pay cash as partial consideration for certain working interest in oil and gas properties contributed in conjunction with the Offering (described below), and for other general corporate purposes. The remaining 13.8 million shares sold in the Offering were sold by selling stockholders and RSP Inc. did not receive any proceeds from the sale of those shares.

In connection with the Offering, several transactions occurred simultaneously which changed the structure and scope of RSP.

- Corporate Reorganization:

- RSP was contributed to RSP Permian Holdco L.L.C., a newly formed limited liability company which simultaneously contributed all of its interests in RSP to RSP Inc. in exchange for shares of RSP Inc. s common stock and cash. As a result, RSP became a wholly owned subsidiary of RSP Inc.

- The Rising Star Acquisition:

- RSP acquired from Rising Star certain acreage and wells in the Permian Basin in which RSP already had working interests in for shares of RSP Inc. s common stock and cash.

- The Collins and Wallace Contributions:

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• Ted Collins, Jr. (Collins), Wallace LP and a newly formed entity, Collins & Wallace Holdings, LLC, that is jointly owned by Collins and Wallace LP contributed to RSP certain working interests. In exchange, Collins and Wallace LP received both cash and shares of RSP Inc. s common stock and Collins & Wallace Holdings, LLC received only shares of RSP Inc. s common stock. RSP Inc. is in the process of evaluating the fair values of the contributed assets in order to determine the appropriate purchase price allocation.

• The Pecos Contribution:

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

• The ACTOIL NPI Repurchase:

• ACTOIL, the owner of a 25% NPI issued by RSP, contributed to RSP its 25% NPI in exchange for shares of RSP Inc. s common stock. RSP Inc. is in the process of evaluating the fair values of the contributed assets in order to determine the appropriate purchase price allocation.

Subsequent to year-end, RSP has closed approximately $79 million of acquisitions. On February 28, 2014, RSP closed the acquisition of a 17.5% non-operated working interest in producing properties located in Martin County, Texas. The properties are contiguous to RSP operated leasehold positions in Martin County. In addition, RSP added additional undeveloped leasehold in Glasscock County and Dawson County during the first quarter of 2014.

The Predecessor has evaluated subsequent events through the date that these financial statements were available to be issued. Except as described above, the Predecessor determined there were no additional events that required disclosure or recognition in these financial statements.

NOTE 13 - QUARTERLY FINANCIAL DATA (Unaudited)

The Company s unaudited quarterly financial data for 2013 and 2012 is summarized below.

	2013			
	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**

Revenues	$	24,749	$	25,053	$	36,860	$	36,380
Income from operations		2,784		19,278		27,039		22,520
Income tax (expense) benefit				(68)				(2,194)
Net income	$	471	$	20,254	$	24,037	$	17,976
Pro forma information:								
Net income	$	471	$	20,254	$	24,037	$	17,976
Pro forma provision for income taxes		170		7,291		8,653		6,472
Pro forma net income		301		12,963		15,384		11,504
Earnings per share:								
Basic and diluted	$	0.01	$	0.41	$	0.48	$	0.36

	2012							
		First Quarter		Second Quarter		Third Quarter		Fourth Quarter
Revenues	$	24,538	$	26,195	$	26,895	$	26,799
Income from operations		12,086		13,291		14,476		(898)
Income tax (expense) benefit		(137)		97		405		(26)
Net income (loss)	$	6,564	$	23,174	$	8,865	$	(2,695)

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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 10, 2014).
4.2	Registration Rights Agreement, dated as of January 23, 2014, among RSP Permian, Inc., 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. 001-36273) filed with the Commission on January 29, 2014).
4.3	Stockholders Agreement, dated as of January 23, 2014, among RSP Permian, Inc., 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. 001-36273) filed with the Commission on January 29, 2014).
10.1	Credit Agreement, dated September, 10, 2013, by and between 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. 377-00338) filed with the Commission on October 8, 2013).
10.2	Amended and Restated Liability Company Agreement of RSP Permian Holdco, L.L.C., dated January 23, 2014 (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 29, 2014).
10.3	Indemnification Agreement (incorporated by reference to Exhibit 10.4 to the Company s Registration Statement on Form S-1 (File No. 333-192268) filed with the Commission on January 2, 2014).
10.4	RSP Permian, Inc. 2014 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company s Current Report on Form 8-K (File No. 001-36264) filed with the Commission on January 16, 2014).
21.1(a)	List of Subsidiaries of RSP Permian, Inc.
23.1(a)	Consent of Grant Thornton LLP.
23.2(a)	Consent of Grant Thornton LLP.
23.3(a)	Consent of Ryder Scott Company, L.P.
23.4(a)	Consent of Ryder Scott Company, L.P.
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 Section 906 of the Sarbanes-Oxley Act of 2002 by Chief Executive Officer.
32.2(b)	Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 by Chief Financial Officer.
99.1(a)	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2013.
99.2(a)	Ryder Scott Company, L.P., Summary of Reserves at December 31, 2013.

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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 this Report for purposes of Section 18 of the Securities Exchange Act, as amended, or otherwise subject to the liability of Section 18 of the Securities Exchange Act, as amended, and this certification will not be deemed to be incorporated by reference into any filing under the Securities Exchange Act of 1933, as amended, except to the extent that the registrant specifically incorporates it by reference.