Memorial Resource Development Corp.
Form 10-K
March 18, 2015

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10–K

þ ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2014

OR

¨ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
Commission File Number: 001-36490

MEMORIAL RESOURCE DEVELOPMENT CORP.

(Exact name of registrant as specified in its charter)

Delaware	46-4710769
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
500 Dallas Street, Suite 1800, Houston, TX	77002
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (713) 588-8300

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

Common Stock, par value $0.01 per share	NASDAQ Global Market
(Title of each class)	(Name of each exchange on which registered)

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 ¨ No þ

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

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 þ No ¨

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S–K 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 or any amendment to the Form 10–K þ

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 "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b–2 of the Exchange Act. Check one:

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b–2 of the Exchange Act). Yes ¨ No þ

The aggregate market value of the voting and non-voting common equity held by non-affiliates as of June 30, 2014 computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such equity was $1.2 billion.

As of March 1, 2015, the registrant had 191,757,539 outstanding shares of common stock, $0.01 par value outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the Annual Meeting of Stockholders to be held on May 15, 2015, to be filed with the Securities and Exchange Commission within 120 days after December 31, 2014, are incorporated by reference into Part III of this Form 10-K.

MEMORIAL RESOURCE DEVELOPMENT CORP.

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GLOSSARY OF OIL AND NATURAL GAS TERMS

Analogous Reservoir: Analogous reservoirs, as used in resource assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, analogous reservoir refers to a reservoir that shares all of the following characteristics with the reservoir of interest: (i) the same geological formation (but not necessarily in pressure communication with the reservoir of interest); (ii) the same environment of deposition; (iii) similar geologic structure; and (iv) the same drive mechanism.

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

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

Bcf: One billion cubic feet of natural gas.

Bcfe: One billion cubic feet of natural gas equivalent.

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.

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

Developed Acreage: The number of acres which are allocated or assignable to producing wells or wells capable of production.

Development Well: A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Differential: An adjustment to the price of oil or natural gas from an established spot market price to reflect differences in the quality and/or location of oil or natural gas.

Economically Producible: The term economically producible, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. For this determination, the value of the products that generate revenue are determined at the terminal point of oil and natural gas producing activities.

Estimated Ultimate Recovery (EUR): Estimated ultimate recovery is the sum of proved reserves remaining as of a given date and cumulative production as of that date.

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

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

Field: An area consisting of a single reservoir or multiple reservoirs, all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

Gross Acres or Gross Wells: The total acres or wells, as the case may be, in which we have working interest.

ICE: Inter-Continental Exchange.

MBtu/d: One thousand Btu per day.

Mcf: One thousand cubic feet of natural gas.

MMBtu: One million British thermal units.

MMcf: One million cubic feet of natural gas.

MMcfe: One million cubic feet of natural gas equivalent.

Net Acres or Net Wells: Gross acres or wells, as the case may be, multiplied by our working interest ownership percentage.

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

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

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

NYMEX: New York Mercantile Exchange.

Oil: Oil and condensate.

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

Play: A geographic area with hydrocarbon potential.

Possible Reserves: Reserves that are less certain to be recovered than probable reserves.

Probable Reserves: Reserves that are less certain to be recovered than proved reserves but that, together with proved reserves, are as likely as not to be recovered.

Productive Well: A well that produces commercial quantities of hydrocarbons, exclusive of its capacity to produce at a reasonable rate of return.

Proved Developed Reserves: Proved reserves that can be expected to be recovered from existing wells with existing equipment and operating methods.

Proved Reserves: 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. The project to extract the hydrocarbons must have commenced, or the operator must be reasonably certain that it will commence the project, within a reasonable time. The area of the reservoir considered as proved includes (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons, as seen in a well penetration, unless geoscience, engineering or performance data and reliable technology establishes a lower contact with reasonable certainty. Where direct observation from well penetrations has defined a highest known oil elevation and the potential exists for an associated natural gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including fluid injection) are included in the proved classification when (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir, or an analogous reservoir or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price used is the average price during the twelve-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

PUDs: Proved Undeveloped Reserves.

Proved Undeveloped Reserves: Proved oil and natural gas reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Under no circumstances should estimates for proved undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Standardized Measure: The present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules, regulations or standards established by the United States Securities and Exchange Commission ("SEC") and the Financial Accounting Standards Board ("FASB") (using prices and costs in effect as of the date of estimation), less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue. Because we are a corporation, we are subject to federal or state income taxes and thus make provision for federal or state income taxes in the calculation of our standardized measure. Standardized measure does not give effect to derivative transactions.

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

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

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

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

Reserves: Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible, as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

Reservoir: A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reserves.

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

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.

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.

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

Working Interest: An interest in an oil and natural gas lease that gives the owner of the interest the right to drill for and produce oil and natural gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations.

WTI: West Texas Intermediate.

Commonly Used Defined Terms

As used in this Form 10-K, unless we indicate otherwise:

- "the Company," "we," "our," "us" and "our company" or like terms refer collectively to (i) Memorial Resource Development Corp. and its subsidiaries (other than MEMP and its subsidiaries) for periods after the restructuring transactions described below and (ii) our predecessor (as described below) other than MEMP and its subsidiaries for periods prior to the restructuring transactions;
- "Memorial Production Partners," "MEMP" and "the Partnership" refer to Memorial Production Partners LP individually and collectively with its subsidiaries, as the context requires. We own the general partner of MEMP as well as 50% of MEMP's incentive distribution rights;
- "MEMP GP" refers to Memorial Production Partners GP LLC, the general partner of the Partnership, which we own;
- "MRD Holdco" refers to MRD Holdco LLC, a holding company controlled by the Funds that, together as part of a group owns a majority of our common stock;
- "MRD LLC" refers to Memorial Resource Development LLC, which historically owned our predecessor's business and was merged into MRD Operating LLC ("MRD Operating"), our 100% owned subsidiary, subsequent to our initial public offering;
- "WildHorse Resources" refers to WildHorse Resources, LLC, which owned our interest in the Terryville Complex and merged into MRD Operating in February 2015;
- "our predecessor" refers collectively to MRD LLC and its former consolidated subsidiaries, consisting of Classic Hydrocarbons Holdings, L.P., Classic Hydrocarbons GP Co., L.L.C., Black Diamond Minerals, LLC, Beta Operating Company, LLC, MEMP GP, BlueStone, MRD Operating LLC, WildHorse Resources, Tanos Energy LLC and each of their respective subsidiaries, including MEMP and its subsidiaries;
- "the Funds" refers collectively to Natural Gas Partners VIII, L.P., Natural Gas Partners IX, L.P. and NGP IX Offshore Holdings, L.P., which collectively control MRD Holdco;
- "restructuring transactions" means the transactions that took place in connection with and shortly after the closing of our initial public offering, and pursuant to which we acquired substantially all of the assets of MRD LLC (not including its interests in BlueStone, MRD Royalty, MRD Midstream, Golden Energy Partners LLC, Classic Pipeline or MEMP subordinated units);
- "BlueStone" refers to BlueStone Natural Resources Holdings, LLC, a subsidiary of MRD Holdco that sold substantially all of its assets in July 2013 for approximately $117.9 million;
- "NGP" refers to Natural Gas Partners, a family of private equity investment funds organized to make direct equity investments in the energy industry, including the Funds;
- "MRD Royalty" refers to MRD Royalty LLC, a subsidiary of MRD Holdco that owns certain immaterial leasehold interests and overriding royalty interests in Texas and Montana;
- "MRD Midstream" refers to MRD Midstream LLC, a subsidiary of MRD Holdco that owns an indirect interest in certain midstream assets in North Louisiana; and
- "Classic Pipeline" refers to Classic Pipeline & Gathering, LLC, a subsidiary of MRD Holdco that owns certain immaterial midstream assets in Texas.

FORWARD–LOOKING STATEMENTS

This Annual Report on Form 10-K contains “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended (the “Securities Act”), and Section 21E of the Securities Exchange Act of 1934, as amended (the “Exchange Act”). Forward-looking statements, which are subject to a number of risks and uncertainties, many of which are beyond our control, may include statements about our:

- business strategy;
- estimated reserves and the present value thereof;
- technology;
- cash flows and liquidity;
- financial strategy, budget, projections and future operating results;
- realized commodity prices;
- timing and amount of future production of reserves;
- ability to procure drilling and production equipment;
- ability to procure oilfield labor;
- the amount, nature and timing of capital expenditures, including future development costs;
- ability to access, and the terms of, capital;
- drilling of wells, including statements made about future horizontal drilling activities;
- competition;
- expectations regarding government regulations;
- marketing of production and the availability of pipeline capacity;
- exploitation or property acquisitions;
- costs of exploiting and developing our properties and conducting other operations;
- expectations regarding general economic and business conditions;
- competition in the oil and natural gas industry;
- effectiveness of our risk management activities;
- environmental and other liabilities;
- counterparty credit risk;
- expectations regarding taxation of the oil and natural gas industry;
- expectations regarding developments in other countries that produce oil and natural gas;
- future operating results;
- plans and objectives of management; and
- plans, objectives, expectations and intentions contained in this report that are not historical.

These types of statements, other than statements of historical fact included in this report, are forward-looking statements. These forward-looking statements may be found in “Item 1. Business,” “Item 1A. Risk Factors,” “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and other sections of this report. In some cases, you can identify forward-looking statements by terminology such as “may,” “will,” “could,” “should,” “expect,” “plan,” “project,” “forecast,” “intend,” “anticipate,” “believe,” “estimate,” “predict,” “potential,” “pursue,” “target,” the negative of such terms or other comparable terminology. These statements discuss future expectations, contain projections of results of operations or of financial condition or include other “forward-looking” information. These forward-looking statements involve risks and uncertainties. Important factors that could cause our actual results or financial condition to differ materially from our expectations include, but are not limited to, the following risks and uncertainties:

· variations in the market demand for, and prices of, oil, natural gas and NGLs;
· uncertainties about our estimated reserves;
· the adequacy of our capital resources and liquidity including, but not limited to, access to additional borrowing capacity under our revolving credit facility;
· general economic and business conditions;
· risks associated with negative developments in the capital markets;
· failure to realize expected value creation from property acquisitions;
· uncertainties about our ability to replace reserves and economically develop our current reserves;
· drilling results;
· potential financial losses or earnings reductions from our commodity price risk management programs;
· adoption or potential adoption of new governmental regulations;
· the availability of capital on economic terms to fund our capital expenditures and acquisitions;
· risks associated with our substantial indebtedness; and
· our ability to satisfy future cash obligations and environmental costs.

The forward-looking statements contained in this report are largely based on our expectations, which reflect estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions and other factors. Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. In addition, management’s assumptions about future events may prove to be inaccurate. All readers are cautioned that the forward-looking statements contained in this report are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or that the events or circumstances described in any forward-looking statement will occur. Actual results may differ materially from those anticipated or implied in the forward-looking statements due to factors described in “Item 1A. Risk Factors” and elsewhere in this report. All forward-looking statements speak only as of the date on which they are made. We do not intend to update or revise any forward-looking statements as a result of new information, future events or otherwise. These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

PART I

ITEM 1. BUSINESS

The Company is a Delaware corporation formed in January 2014. We have two reportable business segments, both of which are engaged in the acquisition, exploration, and development of oil and natural gas properties:

- MRD—reflects the combined operations of the Company, MRD Operating, MRD LLC, WildHorse Resources and its previous owners, Classic and Classic GP, Black Diamond, BlueStone, Beta Operating and MEMP GP.
- MEMP—reflects the combined operations of MEMP, its previous owners, and certain historical dropdown transactions that occurred between MEMP and other MRD LLC consolidating subsidiaries.

Because we control MEMP through our ownership of its general partner, its business and operations are consolidated with ours for financial reporting purposes, even though we do not own any of its common units. As a result, our financial statements and notes thereto included under "Item 8. Financial Statements and Supplementary Data" consolidate MEMP's business and assets with ours; however, the MEMP Segment's debt is nonrecourse to the Company. Except where expressly noted to the contrary, the following discussion of our business, operations and assets and the use of the terms "we", "our" and "us" excludes MEMP's business, operations and assets.

The consolidated financial statements included in "Item 8. Financial Statements and Supplementary Data" contain information on our segments and geographical areas and are contained herein.

As discussed under Note 2 of the Notes to Consolidated and Combined Financial Statements included under "Item 8. Financial Statements and Supplementary Data," the FASB issued an accounting standards update to improve consolidation guidance for certain types of legal entities in February 2015. The guidance, among other things, modifies the evaluation of whether limited partnerships and similar legal entities are variable interest entities ("VIEs") or voting interest entities and eliminates the presumption that a general partner should consolidate a limited partnership. We will either: (i) continue to consolidate MEMP and become subject to the VIE primary beneficiary disclosure requirements or (ii) no longer consolidate MEMP under the revised VIE consolidation requirements and provide disclosures that apply to variable interest holders that do not consolidate a VIE. The deconsolidation of MEMP would have a material impact on our consolidated financial statements and related disclosures.

MRD

Overview

We are an independent natural gas and oil company focused on the acquisition, exploration and development of natural gas and oil properties with a majority of our activity in the Terryville Complex of North Louisiana, where we are targeting overpressured, liquids-rich natural gas opportunities in multiple zones in the Cotton Valley formation. We are focused on creating shareholder value primarily through the development of our sizeable horizontal inventory.

As of December 31, 2014, our total leasehold position was 335,687 gross (210,854 net) acres. As of December 31, 2014, we had estimated proved reserves of approximately 1,632 Bcfe. As of such date, we operated 99.6% of our proved reserves, 72% of which were natural gas. For the year ended December 31, 2014, 58% of our revenues were attributable to natural gas production, 21% to NGLs and 21% to oil.

Our average net daily production for the year ended December 31, 2014 was approximately 226.9 MMcfe/d (approximately 77% natural gas, 16% NGLs and 7% oil) and our reserve life was approximately 20 years. The Terryville Complex represented 81% of our total net production for the year ended December 31, 2014. As of

December 31, 2014, we produced from 129 horizontal wells and 659 vertical wells. During 2014, we completed and brought online 31 horizontal wells in the Terryville Complex, bringing our total number of producing horizontal wells to 52 in our primary formations as of December 31, 2014.

Recent Developments

On February 23, 2015, we and MEMP completed a transaction (the “Property Swap”) in which we exchanged certain of our oil and gas properties in East Texas and non-core Louisiana for MEMP’s North Louisiana oil and gas properties and approximately $78.0 million in cash, subject to customary adjustments. Terms of the transaction were approved by our board of directors and by its conflicts committee, which is comprised entirely of independent directors. The transaction had an effective date of January 1, 2015.

2014 Developments

MRD Segment

In June 2014, we completed our initial public offering of 49,220,000 shares of common stock at a price to the public of $19.00 per share. Of the 49,220,000 shares offered, 21,500,000 were offered by us and 27,720,000 were offered by the selling stockholder, MRD Holdco. We did not receive any proceeds from the sale of shares by MRD Holdco. We used the net proceeds of approximately $380.2 million from our sale of shares in our initial public offering (i) to redeem the 10.00%/10.75% Senior PIK toggle notes due 2018 (the "PIK notes") issued by MRD LLC in their entirety and to pay the applicable premium in connection with such redemption and accrued and unpaid interest to the date of redemption, (ii) together with borrowings of approximately $614.5 million under our $2.0 billion revolving credit facility entered into in connection with the closing of our initial public offering, to make a cash payment to certain former management members of WildHorse Resources in connection with their contribution to us of their membership interests and incentive units in WildHorse Resources, (iii) to repay borrowings outstanding under WildHorse Resources' revolving credit facility and second lien term loan, which we refer to collectively as WildHorse Resources' credit agreements, (iv) to reimburse MRD LLC for interest paid on the PIK notes and (v) to pay costs associated with our revolving credit facility.

In July 2014, we completed a private placement of $600.0 million aggregate principal amount of 5.875% senior unsecured notes (the "MRD Senior Notes") at par. The MRD Senior Notes will mature on July 1, 2022. Interest on the MRD Senior Notes is payable semiannually on January 1 and July 1 of each year, commencing on January 1, 2015. The net proceeds were used to repay a portion of the borrowings outstanding under our revolving credit facility.

In December 2014, our Board of Directors (the "Board") authorized the repurchase of up to $50.0 million of the Company's outstanding common stock. Under the share repurchase program, shares may be repurchased from time to time at the Company's discretion on the open market, through block trades or otherwise and are subject to market conditions, as well as corporate, regulatory, and other considerations. Through March 16, 2015, we repurchased $50.0 million shares of common stock, which represents a repurchase of 2,888,684 shares of common stock. MRD has retired all of the shares of common stock repurchased and the shares of common stock are no longer issued or outstanding.

MEMP Segment

Acquisitions of Oil and Gas Properties

In July 2014, MEMP acquired certain oil and natural gas liquids properties in Wyoming from a third party for a purchase price of approximately $906.1 million (the "MEMP Wyoming Acquisition").

In March 2014, MEMP acquired certain oil and natural gas producing properties in the Eagle Ford from a third party for a purchase price of approximately $168.1 million (the "Eagle Ford Acquisition"). In addition, MEMP acquired a 30% interest in the seller's Eagle Ford leasehold.

2022 Senior Notes Offering

In July 2014, MEMP and its wholly-owned subsidiary Memorial Production Finance Corporation ("Finance Corp." and, together with MEMP, the "MEMP Issuers") completed a private placement of $500.0 million aggregate principal amount of 6.875% senior unsecured notes due 2022 (the "2022 Senior Notes"). The 2022 Senior Notes were issued at 98.485% of par and are fully and unconditionally guaranteed (subject to customary release provisions) on a joint and several basis by the subsidiary guarantors named in the indenture and by certain future subsidiaries of MEMP's. The 2022 Senior Notes will mature on August 1, 2022 with interest accruing at 6.875% per annum and payable semi-annually in arrears on February 1 and August 1 of each year, commencing on February 1, 2015. The indenture contains customary covenants and restrictive provisions, many of which will terminate if at any time no default exists under the indenture and the 2022 Senior Notes receive an investment grade rating from both of two specified ratings agencies. The indenture also provides for customary and other events of default. In the case of an event of default arising from certain events of bankruptcy or insolvency with respect to either of the MEMP Issuers or certain of MEMP's subsidiaries, all outstanding 2022 Senior Notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of the then outstanding 2022 Senior Notes may declare all the 2022 Senior Notes to be due and payable immediately. The net proceeds from the notes offering were used to repay a portion of the outstanding borrowings under MEMP's revolving credit facility and for general partnership purposes. In January 2015, MEMP repurchased a principal amount of approximately $3.0 million of the 2022 Senior Notes at an average price of 83.000% of the face value of the 2022 Senior Notes. For information regarding the Senior Notes, see Note 8 of the Notes to Consolidated and Combined Financial Statements included under "Item 8. Financial Statements and Supplementary Data."

2014 Equity Offerings

In September 2014, MEMP sold 14,950,000 common units in a public offering (including 1,950,000 common units purchased pursuant to the full exercise of the underwriters' option to purchase additional common units). In July 2014, MEMP sold 9,890,000 common units in a public offering (including 1,290,000 common units purchased pursuant to the full exercise of the underwriters' option to purchase additional common units). The net proceeds of approximately $541.3 million from these equity offerings were used to repay a portion of the outstanding borrowings under MEMP's revolving credit facility.

MEMP Repurchase Program

In December 2014, the board of directors of MEMP GP authorized the repurchase of up to $150.0 million of MEMP's common units. Under the common unit repurchase program, common units may be repurchased from time to time at MEMP's discretion on the open market. The common unit repurchase program does not obligate MEMP to repurchase any dollar amount or specific number of common units and may be discontinued at any time. Through February 1, 2015, MEMP repurchased $41.4 million in common units, which represents a repurchase of 2,809,495 common units. MEMP has retired all common units repurchased and the common units are no longer issued or outstanding.

Our Properties

Cotton Valley—Overview

The Cotton Valley formation extends across East Texas, North Louisiana and Southern Arkansas. The formation has been under development since the 1930s and is characterized by thick, multi-zone natural gas and oil reservoirs with well-known geologic characteristics and long-lived, predictable production profiles. Over 21,000 vertical wells have been completed throughout the play. In 2005, operators started redeveloping the Cotton Valley using horizontal drilling and advanced hydraulic fracturing techniques.

Cotton Valley—Terryville Complex

We are currently engaged in the horizontal redevelopment of the Terryville Complex in Lincoln Parish, Louisiana utilizing horizontal drilling and completion techniques similar to those employed at the Nan-Su-Gail Field, Carthage Complex in East Texas and other major resource plays across the United States. We have assembled a largely contiguous acreage position in the Terryville Complex of approximately 73,737 gross (61,157 net) acres as of December 31, 2014.

We entered the Terryville Complex via an acquisition from Petrohawk Energy Corporation in April 2010, with the goal of redeveloping the field with horizontal drilling and modern completion techniques. Since that acquisition, we have completed multiple bolt-on acquisitions and in-fill leases to build our current position. We believe the Terryville Complex, which has been producing since 1954, is one of North America's most prolific natural gas fields, characterized by high recoveries relative to drilling and completion costs, high initial production rates with high liquids yields, long reserve life, multiple stacked producing zones, available infrastructure and a large number of service providers.

After initially drilling eight vertical pilot wells in the Terryville Complex, we commenced a horizontal drilling program in 2011 to further delineate and define our position. In 2013, we shifted our operational focus to a full-scale horizontal redevelopment of the Terryville Complex, going from two rigs to four rigs by the end of that year. Additionally, in the fourth quarter of 2013, we moved to drilling on multi-well pads that allow us to more efficiently drill wells and control costs as we develop our stacked pay zones.

Within the Terryville Complex, as of December 31, 2014, we had 1,347 Bcfe of estimated proved reserves and a drilling inventory consisting of 141 gross proved horizontal drilling locations to which we have attributed proved undeveloped reserves as of December 31, 2014. Since initiating our horizontal drilling program in 2011, we have drilled 52 gross horizontal wells in the four primary target zones in the Terryville Complex. Within the Terryville Complex, on a proved reserves basis, we operate approximately 100% of our existing acreage and hold an average working interest of approximately 83% across our acreage.

We expect our redevelopment program to continue to target four of the stacked overpressured pay zones in the Cotton Valley formation—zones we term the Upper Red, Lower Red, Lower Deep Pink and Upper Deep Pink, all of which we are developing with horizontal wells through pad drilling. These four zones have an overall thickness ranging from 525 to 925 feet across our acreage position. Further, we believe there are additional opportunities for redevelopment in the zones above the four main zones.

Based on our reserve report, the Terryville Complex contains more than 15% of our total estimated reserves. The following table summarizes production volumes for the years ended December 31, 2014, 2013 and 2012:

	For the Year Ended December 31,		
	2014	2013	2012
Production Volumes:			
Oil (MBbls)	716	386	212
NGLs (MBbls)	1,763	1,118	605
Natural gas (MMcfe)	52,512	24,380	11,597
Total (MMcfe)	67,384	33,407	16,502
Average net production (MMcfe/d)	184.6	91.5	45.1

Other North Louisiana

We own and operate approximately 49,198 gross (44,291 net) acres as of December 31, 2014 in our Other North Louisiana region. For the year ended December 31, 2014, our average net daily production from our Other North Louisiana properties was 11 MMcfe/d, of which 75% was natural gas. See "Recent Developments" above for further information regarding the February 23, 2015 Property Swap. Following the Property Swap, we own and operate approximately 25,541 gross (16,540 net) acres in our Other North Louisiana region.

East Texas

We owned and operated approximately 54,237 gross (42,844 net) acres as of December 31, 2014 in Texas, where we were producing primarily from the Cotton Valley, Travis Peak and Bossier formations and targeting the Cotton Valley formation for future development. As of December 31, 2014, we had approximately 39 gross proved identified horizontal drilling locations to which we have attributed proved undeveloped reserves. For the year ended December 31, 2014, our average net daily production from our East Texas properties was 26 MMcfe/d, of which 75% was natural gas. Within our East Texas properties, on a proved reserves basis, we operate approximately 98% of our existing properties as of December 31, 2014. See "Recent Developments" above for further information regarding the February 23, 2015 Property Swap. Following the Property Swap, we no longer own or operate oil and natural gas properties in East Texas.

Rockies

We own approximately 158,515 gross (62,562 net) acres as of December 31, 2014 in our Rockies region. For the year ended December 31, 2014 our average net daily production from this region was 5 MMcfe/d. As of December 31, 2014, we had approximately 1 gross identified vertical drilling location in the Tepee Field in our Rockies properties.

Reserves

Our estimates of proved reserves were prepared by our internal reserve engineers and audited by Netherland, Sewell & Associates, Inc. ("NSAI"). As of December 31, 2014, we had 1,632 Bcfe of estimated proved reserves. As of this date, our proved reserves were 72% gas and 28% NGLs and oil. The following table provides summary information regarding our estimated proved reserves data and our average net daily production by area based on our reserve report as of December 31, 2014.

Region	Proved Total (Bcfe)	% Gas	% Developed	Average Net Daily Production (MMcfe/d)
Terryville Complex	1,347	72 %	35 %	185

Other North Louisiana	50	86 %	43 %	11
East Texas	229	73 %	21 %	26
Rockies	6	95 %	78 %	5
Total	1,632	72 %	33 %	227

Business Strategies

Our primary objective is to build shareholder value through growth in reserves, production and cash flows by developing and expanding our significant portfolio of drilling locations. To achieve our objective, we intend to execute the following business strategies:

Grow production, reserves and cash flow through the development of our extensive drilling inventory. We believe our extensive inventory of low-risk drilling locations, combined with our operating expertise, will enable us to continue to deliver production, reserve and cash flow growth and create shareholder value. We believe that the risk and uncertainty associated with our core acreage positions in the Terryville Complex has been largely reduced through our development activity, and because those positions are in areas with extensive drilling and production history. With 6 rigs running in the Terryville Complex as of December 31, 2014, we are one of the most active drillers in the Cotton Valley formation. We believe multiple vertically stacked producing horizons in the Terryville Complex can be developed using horizontal drilling techniques, thus enhancing the economics of this field.

Enhance returns through prudent capital allocation and continued improvements in operational and capital efficiencies. We continually monitor and adjust our drilling program with the objective of achieving the highest total returns on our portfolio of drilling opportunities. We believe we will achieve this objective by (i) minimizing the capital costs of drilling and completing horizontal wells through knowledge of the target formations, (ii) maximizing well production and recoveries by optimizing lateral length, the number of frac stages, perforation intervals and the type of fracture stimulation employed, (iii) targeting specific zones within our leasehold position to maximize our hydrocarbon mix based on the existing commodity price environment and (iv) minimizing operating costs through efficient well management.

Exploit additional development opportunities on current acreage. Our existing asset base provides numerous opportunities for our highly experienced technical team to create shareholder value by increasing our inventory beyond our currently identified drilling locations and ultimately by growing our estimated proved reserves. In the Terryville Complex, we are currently targeting multiple stacked horizons.

Maintain a disciplined, growth oriented financial strategy. We intend to fund our growth primarily with internally generated cash flows from operations and borrowings under our revolving credit facility while maintaining ample liquidity and access to the capital markets. Furthermore, we plan to hedge a significant portion of our expected production to reduce our exposure to downside commodity price fluctuations and enable us to protect our cash flows and maintain our liquidity to fund our drilling program. Since approximately 60% of our acreage in the Terryville Complex was held by production as of December 31, 2014 and no significant drilling commitments are needed to hold our remaining acreage in the near term, we are able to allocate capital among projects in a manner that optimizes both costs and returns, resulting in a highly efficient drilling program.

Make opportunistic acquisitions that meet our strategic and financial objectives. We will seek to acquire oil and gas properties that we believe complement our existing properties in our core areas of operation. In addition to our focus on the Terryville Complex, we expect to pursue other properties that provide opportunities for the addition of reserves and production through a combination of exploitation, development, high-potential exploration and control of operations. We follow a technology driven strategy to establish large, contiguous leasehold positions in the core of prolific basins and opportunistically add to those positions through bolt-on acquisitions over time. We entered into the Terryville Complex through strategic acquisitions and grassroots leasing efforts. We will continue to identify and opportunistically acquire additional acreage and producing assets to complement our multi-year drilling inventory.

Competitive Strengths

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

Large, concentrated position in one of North America’s leading plays. As of December 31, 2014, we owned approximately 73,737 gross (61,157 net) acres in the Terryville Complex in Lincoln Parish, which we believe to be one of North America’s most prolific liquids-rich natural gas fields, characterized by consistent and predictable geology and multiple stacked pay formations confirmed by extensive vertical well control. During 2014, we have brought 31 wells online within our four primary target zones with average gross 30-day initial production rates of 20.2 MMcfe/d. Approximately 60% of our acreage in the Terryville Complex was held by production at December 31, 2014.

De-risked acreage position with multi-year inventory of liquids-rich drilling opportunities. As of December 31, 2014, we had a drilling inventory consisting of approximately 180 horizontal gross proved undeveloped locations, which includes 141 horizontal gross proved undeveloped locations in the Terryville Complex. The majority of our drilling activity has been and will continue to be focused in the Terryville Complex, where we produce liquids-rich natural gas from the overpressured Cotton Valley formation. We have used subsurface data from our vertical wells coupled with 3-D seismic data to identify and prioritize our inventory based on returns. This liquids-rich gas formation allows for NGL processing that, when coupled with the condensate produced, results in strong well economics. For the year ended December 31, 2014, 58% of our revenues were attributable to natural gas, 21% to NGLs and 21% to oil.

Significant operational control with low cost operations. On a proved reserves basis, we operate 99.6% of our properties and have operational control of all of our drilling inventory in the Terryville Complex. We believe maintaining operational control will enable us to enhance returns by implementing more efficient and cost effective operating practices, through the selection of economic drilling locations, opportunistic timing of development, continuous improvement of drilling, completion and stimulation techniques and development on multi-well pads. As a result of the contiguous nature of our leasehold in the Terryville Complex, its geologic continuity and cross unit lateral pooling, we are able to drill consistently long laterals, averaging over 5,800 lateral feet in 2014, which helps us to reduce costs on a per-lateral foot basis and increase our returns. Operating in mature basins in North Louisiana allows us to take advantage of the available and extensive midstream infrastructure and accelerate our development plan without encountering significant constraints in either takeaway or processing capacity. Our operational control allows us to focus on operating efficiency, which has resulted in our lease operating costs declining 40% from $0.53 per Mcfe for the year ended December 31, 2013 to $0.32 per Mcfe for the year ended December 31, 2014.

Proven and incentivized executive and technical team. We believe our management and technical teams are one of our principal competitive strengths due to our team's significant industry experience and long history of working together in the identification, execution and integration of acquisitions, cost efficient management of profitable, large scale drilling programs and a focus on rates of return. Additionally, our technical team has substantial expertise in advanced drilling and completion technologies and decades of expertise in operating in the North Louisiana and East Texas regions. The members of our management team collectively have an average of 23 years of experience in the oil and natural gas industry. John A. Weinzierl, our Chief Executive Officer, has 25 years of oil and natural gas industry experience as a petroleum engineer, a strong commercial background and extensive experience acquiring and managing oil and natural gas properties. Our management team has a significant economic interest in us directly and through its equity interests in our controlling stockholder, MRD Holdco. We believe our management team is motivated to deliver high returns, create shareholder value and maintain safe and reliable operations.

Our relationship with MEMP. We own a 0.1% general partner interest in MEMP through our ownership of its general partner, which owns 50% of MEMP's incentive distribution rights. MEMP's objective as a master limited partnership is to generate stable cash flows, allowing it to make quarterly distributions to its limited partners and, over time, to increase those quarterly distributions. As a result of its familiarity with our management team and our asset base and our track record of prior "drop-down" transactions, we believe that MEMP is a natural purchaser of properties from us that meet its acquisition criteria. We believe this mutually beneficial relationship enhances MEMP's ability to generate consistent returns on its oil and natural gas properties, provides us with a growing source of cash flow from our partnership interests in MEMP and allows us to monetize producing non-core properties. Since MEMP's initial public offering, we have consummated "dropdown" transactions with MEMP totaling approximately $469 million, including the February 2015 Property Swap. In addition, we may have the opportunity to work jointly with MEMP to pursue certain acquisitions of oil and natural gas properties that may not otherwise be attractive acquisition candidates for either of us individually. While we believe that MEMP would be a preferred acquirer of our mature, non-core assets, we are under no obligation to offer to sell, and it is under no obligation to offer to buy, any of our properties.

Financial strength and flexibility. We intend to continue to fund our organic growth with internally generated cash flows from operations and borrowings under our revolving credit facility while maintaining ample liquidity for opportunistic acquisitions. We will continue to maintain a disciplined approach to spending whereby we allocate capital in order to optimize returns and create shareholder value. We seek to protect these future cash flows and liquidity levels by maintaining a multi-year rolling hedge program. As of December 31, 2014, our total liquidity, consisting of cash on hand and available borrowing capacity under our revolving credit facility, was approximately $547.0 million.

Our Equity Owners

Our principal stockholder is MRD Holdco, which is controlled by the Funds, which are three of the private equity funds managed by NGP. MRD Holdco owns approximately 38% of our common stock. Pursuant to a voting agreement, MRD Holdco also has the right to direct the vote of an additional approximately 17% of our common stock owned by certain former management members of WildHorse Resources. The Funds also collectively indirectly own 50% of MEMP's incentive distribution rights, and MRD Holdco owns 5,360,912 common units of MEMP, representing an approximate 6.0% limited partner interest in MEMP.

Upon the closing of our initial public offering, we entered into a services agreement with WildHorse Resources and WildHorse Resources Management Company, LLC ("WHR Management Company") pursuant to which WHR Management Company agreed to provide operating and administrative services to us relating to the Terryville Complex. In exchange for such services, we paid a monthly management fee to WHR Management Company of approximately $1.0 million excluding third party COPAS income credits. In 2014, we paid approximately $6.2 million in aggregate to WHR Management Company in exchange for its services under the services agreement.

The services agreement was terminated effective March 1, 2015. WHR Management Company is a subsidiary of WildHorse Resources II, LLC, an affiliate of the Company. NGP and certain former management members of WildHorse Resources own WildHorse Resources II, LLC.

Founded in 1988, NGP is a family of private equity investment funds organized to make investments in the energy and natural resources sectors. NGP is part of the investment platform of NGP Energy Capital Management, a premier investment franchise in the natural resources industry with $16.5 billion in cumulative committed capital under management since inception.

Relationship with Memorial Production Partners LP

Through our ownership of its general partner, we control MEMP, a publicly traded limited partnership, and own 50% of MEMP's incentive distribution rights.

MEMP is engaged in the acquisition, exploitation, development and production of oil and natural gas properties in the United States, with assets consisting primarily of producing oil and natural gas properties that are located in Texas, Louisiana, Colorado, Wyoming, New Mexico and offshore Southern California. MEMP is focused on generating stable cash flows, to allow MEMP to make quarterly cash distributions to its unitholders and, over time, to increase those quarterly cash distributions. Most of MEMP's properties are located in large, mature oil and natural gas reservoirs with well-known geologic characteristics and long-lived, predictable production profiles and modest capital requirements. As of December 31, 2014:

- MEMP's total estimated proved reserves were approximately 1,454 Bcfe, of which approximately 38% were natural gas and 63% were classified as proved developed reserves; and
- MEMP produced from 3,424 gross (1,998 net) producing wells across its properties, with an average working interest of 58%.

In accordance with MEMP's limited partnership agreement, incentive distribution rights represent the right to receive an increasing percentage of quarterly distributions of MEMP's available cash from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. The minimum quarterly distribution is $0.4750 ($1.90 on an annualized basis) per unit. MEMP GP owns 50% of MEMP's incentive distribution rights, which are freely transferable under the MEMP limited partnership agreement. We own 100% of the voting and economic interests in MEMP GP.

Following the subordination period under MEMP's limited partnership agreement, which ended on February 13, 2015, MEMP is required to make distributions of available cash from operating surplus for any quarter in the following manner:

- first, 99.9% to all unitholders, pro rata, and 0.1% to MEMP GP, until each unitholder receives a total of $0.54625 per unit for that quarter;
- second, 85.0% to all unitholders, pro rata, 0.1% to MEMP GP, and 14.9% to the holders of the incentive distribution rights (50% of which are owned by MEMP GP), until each unitholder receives a total of $0.59375 per unit for that quarter; and
- thereafter, 75.0% to all unitholders, pro rata, 0.1% to MEMP GP, and 24.9% to the holders of the incentive distribution rights (50% of which are owned by MEMP GP).

Since December 2011, MEMP has increased its quarterly cash distribution from $0.4750 ($1.90 on an annualized basis) per unit to $0.5500 ($2.20 on an annualized basis) per unit, which is its most recently announced distribution rate. We anticipate receiving approximately $0.3 million from our partnership interests in MEMP in 2015 assuming no changes to MEMP's outstanding common units or its last declared cash distribution of $0.55 per unit.

We provide management, administrative, and operations personnel to MEMP under an omnibus agreement. Pursuant to that omnibus agreement, MEMP is required to reimburse us for all expenses incurred by us (or payments made on MEMP's behalf) in conjunction with our provision of general and administrative services to MEMP, including its public company expenses and an allocated portion of the salary and benefits of the executive officers of MEMP's general partner and our other employees who perform services for MEMP or on MEMP's behalf.

We view our relationship with MEMP as a part of our strategic alternatives, and we believe that MEMP will be incentivized to acquire additional suitable assets from us and to pursue acquisitions jointly with us in the future. However, MEMP will regularly evaluate acquisitions and may elect to acquire properties in the future without offering us the opportunity to participate in those transactions. MEMP is free to act in a manner that is beneficial to its interests without regard to ours, which may include electing not to acquire additional assets from us. Although we believe MEMP will desire to acquire properties from us for purchase, MEMP will not have any obligation to acquire properties from us. If MEMP chooses not to acquire properties from us, then our ability to monetize our proved developed properties may be impaired, which could adversely affect our cash flow and net income.

Our Oil and Natural Gas Data

Preparation of Reserve Estimates

Oil and natural gas reserve engineering is inherently a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured exactly. The accuracy of any reserve estimate is a function of the quality of available data and engineering and geological interpretation and judgment. Accordingly, reserve estimates may vary from the quantities of oil and natural gas that are ultimately recovered. For a discussion of risks associated with reserve estimates, please read “Item 1A. Risk Factors—Risks Related to Our Business—Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.”

Evaluation and Review of Estimated Reserves. We engaged NSAI to audit our reserves estimates for all of our proved, probable and possible reserves (by volume) at December 31, 2014. MEMP engaged NSAI and Ryder Scott Company, L.P. (“Ryder Scott”) to audit MEMP’s reserves estimates for all of MEMP’s proved reserves (by volume) at December 31, 2014. The technical persons responsible for auditing our reserve estimates and MEMP’s 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.

We maintain an internal staff of petroleum engineers and geoscience professionals who work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of the data used to calculate our estimated reserves and MEMP’s proved reserves. Our technical team meets regularly with NSAI and Ryder Scott reserve engineers to review properties and discuss the assumptions and methods used in the reserve estimation process. We provide historical information to NSAI and Ryder Scott for our properties and MEMP’s properties, such as ownership interest, oil and natural gas production, well test data, commodity prices and operating and development costs.

Internal Engineers. John D. Williams is the technical person at the Company primarily responsible to liaison with and provide oversight of our third-party reserve engineers, NSAI and Ryder Scott, which audited the reserve report for our properties and MEMP’s properties. Mr. Williams has been practicing petroleum engineering at the Company since March 2012. Mr. Williams is a Registered Professional Engineer in the State of Texas with over 18 years of experience in the estimation and evaluation of reserves. From April 2005 to March 2012, he held various positions at Southwestern Energy Company, most recently as Reservoir Engineering Manager. From August 1998 to April 2005, he served in various capacities at Ryder Scott Company, which culminated in his serving as Vice President. Mr. Williams is a graduate of the University of Texas at Austin with a B.S. in petroleum engineering and with a M.S. in petroleum engineering.

Ryder Scott Company, L.P. Ryder Scott is an independent oil and natural gas consulting firm. No director, officer, or key employee of Ryder Scott has any financial ownership in us, the Funds, or any of their respective affiliates. Ryder Scott’s compensation for the required investigations and preparation of its report is not contingent upon the results obtained and reported. Ryder Scott has not performed other work for us, the Funds, or any of their respective affiliates that would affect its objectivity. The audit of estimates of MEMP’s proved reserves presented in the Ryder Scott report were overseen by Miles Robert Palke.

Miles Palke has been practicing consulting petroleum engineering at Ryder Scott since 2010. Mr. Palke is a Licensed Professional Engineer in the State of Texas and has over 18 years of practical experience in petroleum engineering, with over 18 years of experience in the estimation and evaluation of reserves. He graduated from Texas A&M with a B.S. in petroleum engineering and from Stanford University with a M.S. in petroleum engineering.

Mr. Palke meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Netherland, Sewell & Associates, Inc. NSAI is an independent oil and natural gas consulting firm. No director, officer, or key employee of NSAI has any financial ownership in us, the Funds, or any of their respective affiliates. NSAI's compensation for the required investigations and preparation of its report is not contingent upon the results obtained and reported. NSAI has not performed other work for us, the Funds, or any of their respective affiliates that would affect its objectivity. The audit of estimates of our reserves and MEMP's proved reserves presented in the NSAI reports were overseen by Mr. Justin S. Hamilton; Mr. David E. Nice; Mr. Richard B. Talley, Jr.; Mr. Philip S. (Scott) Frost; Mr. Eric J. Stevens; Mr. Craig H. Adams; Mr. Nathan C. Shahan; and Mr. William J. Knights.

Justin Hamilton has been practicing consulting petroleum engineering at NSAI since 2004. Mr. Hamilton is a Licensed Professional Engineer in the State of Texas (License No. 104999) and has over 14 years of practical experience in petroleum engineering, with over 14 years of experience in the estimation and evaluation of reserves. He graduated from Brigham Young University in 2000 with a B.S. in mechanical engineering and from the University of Texas in 2007 with an M.B.A.

David Nice has been practicing consulting petroleum geology at NSAI since 1998. Mr. Nice is a Licensed Professional Geoscientist in the State of Texas (License No. 346) and has over 29 years of practical experience in petroleum geosciences, with over 16 years of experience in the estimation and evaluation of reserves. He graduated from University of Wyoming in 1982 with a B.S. in geology and in 1985 with an M.S. in geology.

Richard Talley has been practicing consulting petroleum engineering at NSAI since 2004. Mr. Talley is a Licensed Professional Engineer in the State of Texas (License No. 102425) and in the State of Louisiana (License No. 36998) and has over 16 years of practical experience in petroleum engineering, with over 10 years of experience in the estimation and evaluation of reserves. He graduated from University of Oklahoma in 1998 with a B.S. in mechanical engineering and from Tulane University in 2001 with an M.B.A.

Scott Frost has been practicing consulting petroleum engineering at NSAI since 1984. Mr. Frost is a Licensed Professional Engineer in the State of Texas (License No. 88738) and has over 30 years of practical experience in petroleum engineering, with over 30 years of experience in the estimation and evaluation of reserves. He graduated from Vanderbilt University in 1979 with a B.E. in mechanical engineering and from Tulane University in 1984 with an M.B.A.

Eric Stevens has been practicing consulting petroleum engineering at NSAI since 2007. Mr. Stevens is a Licensed Professional Engineer in the State of Texas (License No. 102415) and has over 12 years of practical experience in petroleum engineering, with over 12 years of experience in the estimation and evaluation of reserves. He graduated from Brigham Young University in 2002 with a B.S. in mechanical engineering.

Craig Adams has been practicing consulting petroleum engineering at NSAI since 1997. Mr. Adams is a Licensed Professional Engineer in the State of Texas (License No. 68137) and has over 30 years of practical experience in petroleum engineering, with over 18 years of experience in the estimation and evaluation of reserves. He graduated from Texas Tech University in 1985 with a B.S. in petroleum engineering.

Nathan Shahan has been practicing consulting petroleum engineering at NSAI since 2007. Mr. Shahan is a Licensed Professional Engineer in the State of Texas (License No. 102389) and has over 13 years of practical experience in petroleum engineering, with over 8 years of experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 2002 with a B.S. in petroleum engineering and in 2007 with a M.E. in petroleum engineering.

William Knights has been practicing consulting petroleum geology at NSAI since 1991. Mr. Knights is a Licensed Professional Geoscientist in the State of Texas (License No. 1532) and has over 30 years of practical experience in petroleum geosciences, with over 30 years of experience in the estimation and evaluation of reserves. He graduated from Texas Christian University in 1981 with a B.S. in geology and in 1984 with a M.S. in geology.

All eight technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; all eight are proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Estimation of Proved Reserves. Under SEC rules, proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. If deterministic methods are used, the SEC has defined reasonable certainty for proved reserves as a "high degree of confidence that the quantities will be recovered." All of our proved reserves and MEMP's proved reserves as of December 31, 2014 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and natural gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions 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: (1) production performance-based methods; (2) material balance-based methods; (3) volumetric-based methods; and (4) 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 proved developed producing 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 proved undeveloped reserves 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, management 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.

Estimation of Probable and Possible Reserves. Estimates of probable reserves are inherently imprecise. When producing an estimate of the amount of oil and natural gas that is recoverable from a particular reservoir, an estimated quantity of probable reserves is an estimate of those additional reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Estimates of probable reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors.

When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates. Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir. Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

Estimates of possible reserves are also inherently imprecise. When producing an estimate of the amount of oil and natural gas that is recoverable from a particular reservoir, an estimated quantity of possible reserves is an estimate that might be achieved, but only under more favorable circumstances than are likely. Estimates of possible reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors.

When deterministic methods are used, the total quantities ultimately recovered from a project have a low probability of exceeding proved plus probable plus possible reserves. When probabilistic methods are used, there should be at least a 10% probability that the total quantities ultimately recovered will equal or exceed the proved plus probable plus possible reserves estimates. Possible reserves may be assigned to areas of a reservoir adjacent to probable reserve where data control and interpretations of available data are progressively less certain. Frequently, this will be in areas where geoscience and engineering data are unable to define clearly the area and vertical limits of commercial production from the reservoir. Possible reserves also include incremental quantities associated with a greater percentage of recovery of the hydrocarbons in place than the recovery quantities assumed for probable reserves.

Possible reserves may be assigned where geoscience and engineering data identify directly adjacent portions of a reservoir within the same accumulation that may be separated from proved areas by faults with displacement less than formation thickness or other geological discontinuities and that have not been penetrated by a wellbore, and the registrant believes that such adjacent portions are in communication with the known (proved) reservoir. Possible reserves may be assigned to areas that are structurally higher or lower than the proved area if these areas are in communication with the proved reservoir.

Estimated Proved Reserves

The table below identifies our proved reserves as of December 31, 2014 per our reserve report for our three areas:

	Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total (MMcfe)
Proved Developed				
Terryville Complex	3,456	332,483	17,919	460,732
Other North Louisiana	223	18,262	273	21,240
East Texas	197	36,850	1,721	48,358
Rockies	28	4,585	11	4,821
Total Proved Developed	3,904	392,180	19,924	535,151
Proved Undeveloped				
Terryville Complex	7,873	632,367	34,453	886,322
Other North Louisiana	327	24,303	377	28,527
East Texas	491	130,739	7,835	180,691
Rockies	8	1,340	—	1,388
Total Proved Undeveloped	8,699	788,749	42,665	1,096,928
Total Proved				
Terryville Complex	11,329	964,850	52,372	1,347,054
Other North Louisiana	550	42,565	650	49,767
East Texas	688	167,589	9,556	229,049
Rockies	36	5,925	11	6,209
Total Proved Reserves	12,603	1,180,929	62,589	1,632,079

Proved Undeveloped Reserves

As of December 31, 2014, we had 1,097 Bcfe of proved undeveloped reserves, comprised of 9 MMBbls of oil, 789 Bcf of natural gas and 43 MMBbls of NGLs. None of our PUDs as of December 31, 2014 are scheduled to be developed on a date more than five years from the date the reserves were initially booked as PUDs. PUDs will be converted from undeveloped to developed as the applicable wells begin production.

Changes in PUDs that occurred during 2014 were due to:

- Reclassifications of 72 Bcfe into proved developed reserves for implementation of drilling projects;
- Increase of 141 Bcfe of additions from the Terryville Complex due to proving up additional drilling locations; and
- Revisions of 270 Bcfe, primarily as a result of performance, in East Texas and the Terryville Complex.

During the year ended December 31, 2014, we spent $92.1 million to convert PUDs to proved developed reserves. As of December 31, 2014 per our reserve report, future development costs relating to the development of PUDs for the years 2015, 2016, 2017, 2018, and 2019 are estimated at approximately $365 million, $464 million, $421 million,

$146 million and $2 million, respectively, to capture the balance of drilling the PUD reserves within a five-year timeframe. Approximately $1.2 billion of the future development costs over the next five years are related to development of PUD reserves in the Terryville Complex. As we continue to develop our properties and have more well production and completion data, we believe we will continue to realize cost savings and experience lower relative drilling and completion costs as we convert PUDs into proved developed reserves in the upcoming years. All of our PUD locations are scheduled to be drilled prior to the end of December 31, 2019. Based on our current expectations of our cash flows, we believe that we can fund the drilling of our current PUD inventory and our expansions in the next five years from our cash flow from operations and borrowings under our revolving credit facility.

Reconciliation of PV-10 to Standardized Measure

PV-10 is a non-GAAP financial measure and differs from the Standardized Measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the Standardized Measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated net proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies without regard to the specific tax characteristics of such entities. We use this measure when assessing the potential return on investment related to our oil and natural gas properties. PV-10, however, is not a substitute for the Standardized Measure of discounted future net cash flows. Our PV-10 measure and the Standardized Measure of discounted future net cash flows do not purport to represent the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of PV-10 of our proved reserves to the Standardized Measure of discounted future net cash flows at December 31, 2014, 2013 and 2012:

	For the Year Ending December 31,		
	2014	2013	2012
	(In thousands)		
PV-10	$3,021,348	$1,468,952	$1,320,595
Less: present value of future income taxes discounted at 10%	1,058,814	—	—
Standardized measure	$1,962,534	$1,468,952	$1,320,595

Prior to our initial public offering, we were not subject to federal income tax; hence no income taxes were applied to reserve values in previous years.

Production, Revenue and Price History

The following tables set forth information regarding our production, revenues and realized prices and production costs for the years ended December 31, 2014, 2013, and 2012, respectively:

	For the Year Ended December 31, 2014				
	Terryville Complex	Other North Louisiana	East Texas	Rockies	Total
Production Volumes:					
Oil (MBbls)	716	95	43	97	951
NGLs (MBbls)	1,763	72	355	30	2,220
Natural Gas (MMcf)	52,512	2,892	7,227	1,170	63,801
Total (MMcfe)	67,384	3,880	9,616	1,935	82,815
Average net production (MMcfe/d)	184.6	10.7	26.3	5.3	226.9
Average sales price:					
Oil (per Bbl)	$89.25	$ 93.48	$88.96	$ 88.27	$89.54
NGL (per Bbl)	41.52	32.30	26.12	32.81	38.62
Natural Gas (Mcf)	3.61	4.09	3.95	3.49	3.67
Total (Mcfe)	$4.85	$ 5.91	$4.33	$ 7.06	$4.89
Average unit costs per Mcfe:					
Lease operating expense	$0.19	$ 1.03	$0.95	$ 0.74	$0.32

	For the Year Ended December 31, 2013				
	Terryville Complex	Other North Louisiana	East Texas	Rockies	Total
Production Volumes:					
Oil (MBbls)	386	89	165	25	665
NGLs (MBbls)	1,118	125	177	37	1,457
Natural Gas (MMcf)	24,380	3,018	6,249	445	34,092
Total (MMcfe)	33,407	4,298	8,297	817	46,819
Average net production (MMcfe/d)	91.5	11.8	22.8	2.2	128.3
Average sales price:					
Oil (per Bbl)	$100.18	$ 102.27	$102.06	$95.78	$100.76
NGL (per Bbl)	38.51	30.35	31.33	40.68	36.99
Natural Gas (Mcf)	3.07	3.36	3.79	2.91	3.22
Total (Mcfe)	$4.69	$ 5.34	$5.54	$6.39	$4.93
Average unit costs per Mcfe:					
Lease operating expense	$0.23	$ 1.16	$1.24	$1.91	$0.53

	For the Year Ended December 31, 2012				
	Terryville Complex	Other North Louisiana	East Texas	Rockies	Total
Production Volumes:					
Oil (MBbls)	212	61	67	29	369
NGLs (MBbls)	605	97	85	111	898
Natural Gas (MMcf)	11,597	2,431	8,917	1,185	24,130
Total (MMcfe)	16,502	3,372	9,832	2,025	31,731
Average net production (MMcfe/d)	45.1	9.2	26.9	5.5	86.7
Average sales price:					
Oil (per Bbl)	$94.98	$ 98.59	$97.98	$ 88.05	$95.56
NGL (per Bbl)	41.50	34.40	39.08	43.71	40.78
Natural Gas (Mcf)	2.53	2.53	3.13	2.32	2.74
Total (Mcfe)	$4.53	$ 4.57	$3.84	$ 5.02	$4.35
Average unit costs per Mcfe:					
Lease operating expense	$0.46	$ 1.34	$0.99	$ 1.24	$0.77

Productive Wells

The following table sets forth information regarding productive wells in each of our areas at December 31, 2014.

	Gross	Net	Operated
Terryville Complex	339	271	320
Other North Louisiana	246	138	161
East Texas	144	98	102
Rockies	59	5	4
Total	788	512	587

Acreage

The following table sets forth information regarding the developed and undeveloped acreage in which we own an interest as of December 31, 2014.

	Developed Acreage		Undeveloped Acreage		Total Acreage			
	Gross	Net	Gross	Net	Gross	Net	Net HBP	WI
Terryville Complex	47,514	36,604	26,223	24,553	73,737	61,157	60 %	83%
Other North Louisiana	47,774	42,867	1,424	1,424	49,198	44,291	97 %	90%
East Texas	37,109	30,335	17,128	12,509	54,237	42,844	71 %	79%
Rockies	9,466	4,251	149,049	58,311	158,515	62,562	7 %	39%
Total	141,863	114,057	193,824	96,797	335,687	210,854	54 %	63%

Undeveloped Acreage Expirations

The following table sets forth the gross and net undeveloped acreage in our core operating areas as of December 31, 2014 that will expire over the next three 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. Of the acreage set to expire in the Terryville Complex for 2015, approximately 90% of the acreage can be retained by either establishing production or through lease extensions. There are no proved reserves attributable to our expiring acreage.

	2015		2016		2017	
	Gross	Net	Gross	Net	Gross	Net
Terryville Complex	10,346	9,212	9,113	6,545	3,837	2,156
Other North Louisiana	—	—	324	324	1,100	1,100
East Texas	1,917	801	323	116	1,445	1,184
Rockies	15,564	8,878	27,582	17,455	17,787	9,783
Total	27,827	18,891	37,342	24,440	24,169	14,223

Drilling Activity

The following table summarizes our drilling activity for the years ended December 31, 2014, 2013, 2012. Gross wells reflect the sum of all wells in which we own an interest. Net wells reflect the sum of our working interests in gross wells. At December 31, 2014, 27 gross (22.9 net) wells were in various stages of drilling or completion.

	For the Year Ending December 31,					
	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	22.0	18.8	22.0	13.3	11.0	10.2
Dry	—	—	—	—	—	—
Total development wells	22.0	18.8	22.0	13.3	11.0	10.2
Exploratory wells:						
Productive	16.0	14.4	9.0	8.0	7.0	5.6
Dry	—	—	—	—	—	—
Total exploratory wells	16.0	14.4	9.0	8.0	7.0	5.6
Total wells drilled	38.0	33.2	31.0	21.3	18.0	15.8

Delivery Commitments

The Company has no commitments to deliver a fixed and determinable quantity of our oil or natural gas production to customers in the near future under our existing contracts.

We have entered into gas processing agreements associated with our Terryville Complex production with both related and third party midstream service providers that have volumetric requirements. Information regarding our delivery commitments under these contracts is contained in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Contractual Obligations" and Notes 13 and 16 under "Item 8. Financial Statements and Supplementary Data," both contained herein.

MEMP

The following table summarizes information about MEMP's proved oil and natural gas reserves by geographic region and its average net production as of December 31, 2014.

	Estimated Total Reserves					
	Total (Bcfe)	% Gas	% Oil & NGLs	% Developed	Standardized Measure (in millions)(1)	Average Net Daily Production (MMcfe/d)
East Texas/North Louisiana	545	69 %	31 %	62 %	$ 684	127.0
Rockies	557	9 %	91 %	61 %	1,236	44.4
South Texas	190	68 %	32 %	79 %	321	32.8
Permian Basin	87	4 %	96 %	51 %	175	11.7
California	75	0 %	100 %	69 %	344	11.9
Total	1,454	38 %	62 %	63 %	$ 2,760	227.8

(1) Standardized measure is calculated in accordance with Accounting Standards Codification, or ASC, Topic 932, Extractive Activities – Oil and Gas. Because MEMP is a limited partnership, it is generally not subject to federal or

state income taxes and thus makes no provision for federal or state income taxes in the calculation of its standardized measure. Standardized measure does not give effect to commodity derivative contracts.

Estimated Proved Reserves

The following table presents the estimated net proved oil and natural gas reserves attributable to MEMP's properties as of December 31, 2014, based on MEMP's audited reserve report.

	Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total (MMcfe)
Estimated Proved Reserves				
Total Proved Developed	54,526	380,397	35,539	920,783
Total Proved Undeveloped	45,044	179,230	13,939	533,128
Total Proved Reserves	99,570	559,627	49,478	1,453,911

Development of Proved Undeveloped Reserves

As of December 31, 2014, MEMP had 533 Bcfe of proved undeveloped reserves, comprised of 45 MBbls of oil, 179 MMcf of natural gas and 14 MBbls of NGLs. None of MEMP's PUDs as of December 31, 2014 are scheduled to be developed on a date more than five years from the date the reserves were initially booked as PUDs. PUDs will be converted from undeveloped to developed as the applicable wells begin production. During the fiscal year ended 2014, MEMP's proved undeveloped reserves increased 135 Bcfe, from 398 Bcfe to 533 Bcfe. MEMP made approximately $164.0 million of capital expenditures during the year ended December 31, 2014 to convert approximately 112 Bcfe of proved undeveloped reserves to proved developed reserves. This decrease of 112 Bcfe was offset by a 247 Bcfe increase in proved undeveloped reserves during the year ended December 31, 2014. Based on MEMP's current expectations of its cash flows, MEMP believes that it can fund the drilling of its current PUD inventory and its expansions in the next five years from its cash flow from operations and borrowings under its revolving credit facility.

Production, Revenue and Price History

The following tables summarize MEMP's average net production, average sales prices by product and average production costs and for the years ended December 31, 2014, 2013, and 2012, respectively:

	For the Year Ended December 31,		
	2014	2013	2012
Production Volumes:			
Oil (MBbls)	3,092	1,764	1,519
NGLs (MBbls)	2,143	1,632	745
Natural Gas (MMcf)	41,494	35,924	29,744
Total (MMcfe)	72,902	56,303	43,329
Average net production (MMcfe/d)	199.7	154.3	118.4
Average sales price:			
Oil (per Bbl)	$84.88	$96.98	$95.54
NGL (per Bbl)	30.20	31.38	36.78
Natural Gas (Mcf)	3.93	3.31	2.82
Total (Mcfe)	$6.72	$6.06	$5.90
Average unit costs per Mcfe:			
Lease operating expense	$1.85	$1.58	$1.85

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 facilities. Gross wells are the total number of producing wells in which MEMP owns an interest, and net wells are the sum of MEMP's fractional working interests owned in gross wells. The following table sets forth information relating to the productive wells in which MEMP owned a working interest as of December 31, 2014.

	Oil		Natural Gas	
	Gross	Net	Gross	Net
Operated (1)	766	710	1,444	1,098
Non-operated	263	26	951	164
Total	1,029	736	2,395	1,262

(1) Includes wells operated by the Company on MEMP's behalf.

Developed Acreage

Acreage related to royalty, overriding royalty and other similar interests is excluded from this summary. As of December 31, 2014, substantially all of MEMP's leasehold acreage was held by production. The following table sets forth information as of December 31, 2014 relating to MEMP's leasehold acreage.

	Developed Acreage (1)	
	Gross (2)	Net (3)
East Texas/North Louisiana	169,134	85,000
Rockies	137,824	69,691
South Texas	110,038	99,513
Permian Basin	37,766	35,756
Total	454,762	289,960

(1) Developed acres are acres spaced or assigned to productive wells or wells capable of production.
(2) A gross acre is an acre in which MEMP owns a working interest. The number of gross acres is the total number of acres in which MEMP owns a working interest.
(3) A net acre is deemed to exist when the sum of MEMP's 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.

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Undeveloped Acreage

The following table sets forth information as of December 31, 2014 relating to MEMP's undeveloped leasehold acreage.

	Undeveloped Acreage 1	
	Gross (1)	Net (2)
East Texas/North Louisiana	9,962	3,165
Rockies	88,820	52,072
South Texas	2,717	2,204
Permian Basin	11,867	11,804
Total	113,366	69,245

(1) A gross acre is an acre in which MEMP owns a working interest. The number of gross acres is the total number of acres in which MEMP owns a working interest.
(2) A net acre is deemed to exist when the sum of MEMP's 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.

Drilling Activities

MEMP's drilling activities consist entirely of development wells. The following table sets forth information with respect to wells drilled and completed by MEMP or its previous owners during the periods indicated. The information should not be considered indicative of future performance, nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found or economic value. At December 31, 2014, 12.0 gross (8.0 net) wells were in various stages of completion.

	For the Year Ending December 31,					
	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	102.0	57.3	45.0	32.6	38.0	24.4
Dry	7.0	1.9	—	—	1.0	1.0
Exploratory wells:						
Productive	—	—	—	—	—	—
Dry	—	—	—	—	—	—
Total wells:						
Productive	102.0	57.3	45.0	32.6	38.0	24.4
Dry	7.0	1.9	—	—	1.0	1.0
Total	109.0	59.2	45.0	32.6	39.0	25.4

For purposes of the table above, MEMP's previous owners refers collectively to (a) certain oil and natural gas properties that MEMP acquired from MRD LLC in April and May 2012 for periods after common control commenced through their respective acquisition dates; (b) Rise Energy Operating, LLC and its wholly-owned subsidiaries (except for Rise Energy Operating, Inc.) from February 3, 2009 (inception) through December 11, 2012; (c) certain oil and natural gas properties acquired from WHT Energy Partners ("WHT") (the "WHT Properties") from February 2, 2011 (inception) through March 2013; and (d) certain oil and natural gas properties acquired through equity and asset transactions on October 1, 2013 from both MRD LLC and certain affiliates of NGP that were a part of the Cinco Group acquisition.

Delivery Commitments

MEMP has no commitments to deliver a fixed and determinable quantity of its oil or natural gas production to customers in the near future under its existing contracts.

Marketing and Major Customers

We market the majority of production from properties we and MEMP operate for both our account and the account of the other working interest owners in our operated properties. We sell substantially all of our production to a variety of purchasers under short-term contracts (less than 12 months). Some production is committed to service and/or sales agreements for longer terms where market access mandates. In all circumstances, the sale of commodities is at prevailing market prices. We normally sell production to a relatively small number of customers, as is customary in the exploration, development and production business. During the year ended December 31, 2014, Energy Transfer Equity, L.P. and subsidiaries accounted for 73% of our revenues, while Phillips 66 and Sinclair Oil & Gas Company accounted for 13% and 12% of MEMP's revenues, respectively. If we were to lose any one of our customers, the loss could temporarily delay production and sale of a portion of our oil and natural gas in the related producing region. If we were to lose any single customer, we believe we could identify a substitute customer to purchase the impacted production volumes.

Title to Properties

We believe that we and MEMP have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, in the case of undeveloped properties, often cursory investigation of record title is made at the time of lease acquisition. Investigations are made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use or affect the value of the properties. Burdens on properties may include customary royalty interests, liens incident to operating agreements and for current taxes, obligations or duties under applicable laws, development obligations under natural gas leases, or net profits interests.

Oil and Natural Gas Leases

The typical oil and natural gas lease agreement covering our properties and MEMP's 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 12.5% to 25%, resulting in a net revenue interest to us generally ranging from 87.5% to 75%.

Seasonality

Demand for oil and natural gas generally decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. These seasonal anomalies can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations or MEMP's operations.

Competition

The oil and natural gas industry is intensely competitive, and we and MEMP compete with other companies in our industry that have greater resources than we do, especially in our focus areas. Many of these companies not only explore for and produce oil and natural gas, but also carry on 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 natural gas properties and exploratory locations or define, evaluate, bid for and purchase a greater number of properties and locations than our financial or human resources permit, and may be able to expend greater resources to attract and maintain industry personnel. 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 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 locations and producing oil and natural gas properties.

Hydraulic Fracturing

We and MEMP use hydraulic fracturing as a means to maximize the productivity of almost every well that we drill and complete. Hydraulic fracturing is a necessary part of the completion process because our properties are dependent upon our ability to effectively fracture the producing formations in order to produce at economic rates. Nearly all of our proved non-producing and proved undeveloped reserves associated with future drilling, recompletion, and refracture stimulation projects, or approximately 70% of our total estimated proved reserves as of December 31, 2014 and approximately 36% of MEMP's total estimated proved reserves as of December 31, 2014, require hydraulic fracturing.

We have and continue to follow applicable industry standard practices and legal requirements for groundwater protection in our and MEMP's operations which are subject to supervision by state and federal regulators (including the Bureau of Land Management on federal acreage). These protective measures include setting surface casing at a depth sufficient to protect fresh water zones as determined by regulatory agencies, and cementing the well to create a permanent isolating barrier between the casing pipe and surrounding geological formations. This aspect of well design essentially eliminates a pathway for the fracturing fluid to contact any aquifers during the hydraulic fracturing operations. For recompletions of existing wells, the production casing is pressure tested prior to perforating the new completion interval.

Injection rates and pressures are monitored instantaneously and in real time at the surface during our hydraulic fracturing operations. Pressure is monitored on both the injection string and the immediate annulus to the injection string. Hydraulic fracturing operations would be shut down immediately if an abrupt change occurred to the injection pressure or annular pressure.

Certain state regulations require disclosure of the components in the solutions used in hydraulic fracturing operations. Approximately 99% of the hydraulic fracturing fluids we use are made up of water and sand. The remainder of the constituents in the fracturing fluid are managed and used in accordance with applicable requirements.

Hydraulic fracture stimulation requires the use of a significant volume of water. Upon flowback of the water, we dispose of it in a way that minimizes the impact to nearby surface water by disposing into approved disposal or injection wells. We currently do not discharge water to the surface.

For information regarding existing and proposed governmental regulations regarding hydraulic fracturing and related environmental matters, please read "Item 1. Business—Regulation of Environmental and Occupational Health and Safety Matters—Hydraulic Fracturing."

Regulation of the Oil and Natural Gas Industry

Our and MEMP's 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 oil and natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, FERC, and the courts. We cannot predict when or whether any such proposals may become effective.

We believe we and MEMP 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. All of the states in which we and MEMP own and operate properties have regulations governing 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, 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. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. We own interests in properties located onshore in different

U.S. states. These states regulate 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 these states also govern a number of environmental and conservation matters, including the handling and disposing or discharge of waste materials, the size of drilling and spacing units or proration units and the density of wells that may be drilled, unitization and pooling of oil and natural gas properties and establishment of maximum rates of production from oil and natural gas wells. Some states have the power to prorate production due to the market demand for oil and natural gas. 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 Environmental and Occupational Health and Safety Matters

Our and MEMP's operations are subject to numerous stringent federal, state and local statutes and regulations governing the discharge of materials into the environment or otherwise relating to protection of the environment or occupational health and safety. Numerous governmental agencies, such as the U.S. Environmental Protection Agency ("EPA"), issue regulations, which often require difficult and costly compliance measures that carry substantial administrative, civil and criminal penalties and may result in injunctive obligations for failure to comply. These laws and regulations may, among other things, require the acquisition of a permit before drilling commences; restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines; govern the sourcing and disposal of water used in the drilling, completion and production process; restrict the way we handle or dispose of our wastes or of naturally occurring radioactive materials generated by our operations; 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 current or former operations such as plugging abandoned wells or closing earthen pits; result in the suspension or revocation of necessary permits, licenses and authorizations; require that additional pollution controls be installed; and impose substantial liabilities for pollution resulting from operations or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of production. The strict and joint and several liability nature of such laws and regulations could impose liability upon us regardless of fault. Public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. Changes in environmental laws and regulations occur frequently, and to the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business and prospects, as well as the oil and natural gas industry in general, could be materially adversely affected.

Hazardous Substance and Waste Handling

Our and MEMP's operations are subject to environmental laws and regulations relating to the management and release of hazardous substances, solid and hazardous wastes and petroleum hydrocarbons. These laws generally regulate the generation, storage, treatment, transportation and disposal of solid and hazardous waste and may impose strict and, in some cases, joint and several liability for the investigation and remediation of affected areas where hazardous substances may have been released or disposed. The Comprehensive Environmental Response, Compensation, and Liability Act, as amended, referred to as CERCLA or 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 deemed "responsible parties." These persons include current owners or operators of the site where a release of hazardous substances occurred, prior owners or operators that owned or operated the site at the time of the release or disposal of hazardous substances, and companies that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, these persons may be subject to strict and joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some instances, third parties to act in response to threats to the public health or the environment and to seek to recover the costs they incur from the responsible classes of persons. It is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment. Despite the "petroleum exclusion" of Section 101(14) of CERCLA, which currently encompasses natural gas, we may nonetheless handle hazardous substances within the meaning of CERCLA, or similar state statutes, in the course of our ordinary operations and, as a result, may be jointly and severally liable under CERCLA for all or part of the costs required to clean up sites at which these hazardous substances have been released into the environment. Also, comparable state statutes may not contain a similar exemption for petroleum. In addition, we may have liability for releases of hazardous substances at our properties by prior owners or operators or other third parties.

The Oil Pollution Act of 1990 (the "OPA") is the primary federal law imposing oil spill liability. The OPA contains numerous requirements relating to the prevention of and response to petroleum releases into waters of the United States, including the requirement that operators of offshore facilities and certain onshore facilities near or crossing waterways must maintain certain significant levels of financial assurance to cover potential environmental cleanup and restoration costs. Under the OPA, strict, joint and several liability may be imposed on "responsible parties" for all containment and cleanup costs and certain other damages arising from a release, including, but not limited to, the costs of responding to a release of oil to surface waters and natural resource damages, resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A "responsible party" includes the owner or operator of an onshore facility. The OPA establishes a liability limit for onshore facilities of $350 million per spill. These liability limits may not apply if: a spill is caused by a party's gross negligence or willful misconduct; the spill resulted from violation of a federal safety, construction or operating regulation; or a party fails to report a spill or to cooperate fully in a clean-up. We are also subject to analogous state statutes that impose liabilities with respect to oil spills.

We also generate solid wastes, including hazardous wastes, which are subject to the requirements of the Resource Conservation and Recovery Act (“RCRA”), as amended and comparable state statutes. Although RCRA regulates both solid and hazardous wastes, it imposes strict requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum production wastes are excluded from RCRA’s hazardous waste regulations. It is possible, however, that these wastes, which could include wastes currently generated during our operations, could be designated as “hazardous wastes” in the future and, therefore, be subject to more rigorous and costly disposal requirements. Indeed, legislation has been proposed from time to time in Congress to re-categorize certain oil and gas exploration and production wastes as “hazardous wastes.” Any such changes in the laws and regulations could have a material adverse effect on our capital expenditures and operating expenses.

It is possible that our oil and natural gas operations may require us to manage naturally occurring radioactive materials, or NORM. NORM is present in varying concentrations in sub-surface formations, including hydrocarbon reservoirs, and may become concentrated in scale, film and sludge in equipment that comes in contact with crude oil and natural gas production and processing streams. Some states have enacted regulations governing the handling, treatment, storage and disposal of NORM.

Administrative, civil and criminal penalties can be imposed for failure to comply with waste handling requirements. We believe that we and MEMP are in substantial compliance with the requirements of CERCLA, RCRA, OPA and related state and local laws and regulations, and that we hold all necessary and up-to-date permits, registrations and other authorizations required under such laws and regulations. Although we believe that the current costs of managing our wastes as they are presently classified are reflected in our budget, any legislative or regulatory reclassification of oil and natural gas exploration and production wastes could increase our costs to manage and dispose of such wastes.

Water and Other Waste Discharges and Spills

The Federal Water Pollution Control Act, as amended, also known as the Clean Water Act, the Safe Drinking Water Act (“SDWA”), the OPA and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other gas and oil wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers. The EPA has also adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain individual permits or coverage under general permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans, as well as for monitoring and sampling the storm water runoff from certain of our facilities. Some states also maintain groundwater protection programs that require permits for discharges or operations that may impact groundwater conditions. The underground injection of fluids is subject to permitting and other requirements under state laws and regulation. Obtaining permits has the potential to delay the development of oil and natural gas projects. These same regulatory programs also limit the total volume of water that can be discharged, hence limiting the rate of development, and require us to incur compliance costs.

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 the underground injection of fluids 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 and MEMP maintain all required discharge permits necessary to conduct our operations, and we believe we and MEMP are in substantial compliance with their terms.

Hydraulic Fracturing

We and MEMP use hydraulic fracturing extensively in our operations. Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of natural gas and/or oil from low permeability subsurface rock formations. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore. While hydraulic fracturing has historically been regulated by state oil and natural gas commissions, the practice has become increasingly controversial in certain parts of the country, resulting in increased scrutiny and regulation. For example, the EPA has asserted federal regulatory authority over certain hydraulic-fracturing activities under the SDWA involving the use of diesel fuels and published permitting guidance in February 2014 addressing the use of diesel in fracturing operations. Also, the EPA is updating chloride water quality criteria for the protection of aquatic life under the Clean Water Act, which criteria are used by states for establishing acceptable discharge limits. The EPA is expected to release draft criteria in early 2016. In addition, in May 2014, the EPA issued an Advanced Notice of Proposed Rulemaking seeking public comment on its intent to develop and issue regulations under the Toxic Substances Control Act regarding the disclosure of information related to the chemicals used in hydraulic fracturing. The public comment period ended on September 18, 2014. In addition, Congress has from time to time considered legislation to amend the SDWA, including legislation that would repeal the exemption for hydraulic fracturing from the definition of "underground injection" and require federal permitting and regulatory control of hydraulic fracturing, as well as legislative proposals to require disclosure of the chemical constituents of the fluids used in the fracturing process. Also, in the near future 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. The EPA is currently developing effluent limitation guidelines that may impose federal pre-treatment standards on oil and gas operators transporting wastewater associated with hydraulic fracturing activities to publicly owned treatment works for disposal. The EPA plans to propose such standards in early 2015. In addition, in May 2013, the federal Bureau of Land Management published a supplemental notice of proposed rulemaking governing hydraulic fracturing on federal and Indian lands that replaces a prior draft of proposed rulemaking issued by the agency in May 2012. The revised proposed rule would require public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the surface. The Bureau of Land Management plans to issue a final rule; however, the final release of those rules are still pending.

Further, in April 2012, the EPA released final rules that subject all oil and gas operations (production, processing, transmission, storage and distribution) to regulation under the new source performance standards ("NSPS") and the National Emission Standards for Hazardous Air Pollutants ("NESHAPS") programs. The rules include NSPS standards for completions of hydraulically fractured gas wells and establishes specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The final rules seek to achieve a 95% reduction in VOCs emitted by requiring the use of reduced emission completions or "green completions" on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules could require a number of modifications to our operations including the installation of new equipment. 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 that are likely to be responsive to some of these requests. On September 23, 2013, the EPA finalized the portion of the rules addressing VOC emissions from storage tanks, including a phase-in period and an alternative emissions limit for older tanks. On December 19, 2014, the EPA released final updates and clarification to the NSPS standards. In addition, on January 14, 2015, the EPA announced a series of steps it plans to take to address methane and smog-forming VOC emissions from the oil and gas industry. These standards, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or utilize specific equipment or technologies to control emissions. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

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Several states have adopted, or are considering adopting, regulations requiring the disclosure of the chemicals used in hydraulic fracturing and/or otherwise impose additional requirements for hydraulic fracturing activities. For example, in October 2011, the Louisiana Department of Natural Resources adopted new rules requiring the public disclosure of the composition and volume of fracturing fluids used in hydraulic fracturing operations. Also, Texas requires oil and natural gas operators to disclose to the Texas Railroad Commission and the public the chemicals used in the hydraulic fracturing process, as well as the total volume of water used. On October 28, 2014, the Texas Railroad Commission adopted disposal well rule amendments designed, amongst other things, to require applicants for new disposal wells that will receive non-hazardous produced water and hydraulic fracturing flowback fluid to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed, new disposal well. The disposal well rule amendments also clarify the Commission's authority to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The disposal well rule amendments became effective November 17, 2014. Furthermore, in May 2013, the Texas Railroad Commission issued a "well integrity rule," which updates the requirements for drilling, putting pipe down, and cementing wells. The rule also includes new testing and reporting requirements, such as (i) the requirement to submit cementing reports after well completion or after cessation of drilling, and (ii) the imposition of additional testing on wells less than 1,000 feet below usable groundwater. The "well integrity rule" took effect in January 2014. 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, which could lead to increased regulation. For example, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. The EPA has also commenced a study of the potential environmental effects of hydraulic fracturing on 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 is still pending. Other governmental agencies, including the U.S. Department of Energy, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing, and could ultimately make it more difficult or costly for us to perform fracturing and increase our costs of compliance and doing business.

A number of lawsuits and enforcement actions have been initiated across the country alleging that hydraulic fracturing practices have adversely impacted drinking water supplies, use of surface water, and the environment generally. Several states and municipalities have adopted, or are considering adopting, regulations that could restrict or prohibit hydraulic fracturing in certain circumstances. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations as well as make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, if hydraulic fracturing is further regulated at the federal, state or local level, our fracturing activities could become subject to additional permitting and financial assurance requirements, more stringent construction specifications, increased monitoring, reporting and recordkeeping obligations, plugging and abandonment requirements and also to attendant permitting delays and potential increases in costs. Such legislative changes could cause us to incur substantial compliance costs, and compliance or the consequences of any failure to comply by us could have a material adverse effect on our financial condition and results of operations. At this time, it is not possible to estimate the impact on our business of newly enacted or potential federal or state legislation governing hydraulic fracturing, and any of the above risks could impair our ability to manage our business and have a material adverse effect on our operations, cash flows and financial position.

Air Emissions

The federal Clean Air Act ("CAA"), as amended, and comparable state laws restrict the emission of air pollutants from many sources, including compressor stations, through the issuance of permits and the imposition of other 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, in April 2012, the EPA released final rules under the CAA that subject oil and natural gas production, processing, transmission and storage operations to regulation under the NSPS and NESHAPS programs. The rules include NSPS standards for completions of hydraulically fractured gas wells and establishes specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The final rules seek to achieve a 95% reduction in VOCs emitted by requiring the use of reduced emission completions or "green completions" on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules could require a number of modifications to our operations including the installation of new equipment. 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 that are likely to be responsive to some of these requests. On September 23, 2013, the EPA finalized the portion of the rules addressing VOC emissions from storage tanks, including a phase-in period and an alternative emissions limit for older tanks. On December 19, 2014 the EPA released final updates and clarification to the NSPS standards. In addition, on January 14, 2015, the EPA announced a series of steps it plans to take to address methane and smog-forming VOC emissions from the oil and gas industry.

We may be required to incur certain capital expenditures in the next few years for air pollution control equipment in connection with maintaining or obtaining operating permits addressing air emission related issues, which may have a material adverse effect on our operations. Obtaining permits also has the potential to delay the development of oil and natural gas projects. We believe that we and MEMP currently are in substantial compliance with all air emissions regulations and that we and MEMP hold all necessary and valid construction and operating permits for our current operations.

Regulation of "Greenhouse Gas" Emissions

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases ("GHGs") present an endangerment to public health and the environment, in May 2010, the EPA adopted regulations under existing provisions of the federal CAA that, among other things, established 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. The so-called Tailoring Rule established new GHG emissions thresholds that determine when stationary sources must obtain permits under the PSD and Title V programs of the Clean Air Act. On June 23, 2014, the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their GHG emissions. The Court ruled, however, that the EPA may require installation of best available control technology for GHG emissions at sources otherwise subject to the PSD or Title V programs. The EPA has announced that it is currently evaluating the decision and awaiting further action by the courts, and that it will provide relevant guidance on GHG permitting requirements.

In September 2009, the EPA issued a final rule requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, including natural gas liquids fractionators and local natural gas/distribution companies, beginning in 2011 for emissions occurring in 2010. In November 2010, the EPA published a final rule expanding the GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis, with reporting beginning in 2012 for emissions occurring in 2011. In December 2014, the EPA published a proposed rule to amend the GHG Reporting Program to add reporting of greenhouse gas emissions from gathering and boosting systems, completions and workovers of oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines. The rule is undergoing an extended public comment period until February 24, 2015. The adoption and implementation of any 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 or could adversely affect demand for the oil and natural gas we produce. Any one of these climate change regulatory and legislative initiatives could have a material adverse effect on our business, financial condition and results of operations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs 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. In addition, the Obama Administration has announced in its Climate Action Plan that it intends to adopt additional regulations to reduce emissions of GHGs in the coming years, possibly including further restrictions on emissions of methane from oil and natural gas facilities.

Restrictions on GHG emissions that may be imposed in various states could adversely affect the oil and natural gas industry. Any GHG regulation could increase our costs of compliance by potentially delaying the receipt of permits and other regulatory approvals; requiring us to monitor emissions, install additional equipment or modify facilities to reduce GHG and other emissions; purchase emission credits; and utilize electric driven compression at facilities to obtain regulatory permits and approvals in a timely manner. While we are subject to certain federal GHG monitoring and reporting requirements, our operations are not adversely impacted by existing federal, state and local climate change initiatives and, at this time, it is not possible to accurately estimate how potential future laws or regulations addressing GHG emissions would impact our business.

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 an adverse effect on our exploration and production operations.

Occupational Safety and Health Act

We are also subject to the requirements of the Occupational Safety and Health Act ("OSHA') and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazard communication standard requires that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our and MEMP's operations are in substantial compliance with the OSHA requirements.

National Environmental Policy Act

Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the Departments of Interior and Agriculture, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency prepares an environmental assessment to evaluate the potential direct, indirect and cumulative impacts of a proposed project. If impacts are considered significant, the agency will prepare a more detailed environmental impact study that is made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This environmental impact assessment process has the potential to delay the development of oil and natural gas projects. Authorizations under NEPA also are subject to protest, appeal or litigation, which can delay or halt projects.

Endangered Species Act

The federal Endangered Species Act ("ESA") and analogous state statutes restrict activities that may adversely affect endangered and threatened species or their habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The designation of previously unidentified endangered or threatened species in areas where we operate could cause us to incur additional costs or become subject to operating delays, restrictions or bans. Numerous species have been listed or proposed for protected status in areas in which we currently, or could in the future, undertake operations. For instance, the American burying beetle and the lesser prairie chicken both have habitat in some areas where we operate. The U.S. Fish and Wildlife Service ("FWS") identified the lesser prairie chicken, which inhabits portions of Colorado, Kansas, Nebraska, New Mexico, Oklahoma and Texas, as candidate for listing in 1998 and has listed it as "threatened" in March 2014. However, the FWS also announced a final rule that will limit regulatory impacts on landowners and businesses from the listing if those landowners and businesses have entered into certain range-wide conservation planning agreements, such as those developed by the Western Association of Fish and Wildlife Agencies, pursuant to which such parties agreed to take steps to protect the lesser prairie chicken's habitat and to pay a mitigation fee if its actions harm the lesser prairie chicken's habitat. The threatened species status of the lesser prairie chicken is currently subject to a pending lawsuit by at least three states.

The lawsuit challenges FWS' recent classification of the lesser prairie chicken. The presence of protected species in areas where we operate could impair our ability to timely complete or carry out those operations, lose leaseholds as we may not be permitted to timely commence drilling operations, cause us to incur increased costs arising from species protection measures, and, consequently, adversely affect our results of operations and financial position.

Summary

In summary, we believe we and MEMP are in substantial compliance with currently applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non-recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2014, 2013, and 2012.

Insurance

In accordance with customary industry practice, we and MEMP maintain insurance against many potential operational risks and losses that could be covered by the following policies:

Commercial General Liability;	Oil Pollution Act Liability;
Primary Umbrella / Excess Liability;	Pollution Legal Liability;
Property;	Charterer's Legal Liability;
Workers' Compensation;	Non-Owned Aircraft Liability;
Employer's Liability;	Automobile Liability;
Maritime Employer's Liability;	Directors & Officers Liability;
U.S. Longshore and Harbor Workers';	Employment Practices Liability;
Energy Package/Control of Well;	Crime; and
Loss of Production (offshore only);	Fiduciary

Onshore and Offshore Insurance Program. We and MEMP maintain insurance coverage against potential losses that we believe is customary in the industry. As of December 31, 2014, we maintain commercial general liability insurance, automobile liability insurance and umbrella/excess liability insurance. Our commercial general liability insurance has limits of $1.0 million per occurrence/$2.0 million in the aggregate and a $250,000 self-insured retention. Our general liability insurance covers us for, among other things, legal and contractual liabilities arising out of third party property damage and bodily injury and for sudden and accidental pollution liability. Our automobile liability insurance has limits of $1.0 million per occurrence. Our umbrella/excess liability limits for each occurrence is a minimum of $25.0 million. There is no deductible on our umbrella/excess liability insurance. Our umbrella/excess liability insurance is in addition to our general and automobile liability policy and may be triggered if the general or automobile liability insurance policy limits are exceeded and exhausted. In addition, we maintain an energy package policy that includes control of well coverage ("COW") with per occurrence limits for COW ranging from $10.0 million to $100.0 million and retentions ranging from $100,000 to $500,000. Specific to offshore operations, the energy package policy also includes loss of production income coverage insuring us against a loss up to $64.8 million due to a temporary interruption in the oil supply from our offshore facilities as a result of an insured physical loss to our offshore facilities. Our control of well policy insures us for blowout risks associated with drilling, completing and operating our wells. We maintain two separate Pollution Legal Liability ("PLL") policies, one for all U.S. onshore operations, excluding California and one for California only. Our PLL non-California insurance policy has limits of $10.0 million per pollution event with a $1.0 million deductible. Our PLL California-only insurance policy has limits of $10.0 million with a $50,000 deductible per event.

As of December 31, 2014, we have insurance policies in effect that are intended to provide coverage for pollution losses including those related to our hydraulic fracturing operations. These policies may not cover fines, penalties or costs and expenses related to government-mandated clean-up of pollution. In addition, these policies do not provide coverage for all liabilities, and we cannot assure you that the insurance coverage will be adequate to cover claims that may arise, or that we will be able to maintain adequate insurance at rates we consider reasonable. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

We enter into master services agreements, or MSAs, with various service providers. These MSAs allocate potential liabilities and risks between the parties. Under certain MSAs, we indemnify the hydraulic fracturing service providers for pollution and contamination of any kind, damages to or losses from wells or underground formations and damages to property, including pipelines, storage or production facilities. Under certain other MSAs, the service providers indemnify us for pollution or contamination that originates above the surface and is caused by the service provider's equipment or services, unless such pollution or contamination is caused by our gross negligence or willful misconduct, and we indemnify the service providers for all other pollution or contamination that may occur during operations (including that which may result from seepage or any other uncontrolled flow of oil, natural gas or other fluids from the well), unless such pollution or contamination is caused by the service provider's gross negligence or willful misconduct. Generally, we also agree to indemnify the service providers against claims arising from our employees' bodily injury or death to the extent that our employees are injured by such hydraulic fracturing operations, unless resulting from the service provider's gross negligence or willful misconduct. Similarly, the service providers generally agree to indemnify us for liabilities arising from bodily injury to or death of any of their employees, unless resulting from our gross negligence or willful misconduct. In addition, the service providers generally agree to indemnify us for loss or destruction of property or equipment that they own, unless resulting from our gross negligence or willful misconduct. In turn, we generally agree to indemnify the service providers for loss or destruction of property or equipment we own, unless resulting from the service provider's gross negligence or willful misconduct.

Despite the general allocation of risk discussed above, we may not succeed in enforcing such contractual allocation of risk, we may be required to enter into a MSA with terms that vary from such allocation of risk and may incur costs or liabilities that fall outside any contractual allocation of risk. As a result, we may incur substantial losses that could materially and adversely affect our financial position, results of operations and cash flows.

Employees

As of December 31, 2014, we had 505 full-time employees. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory.

Offices

Our executive offices are located at 500 Dallas Street, Suite 1800, Houston, Texas 77002. Our main telephone number is (713) 588-8300.

Legal Proceedings

From time to time, we are subject to various legal proceedings arising in the ordinary course of business, including proceedings for which we have insurance coverage. As of the date hereof, neither we nor MEMP are party to any material legal proceedings.

Available Information

Our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8–K and amendments to those reports filed or furnished pursuant to the Exchange Act are made available free of charge on our website at www.memorialrd.com as soon as reasonably practicable after these reports have been electronically filed with, or furnished to, the United States Securities and Exchange Commission (“SEC”). These documents are also available on the SEC’s website at www.sec.gov or you may read and copy any materials that we file with the SEC at the SEC’s Public Reference Room at 100 F Street, NE, Washington DC 20549. Our website also includes our Code of Business Conduct and Ethics and the charter of our audit committee. The information contained on, or connected to, our website is not incorporated by reference into this Form 10-K and should not be considered part of this or any other report that we file with or furnish to the SEC.

ITEM 1A. RISK FACTORS

Risks Related to Our Business

Oil, natural gas and NGL prices are volatile, due to factors beyond our control, and will greatly affect our business, results of operations, liquidity and financial condition.

Our revenues, operating results, profitability, liquidity, future growth and the value of our assets depend primarily on prevailing commodity prices. Historically, oil and natural gas prices have been volatile and fluctuate in response to changes in supply and demand, market uncertainty, and other factors that are beyond our control, including:

- the regional, domestic and foreign supply of oil, natural gas and NGLs;
- the level of commodity prices and expectations about future commodity prices;
- the level of global oil and natural gas exploration and production;
- localized supply and demand fundamentals, including the proximity and capacity of pipelines and other transportation facilities, and other factors that result in differentials to benchmark prices from time to time;
- the cost of exploring for, developing, producing and transporting reserves;
- the price and quantity of foreign imports;
- political and economic conditions in oil producing countries;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- speculative trading in crude oil and natural gas derivative contracts;
- the level of consumer product demand;
- weather conditions and other natural disasters;
- risks associated with operating drilling rigs;
- technological advances affecting exploration and production operations and overall energy consumption;
- domestic and foreign governmental regulations and taxes;
- the continued threat of terrorism and the impact of military and other action;
- the price and availability of competitors' supplies of oil and natural gas and alternative fuels; and
- overall domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil, natural gas and NGL price movements with any certainty. For example, for the five years ended December 31, 2014, the NYMEX-WTI oil future price ranged from a high of $113.93 per Bbl to a low of $53.27 per Bbl, while the NYMEX-Henry Hub natural gas future price ranged from a high of $6.15 per MMBtu to a low of $1.91 per MMBtu. Recently, oil and natural gas prices have declined significantly. Through December 31, 2014, the West Texas Intermediate posted price had declined from a high of $107.26 per Bbl on June 20, 2014 to $53.27 per Bbl on December 31, 2014. In addition, the Henry Hub spot market price had declined from a high of $6.15 per MMBtu on February 19, 2014 to a low of $2.89 per MMBtu on December 31, 2014. Any further substantial decline in commodity prices will likely have a material adverse effect on our operations and financial condition, as well as on our level of expenditures for the development of our reserves.

NGLs comprised 23% of our estimated proved reserves and accounted for 16% of our production on a volume equivalent basis for the year ended December 31, 2014. Realized NGL prices have decreased recently principally due to significant supply. NGLs are made up of ethane, propane, isobutane, normal butane and natural gasoline, all of which have different uses and different pricing characteristics. A further or extended decline in NGL prices could materially and adversely affect our future business, financial condition and results of operations.

The prices that we receive for our oil and natural gas production often reflect a regional discount, based on the location of production, to the relevant benchmark prices, such as WTI or Brent, that are used for calculating hedge positions. The prices we receive for our production are also affected by the specific characteristics of the production relative to production sold at benchmark prices. These discounts, if significant, could adversely affect our results of operations and financial condition.

We may have difficulty managing growth in our business, which could adversely affect our financial condition and results of operations.

As a recently formed public company, growth in accordance with our business plan, if achieved, could place a significant strain on our financial, technical, operational and management resources. As we expand our activities and increase the number of projects we are evaluating or in which we participate, there will be additional demands on our financial, technical, operational and management resources. In addition, the failure to continue to upgrade our technical, administrative, operating and financial control systems or the occurrences of unexpected expansion difficulties, including the failure to recruit and retain experienced managers, geologists, engineers and other professionals in the oil and natural gas industry, could have a material adverse effect on our business, financial condition and results of operations and our ability to timely execute our business plan.

Unless we replace the oil and natural gas reserves we produce, our revenues and production will decline, which would adversely affect our business, results of operations, liquidity and financial condition.

Producing oil and natural gas reservoirs are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production and therefore our cash flow and financial condition are highly dependent on our success in efficiently developing and exploiting our current reserves. Our production decline rates may be significantly higher than currently estimated if our wells do not produce as expected. Further, our decline rate may change when we drill additional wells or make acquisitions. We may not be able to develop, find or acquire additional reserves to replace our current and future production on economically acceptable terms, which would adversely affect our business, financial condition and results of operations.

If commodity prices continue to decline, a significant portion of our development projects may become uneconomic and cause write downs of the value of our oil and natural gas properties, which may adversely affect our financial condition and liquidity.

As discussed above, recently oil, natural gas, and NGL prices, have declined significantly. A further or extended decline in commodity prices could render many of our development and production projects uneconomic and result in a reduction of our estimated reserves, which would reduce the borrowing base under our revolving credit facility and our ability to finance planned or desired capital expenditures or acquisitions.

Deteriorating commodity prices may cause us to recognize impairments in the value of our properties. In addition, if our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our properties for impairments. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that may result in a total loss of investment or otherwise adversely affect our business, financial condition or results of operations.

Our drilling activities are subject to many risks. For example, we cannot assure you that wells drilled by us will be productive or that we will recover all or any portion of our investment in such wells. Drilling for oil and natural gas often involves unprofitable efforts, not only from dry holes but also from wells that are productive but do not produce sufficient oil or natural gas to return a profit at then-realized prices after deducting drilling, operating and other costs. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or natural gas is present or that it can be produced economically. The costs of exploration, exploitation and development activities are subject to numerous uncertainties beyond our control, and increases in those costs can adversely affect the economics of a project. Further, our drilling and producing operations may be curtailed, delayed, canceled or otherwise negatively impacted as a result of other factors, including:

unusual or unexpected geological formations;
loss of drilling fluid circulation;
loss of well control;
title problems;
facility or equipment malfunctions;
unexpected operational events;
shortages or delivery delays or increases in the cost of equipment and services;
reductions in oil, natural gas and NGL prices;
lack of proximity to and shortage of capacity of transportation facilities;

- the limited availability of financing at acceptable rates;
- delays imposed by or resulting from compliance with environmental and other governmental or regulatory requirements, which may include limitations on hydraulic fracturing or the discharge of greenhouse gases; and
- adverse weather conditions and natural disasters.

Any of these risks can cause substantial losses, including personal injury or loss of life, damage to or destruction of property, natural resources and equipment, pollution, environmental contamination or loss of wells and other regulatory penalties. In the event that planned operations are delayed or cancelled, or existing wells or development wells have lower than anticipated production due to one or more of the factors above or for any other reason, our financial condition and results of operations may be adversely affected.

Part of our strategy involves using 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.

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.

Our development and exploratory drilling efforts and our well operations may not be profitable or achieve our targeted returns.

We own a significant amount of unproved property, which we expect to further our development efforts. We intend to continue to undertake acquisitions of unproved properties in the future. Development and exploratory drilling and production activities are subject to many risks, including the risk that no commercially productive reservoirs will be discovered. We acquire unproved properties and lease undeveloped acreage that we believe will enhance our growth potential and increase our results of operations over time. However, we cannot assure you that all prospects will be economically viable or that we will not abandon our investments. Additionally, we cannot assure you that unproved property acquired by us or undeveloped acreage leased by us will be profitably developed, that wells drilled by us in prospects that we pursue will be productive or that we will recover all or any portion of our investment in such unproved property or wells.

Our acreage must be drilled before lease expiration, generally within three to five years, in order to hold the acreage by production. In a highly competitive market for acreage, failure to drill sufficient wells to hold acreage may result in a substantial lease renewal cost, or if renewal is not feasible, loss of our lease and prospective drilling opportunities.

Leases on oil and natural gas properties typically have a term of three to five years, after which they expire unless, prior to expiration, production is established within the spacing units covering the undeveloped acres. As of December 31, 2014, we had 27,827 gross (18,891 net) acres scheduled to expire in 2015, 37,342 gross (24,440 net) acres scheduled to expire in 2016, and 24,169 gross (14,223 net) acres scheduled to expire in 2017. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. Moreover, many of our leases require lessor consent to pool, which may make it more difficult to hold our leases by production. Any reduction in our current drilling program, either through a reduction in capital expenditures or the unavailability of drilling rigs, could result in the loss of acreage through lease expirations. In addition, in order to hold our current leases scheduled to expire in 2015 and 2016 in the Terryville Complex, we will need to operate at least a one-rig program. We cannot assure you that we will have the liquidity to deploy these rigs when needed, or that commodity prices will warrant operating such a drilling program. Any such losses of leases could materially and adversely affect the growth of our asset base, cash flows 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.

Our project areas, which are in various stages of development, may not yield oil or natural gas in commercially viable quantities.

Our project areas are in various stages of development, ranging from project areas with current drilling or production activity to project areas that consist of recently acquired leasehold acreage or that have limited drilling or production history. At December 31, 2014, 27 gross (22.9 net) wells were in various stages of drilling and completion. If the wells in the process of being completed do not produce sufficient revenues to return a profit or if we drill dry holes in the future, our business may be materially affected. From January 2012 through December 31, 2014, we have drilled 87 gross (70.3 net) wells and none of the wells were dry holes.

Our identified drilling locations, which are scheduled out over many years, are susceptible to uncertainties that could materially alter the occurrence or timing of their drilling.

Our ability to drill and develop our identified potential drilling locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory changes and approvals, negotiation of agreements with third parties, commodity prices, costs, the generation of additional seismic or geological information, the availability of drilling rigs, drilling results, construction of infrastructure, inclement weather, and lease expirations.

Further, our identified potential drilling locations are in various stages of evaluation, ranging from locations that are ready to drill to locations that will require substantial additional analysis of data. We cannot predict in advance of drilling and testing whether any particular drilling location will yield production in sufficient quantities to recover drilling or completion costs or to be economically viable. Even if sufficient amounts of oil or natural gas reserves exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, possibly resulting in a reduction in production from the well or abandonment of the well. If we drill dry holes in our current and future drilling locations, our drilling success rate may decline and materially harm our business. We also have limited experience in drilling horizontal wells in the zones of the Terryville Complex to which we have ascribed a substantial majority of our gross identified drilling locations. We cannot assure you that the analogies we draw from available data from other wells, more fully explored locations or producing fields will be applicable to our drilling locations. Further, initial production rates reported by us or other operators in our areas of operations may not be indicative of future or long-term production rates.

Because of these uncertainties, we do not know if the potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas reserves from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business, financial condition and results of operations.

We have identified drilling, recompletion and development locations and prospects for future drilling, recompletion and development. These drilling, recompletion and development locations represent a significant part of our future drilling and enhanced recovery opportunity plans. Our ability to drill, recomplete and develop these locations depends on a number of factors, including the availability of capital, seasonal conditions, regulatory approvals, negotiation of agreements with third parties, commodity prices, costs, the generation of additional seismic or geological information, the availability of drilling rigs, and drilling results. Because of these uncertainties, we cannot be certain of the timing of these activities or that they will ultimately result in the realization of estimated proved reserves or meet our expectations for success. As such, our actual drilling and enhanced recovery activities may materially differ from our current expectations, which could have a significant adverse effect on our estimated reserves, financial condition and results of operations.

The development of our proved undeveloped and unproved reserves may take longer and may require higher levels of capital expenditures than we anticipate and may not be economically viable.

Approximately 67% of our total proved reserves at December 31, 2014 were proved undeveloped reserves; those reserves may not be ultimately developed or produced. Recovery of proved undeveloped reserves requires significant capital expenditures and successful drilling operations. The reserve data included in our reserve report assumes that substantial capital expenditures are required to develop such undeveloped reserves. We cannot be certain that the estimated costs of the development of these reserves are accurate, that development will occur as scheduled or that the results of such development will be as estimated. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce future net revenues of our estimated proved undeveloped 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 proved reserves as proved undeveloped reserves.

Our acquisition and development operations require substantial capital expenditures.

The development and production of our oil and natural gas reserves requires substantial capital expenditures. If our revenues decrease, as a result of lower oil or natural gas prices or for any other reason, we may not be able to obtain the capital necessary to sustain our operations at our current level. In addition, our ability to acquire additional properties will be adversely affected if we are unable to fund such acquisitions from cash flow from operations or other sources.

Shortages of rigs, equipment and crews could delay our operations, increase our costs and delay forecasted revenue.

Higher oil and natural gas prices generally increase the demand for rigs, equipment, supplies and crews and can lead to shortages of, and increasing costs for, development equipment, supplies, services and personnel. Shortages of, or increasing costs for, experienced development crews and oil field equipment and services could restrict our ability to drill the wells and conduct the operations that we currently have planned. Any delay in the development of new wells or a significant increase in development costs could reduce our revenues and impact our development plan, which would thus affect our financial condition and results of operations.

Our hedging strategy may not effectively mitigate the impact of commodity price volatility from our cash flows, and our hedging activities could result in cash losses and may limit potential gains.

We intend to maintain a portfolio of commodity derivative contracts. These commodity derivative contracts include natural gas, oil and NGL financial swaps, put options and collar contracts and natural gas basis financial swaps. The prices and quantities at which we enter into commodity derivative contracts covering our production in the future will be dependent upon oil and natural gas prices and price expectations at the time we enter into these transactions, which may be substantially higher or lower than current or future oil and natural gas prices. Accordingly, our price hedging strategy may not protect us from significant declines in oil and natural gas prices received for our future production. In addition, our revolving credit facility limits our ability to enter into commodity hedges covering greater than 85% of our reasonably anticipated projected production. Many of the derivative contracts to which we will be a party will require us to make cash payments to the extent the applicable index exceeds a predetermined price, thereby limiting our ability to realize the benefit of increases in oil and natural gas prices. If our actual production and sales for any period are less than our hedged production and sales for that period (including reductions in production due to operational delays) or if we are unable to perform our drilling activities as planned, we might be forced to satisfy all or a portion of our hedging obligations without the benefit of the cash flow from our sale of the underlying physical commodity, which may materially impact our liquidity.

Our hedging transactions expose us to counterparty credit risk.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets or other unforeseen events could lead to sudden changes in a counterparty's liquidity, which could impair its ability to perform under the terms of a derivative contract and, accordingly, prevent us from realizing the benefit of such a derivative contract.

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

The process of estimating natural gas and oil 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 our estimated quantities and present value of our reserves.

In order to prepare our 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 natural gas prices, oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, oil prices, natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust our reserve estimates to reflect production history, results of exploration and development, existing commodity prices and other factors, many of which are beyond our control.

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 our 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.

Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves, which could adversely affect our business, results of operations and financial condition.

SEC rules could limit our ability to book additional PUDs in the future.

SEC rules require that, subject to limited exceptions, PUDs may only be booked if they relate to wells scheduled to be drilled within five years after the date of booking. This requirement has limited and may continue to limit our ability to book additional PUDs as we pursue our drilling program. Moreover, we may be required to write down our PUDs if we do not drill those wells within the required five-year timeframe.

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

The present value of future net cash flows from our proved reserves shown in this report, or standardized measure, and our PV-10 may not be the current market value of our estimated natural gas and oil reserves. In accordance with rules established by the SEC and the Financial Accounting Standards Board (“FASB”), we base the estimated discounted future net cash flows from our proved reserves on the 12-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first-day-of-the-month price for each month and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

Our producing properties are concentrated in North Louisiana, making us vulnerable to risks associated with operating in one major geographic area.

Our producing properties are geographically concentrated in North Louisiana. At December 31, 2014, 85.6% of our total estimated proved reserves and for the year ended December 31, 2014, 86.1% of our net average daily production was attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, availability of equipment and personnel, water shortages or other drought related conditions or interruption of the processing or transportation of oil, natural gas or NGLs.

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

Concerns over global economic conditions, energy costs, geopolitical issues, inflation, the availability and cost of credit, the European debt crisis, the United States mortgage market and a weak real estate market in the United States have contributed to increased economic uncertainty and diminished expectations for the global economy. These factors, combined with volatile prices of oil, natural gas and NGLs, declining business and consumer confidence and increased unemployment, have precipitated an economic slowdown and a recession. In addition, continued hostilities in the Middle East and the occurrence or threat of terrorist attacks in the United States or other countries could adversely affect the economies of the United States and other countries. Concerns about global economic growth have had a significant adverse impact on global financial markets and commodity prices. If the economic climate in the United States or abroad deteriorates further, worldwide demand for petroleum products could diminish, which could impact the price at which oil, natural gas and NGLs from our properties are sold, affect the ability of vendors, suppliers and customers associated with our properties to continue operations and ultimately adversely impact our results of operations and financial condition.

Expenses not covered by our insurance could have a material adverse effect on our financial position, results of operations and cash flows.

Our operations are subject to all of the hazards and operating risks associated with drilling for and production of oil and natural gas, including natural disasters, the risk of fire, explosions, blowouts, surface cratering, uncontrollable flows of natural gas, oil and formation water, pipe or pipeline failures, abnormally pressured formations, casing collapses and environmental hazards such as oil spills, natural gas leaks, ruptures or discharges of toxic gases, all of which could cause substantial financial losses. In addition, our operations are subject to risks associated with hydraulic fracturing, including any mishandling, surface spillage or potential underground migration of fracturing fluids, including chemical additives. The location of any properties and other assets near populated areas, including residential areas, commercial business centers and industrial sites, could significantly increase the level of damages resulting from these risks. The occurrence of any of these events could result in substantial losses to us due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties, suspension of operations, substantial revenue losses and repairs to resume operations.

We maintain insurance coverage against potential losses that we believe is customary in the industry. However, these policies may not cover all liabilities, claims, fines, penalties or costs and expenses that we may incur in connection with our business and operations, including those related to environmental claims. Pollution and environmental risks generally are not fully insurable. In addition, we cannot assure you that we will be able to maintain adequate insurance at rates we consider reasonable. We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations and cash flows.

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.

Any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about estimated proved reserves, future production, revenues, capital expenditures, operating expenses and costs;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which any indemnity we receive is inadequate;
- an inability to obtain satisfactory title to the assets we acquire; and
- potential lack of operating experience in the geographic market where the acquired assets or business are located.

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.

Properties we acquire may not produce as projected, and we may be unable to determine reserve potential, identify liabilities associated with the properties that we acquire or obtain protection from sellers against such liabilities.

Acquiring oil and natural gas properties requires us to assess reservoir and infrastructure characteristics, including recoverable reserves, development and operating costs and potential environmental and other liabilities. Such assessments are inexact and inherently uncertain. In connection with the assessments, we perform a review of the subject properties, but such a review will not necessarily reveal all existing or potential problems. In the course of our due diligence, we may not inspect every well or pipeline. We cannot necessarily observe structural and environmental problems, such as pipe corrosion, when an inspection is made. We may not be able to obtain contractual indemnities from the seller for liabilities created prior to our purchase of the property. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

NGP, the Funds and their affiliates are not limited in their ability to compete with us, which could cause conflicts of interest and limit our ability to acquire additional assets or businesses.

Our governing documents provide that NGP and the Funds and their respective affiliates (including NGP and its affiliates' portfolio investments) are not restricted from owning assets or engaging in businesses that compete directly or indirectly with us. In addition, NGP and the Funds and their respective affiliates may acquire, develop or dispose of additional oil and natural gas properties or other assets in the future, without any obligation to offer us the opportunity to purchase or develop any of those assets. NGP and the Funds are established participants in the oil and natural gas industry, and have resources greater than ours, which factors may make it more difficult for us to compete with them with respect to commercial activities as well as for potential acquisitions. As a result, competition from these affiliates could adversely impact our results of operations.

We may be unable to compete effectively with larger companies.

The oil and natural gas industry is intensely competitive with respect to acquiring prospects and productive properties, marketing oil and natural gas, and securing equipment and trained personnel. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Many of our larger competitors not only drill for and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis, and many of our competitors have access to capital at a lower cost than that available to us. These companies may be able to pay more for oil and natural gas properties and evaluate, bid for and purchase a greater number of properties than our financial, technical or personnel resources permit. In addition, there is substantial competition for investment capital in the oil and natural gas industry. These larger companies may have a greater ability to continue development activities during periods of low oil and natural gas prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Furthermore, we may not be able to aggregate sufficient quantities of production to compete with larger companies that are able to sell greater volumes of production to intermediaries, thereby reducing the realized prices attributable to our production. Any inability to compete effectively with larger companies could have a material adverse impact on our business activities, financial condition and results of operations.

We require substantial capital expenditures to conduct our operations, engage in acquisition activities and replace our production, and we may be unable to obtain needed financing on satisfactory terms necessary to execute our operating strategy.

We require substantial capital expenditures to conduct our exploration, development and production operations, engage in acquisition activities and replace our production. We intend to rely on cash flow from operating activities and borrowings under our revolving credit facility as our primary sources of liquidity. We also may engage in asset and equity sale transactions to, among other things, fund capital expenditures when market conditions permit us to complete transactions on terms we find acceptable. There can be no assurance that such sources will be sufficient to fund our exploration, development and acquisition activities. If our revenues and cash flows decrease in the future as a result of a further decline in commodity prices or a reduction in production levels, however, and we are unable to obtain additional equity or debt financing in the capital markets or access alternative sources of funds, we may be required to reduce the level of our capital expenditures and may lack the capital necessary to replace our reserves or maintain our production levels.

Our business depends in part on pipelines, gathering systems and processing facilities owned by us or others. Any limitation in the availability of those facilities could interfere with our ability to market our oil and natural gas production.

The marketability of our oil and natural gas production depends in part on the availability, proximity and capacity of pipelines and other transportation methods, gathering systems and processing facilities owned by third parties. The amount of oil and natural gas that can be produced and sold is subject to curtailment in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage or lack of contracted capacity on such systems. Our access to transportation options can also be affected by U.S. federal and state regulation of oil and natural gas production and transportation, general economic conditions and changes in supply and demand. The curtailments arising from these and similar circumstances may last from a few days to several months. In many cases, we are provided with only limited, if any, notice as to when these circumstances will arise and their duration. Any significant curtailment in gathering system or transportation or processing facility capacity could reduce our ability to market our oil and natural gas production and harm our business.

Our use of 2-D and 3-D 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, which could have a material adverse impact on our financial condition and results of operations.

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 services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

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.

Our natural gas and oil exploration, production, and transportation operations are subject to complex and stringent laws and regulations. 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. In addition, the trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment and thus, 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. Failure to comply with laws and regulations applicable to our operations, including any evolving interpretation and enforcement by governmental authorities, could have a material adverse effect on our business, financial condition, and results of operations.

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

Certain environmental laws impose strict as well as joint and several liability for costs required to remediate and restore sites where hazardous substances, hydrocarbons, or solid wastes have been stored or released. We may be required to remediate contaminated properties currently or formerly operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, prospects, financial condition or results of operations could be materially adversely affected.

Please read "Item 1. Business—Regulation of Environmental and Occupational Health and Safety Matters" for a further description of the laws and regulations that affect us.

Climate change legislation or regulations restricting emissions of “greenhouse gases,” or GHGs could result in increased operating costs and reduced demand for the oil and natural gas that we produce.

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases (“GHGs”), including carbon dioxide and methane, may be contributing to warming of the earth’s atmosphere and other climatic changes. In December 2009, the EPA published its findings that emissions of GHGs present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth’s atmosphere and other climatic changes. Based on these findings, the EPA adopted regulations under existing provisions of the federal Clean Air Act (“CAA”) that establish Prevention of Significant Deterioration, or PSD, and Title V permit reviews for GHG emissions from certain large stationary sources. On June 23, 2014, the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their GHG emissions. The Court ruled, however, that the EPA may require installation of best available control technology for GHG emissions at sources otherwise subject to the PSD or Title V programs. The EPA has announced that it is currently evaluating the decision and awaiting further action by the courts, and that it will provide relevant guidance on GHG permitting requirements.

The EPA has also adopted rules requiring the monitoring and reporting of GHG emissions from specified sources on an annual basis in the United States, including, among others, certain oil and natural gas production facilities, which includes certain of our operations. The adoption and implementation of any 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 or could adversely affect demand for the oil and natural gas we produce. Any one of these climate change regulatory and legislative initiatives could have a material adverse effect on our business, financial condition and results of operations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs 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. In addition, the Obama administration has announced in its Climate Action Plan that it intends to adopt additional regulations to reduce emissions of GHGs in the coming years, possibly including further restrictions on emissions of methane from oil and gas operations.

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 that require reporting of GHGs or otherwise limit emissions of GHGs from our equipment and operations could require us to incur costs to monitor and report on GHG emissions or reduce emissions of GHGs associated with our operations, and such requirements also could adversely affect demand for the oil and natural gas that 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, droughts and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations. Please read “Item 1. Business—Regulation of Environmental and Occupational Health and Safety Matters” for a further description of the laws and regulations that affect us.

The listing of a species as either “threatened” or “endangered” under the federal Endangered Species Act could result in increased costs and new operating restrictions, loss of leasehold or delays on our operations, which could adversely affect our results of operations and financial condition.

The federal ESA and analogous state laws restrict activities that may adversely affect endangered and threatened species or their habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The designation of previously unidentified endangered or threatened species in areas where we operate could cause us to incur additional costs or become subject to operating delays, restrictions or bans. Numerous species have been listed or proposed for protected status in areas in which we currently, or could in the future, undertake operations. For instance, the American burying beetle and the lesser prairie chicken both have habitat in some areas where we operate. The FWS identified the lesser prairie chicken, which inhabits portions of Colorado, Kansas, Nebraska, New Mexico, Oklahoma and Texas, as candidate for listing in 1998 and has listed it as “threatened” in March 2014. However, the FWS also announced a final rule that will limit regulatory impacts on landowners and businesses from the listing if those landowners and businesses have entered into certain range-wide conservation planning agreements, such as those developed by the Western Association of Fish and Wildlife Agencies, pursuant to which such parties agreed to take steps to protect the lesser prairie chicken’s habitat and to pay a mitigation fee if its actions harm the lesser prairie chicken’s habitat. The threatened species status of the lesser prairie chicken is currently subject to a pending lawsuit by at least three states. The lawsuit challenges FWS’ recent classification of the lesser prairie chicken. The presence of protected species in areas where we operate could impair our ability to timely complete or carry out those operations, lose leaseholds as we may not be permitted to timely commence drilling operations, cause us to incur increased costs arising from species protection measures, and, consequently, adversely affect our results of operations and financial position.

The third parties on whom we rely for gathering and transportation services are subject to complex federal, state and other laws that could adversely affect the cost, manner or feasibility of conducting our business.

The operations of the third parties on whom we rely for gathering and transportation services are subject to complex and stringent laws and regulations that require obtaining and maintaining numerous permits, approvals and certifications from various federal, state and local government authorities. These third parties may incur substantial costs in order to comply with existing laws and regulations. If existing laws and regulations governing such third-party services are revised or reinterpreted, or if new laws and regulations become applicable to their operations, these changes may affect the costs that we pay for such services. Similarly, a failure to comply with such laws and regulations by the third parties on whom we rely could have a material adverse effect on our business, financial condition and results of operations. See “Item 1. Business—Regulation of Environmental and Occupational Health and Safety Matters” and “Item 1. Business—Regulation of the Oil and Natural Gas Industry” for a description of the laws and regulations that affect the third parties on whom we rely.

Derivatives reform legislation and related regulations could have an adverse effect on our ability to hedge risks associated with our business.

The July 2010 Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, provides for federal oversight of the over-the-counter derivatives market and entities that participate in that market and mandates that the Commodity Futures Trading Commission, or CFTC, adopt rules or regulations implementing the Dodd-Frank Act and providing definitions of terms used in the Dodd-Frank Act. The Dodd-Frank Act establishes margin requirements and requires clearing and trade execution practices for certain market participants and may result in certain market participants needing to curtail or cease their derivatives activities. Although some of the rules necessary to implement the Dodd-Frank Act remain to be adopted, the CFTC has issued a large number of rules to implement the Dodd-Frank Act, including a rule establishing an “end-user” exception to mandatory clearing, referred to herein as the “End-User Exception,” and a rule imposing position limits, referred to herein as the Initial Position Limit Rule. The Initial Position Limit Rule was vacated and remanded to the CFTC for further proceedings by order of the United States District Court for the District of Columbia on September 28, 2012. The CFTC proposed a new version of the Initial Position Limit Rule in November 2013, referred to herein as the “Re-Proposed Position Limit Rule,” with respect to which the comment period has closed but a final rule has not been issued. The CFTC and bank regulators in September 2014 reproposed rules which would impose margin requirements on uncleared swaps between banks, swap dealers and major swap participants, referred to herein as the “Re-Proposed SD/MSP Margin Rule.”

We qualify as a “non-financial entity” for purposes of the End-User Exception and we utilize such exception so our hedging activity is not subject to mandatory clearing or the margin requirements imposed in connection with mandatory clearing. However, most if not all of our hedge counterparties will be subject to mandatory clearing in connection with their hedging activities with parties who do not qualify for the End-User Exception and, if the Re-Proposed SD/MSP Margin Rule is adopted, will be subject to such rule and required to post margin in accordance with such rule in connection with their swaps with other banks, swap dealers and major swap participants. The Dodd-Frank Act, the rules which have been adopted and not vacated, and, to the extent that the Re-Proposed Position Limit Rule and the Re-Proposed SD/MSP Margin Rule are ultimately effected, such proposed rules could significantly increase the cost of derivative contracts (including through requirements to post collateral), materially alter the terms of derivative contracts, 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 regulations, 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 contracts related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition, and our results of operations.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays, and adversely affect our production.

Hydraulic fracturing is an essential and common practice in the oil and gas industry used to stimulate production of natural gas and/or oil from dense subsurface rock formations. Hydraulic fracturing involves using water, sand, and certain chemicals to fracture the hydrocarbon-bearing rock formation to allow flow of hydrocarbons into the wellbore. We routinely apply hydraulic fracturing techniques in our drilling and completion programs.

While hydraulic fracturing has historically been regulated by state oil and natural gas commissions, the practice has become increasingly controversial in certain parts of the country, resulting in increased scrutiny and regulation. For example, the EPA has asserted federal regulatory authority over certain hydraulic-fracturing activities under the Safe Drinking Water Act, or the SDWA, involving the use of diesel fuels and published permitting guidance in February 2014 addressing the use of diesel in fracturing operations. Although the EPA is not the permitting authority for the SDWA's Underground Injection Control Class II programs in Louisiana, Texas, Wyoming, New Mexico, or Colorado, where we or MEMP maintain operational acreage, the EPA is encouraging state programs to review and consider use of such draft guidance. Also, the EPA is updating chloride water quality criteria for the protection of aquatic life under the Clean Water Act, which criteria are used by states for establishing acceptable discharge limits. The EPA is expected to release draft criteria in early 2016. In addition, in October 2011, the EPA announced its plan to propose federal pre-treatment standards for wastewater generated during the hydraulic fracturing process. Hydraulic fracturing stimulation requires the use of a significant volume of water with some resulting "flowback," as well as "produced water." If adopted, the new pretreatment rules will require shale gas operations to pretreat wastewater before transferring it to treatment facilities. A proposed rule is expected in early 2015. Moreover, in May 2014, the EPA issued an Advanced Notice of Proposed Rulemaking seeking public comment on its intent to develop and issue regulations under the Toxic Substances Control Act regarding the disclosure of information related to the chemicals used in hydraulic fracturing. The public comment period ended on September 18, 2014.

In August 2012, the EPA adopted rules that subject oil and natural gas production, processing, transmission, and storage operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants programs. The rules include NSPS standards for completions of hydraulically fractured gas wells and establishes specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The final rules seek to achieve a 95% reduction in VOCs emitted by requiring the use of reduced emission completions or "green completions" on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules could require a number of modifications to our operations including the installation of new equipment. 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 that are likely to be responsive to some of these requests. On September 23, 2013, the EPA finalized the portion of the rules addressing VOC emissions from storage tanks, including a phase-in period and an alternative emissions limit for older tanks. On December 19, 2014, the EPA released final updates and clarifications to the NSPS standards. In addition, on January 14, 2015, the EPA announced a series of steps it plans to take to address methane and smog-forming VOC emissions from the oil and gas industry. These standards, as well as any future laws and their implementing regulations, may require us to obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or utilize specific equipment or technologies to control emissions. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

In addition, in May 2013, the federal Bureau of Land Management published a supplemental notice of proposed rulemaking governing hydraulic fracturing on federal and Indian lands that replaces a prior draft of proposed rulemaking issued by the agency in May 2012. The revised proposed rule would continue to require public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the surface. The Bureau of Land Management plans to issue a final rule; however, the final release of those rules are still pending.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. A draft report is expected to be released for public comment; however the report is still pending. The EPA's study could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing.

Additionally, Congress from time to time has considered the adoption of legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. Certain states, including Texas and Colorado, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether. For example, in October 2011, the Louisiana Department of Natural Resources adopted new rules requiring the public disclosure of the composition and volume of fracturing fluids used in hydraulic fracturing operations. Also, October 28, 2014, the Texas Railroad Commission adopted disposal well rule amendments designed, amongst other things, to require applicants for new disposal wells that will receive non-hazardous produced water and hydraulic fracturing flowback fluid to conduct seismic activity searches utilizing the U.S. Geological Survey. The searches are intended to determine the potential for earthquakes within a circular area of 100 square miles around a proposed, new disposal well. The disposal well rule amendments also clarify the Commission's authority to modify, suspend or terminate a disposal well permit if scientific data indicates a disposal well is likely to contribute to seismic activity. The disposal well rule amendments became effective November 17, 2014. Furthermore, in May 2013, the Texas Railroad Commission adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. In addition to state laws, local land use restrictions, such as city ordinances, may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular. In the event state, local, or municipal legal restrictions are adopted in areas where we are currently conducting, or in the future plan to conduct operations, we may incur additional costs to comply with such requirements that may be significant in nature, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from the drilling of wells.

If these or any other new laws or regulations that significantly restrict hydraulic fracturing are adopted at the state and local level, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from dense subsurface rock formations and, in the event of local prohibitions against commercial production of natural gas, may preclude our ability to drill wells. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA or other federal agencies, our fracturing activities could become subject to additional permitting requirements and result in permitting delays as well as potential increases in costs. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Oil and natural gas producers' operations, especially those using hydraulic fracturing, are substantially dependent on the availability of water. Restrictions on the ability to obtain water may impact our operations.

Water is an essential component of oil and natural gas production during the drilling, and in particular, hydraulic fracturing, process. Our inability to locate sufficient amounts of water, or dispose of or recycle water used in our exploration and production operations, could adversely impact our operations. Moreover, the imposition of new environmental requirements could include restrictions on our ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other wastes associated with the exploration, development or production of natural gas. The Federal Water Pollution Control Act (the "CWA") imposes restrictions and strict controls regarding the discharge of produced waters and other natural gas and oil waste into navigable waters. Permits must be obtained to discharge pollutants to waters and to conduct construction activities in waters and wetlands. The CWA and similar state laws provide for civil, criminal and administrative penalties for any unauthorized discharges of pollutants and unauthorized discharges of reportable quantities of oil and other hazardous substances. State and federal discharge regulations prohibit the discharge of produced water and sand, drilling fluids, drill cuttings and certain other substances related to the natural gas and oil industry into coastal waters. Also, the EPA has adopted regulations requiring certain natural gas and oil exploration and production facilities to obtain permits for storm water discharges. Compliance with current and future environmental regulations and permit requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells may increase our operating costs and cause delays, interruptions or termination of our operations, the extent of which cannot be predicted.

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

We may incur significant delays, costs and liabilities as a result of federal, state and local environmental, health and safety requirements applicable to our exploration, development and production activities. These laws and regulations may, among other things: (i) require us to obtain a variety of permits or other authorizations governing air emissions, water discharges, waste disposal or other environmental impacts associated with drilling, producing and other operations; (ii) regulate the sourcing and disposal of water used in the drilling, fracturing and completion processes; (iii) limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier and other protected areas; (iv) require remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits; and/or (v) impose substantial liabilities for spills, pollution or failure to comply with regulatory filings. In addition, these laws and regulations may restrict the rate of oil or natural gas production. These laws and regulations are complex, change frequently and have tended to become increasingly stringent over time. 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, the suspension or revocation of necessary permits, licenses and authorizations, the requirement that additional pollution controls be installed and, in some instances, the issuance of orders or injunctions limiting or requiring discontinuation of certain operations. Under certain environmental laws that impose strict as well as joint and several liability, we may be required to remediate contaminated properties operated by us or facilities of third parties that received waste generated by our operations regardless of whether such contamination resulted from the conduct of others or from consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations. In addition, the risk of accidental and/or unpermitted spills or releases from our operations could expose us to significant liabilities, penalties and other sanctions under applicable laws. Moreover, public interest in the protection of the environment has increased dramatically in recent years. The trend of more expansive and stringent environmental legislation and regulations applied to the crude oil and natural gas industry could continue, resulting in increased costs of doing business and consequently affecting profitability. To the extent laws are enacted or other governmental action is taken that restricts drilling or imposes more stringent and costly operating, waste handling, disposal and cleanup requirements, our business, financial condition and results of operations could be materially adversely affected.

We are not the only partners in MEMP, and MEMP's partnership agreement requires it to distribute all available cash to its partners, including public unitholders.

MEMP is a publicly traded limited partnership. We own MEMP GP, the sole general partner of MEMP, and are entitled to 50% of any cash distributed in respect of MEMP's incentive distribution rights. MRD Holdco owns 5,360,912 common units representing an approximate 6.0% limited partner interest in MEMP. The remainder of the outstanding limited partner interests in MEMP are common units owned by public unitholders. MEMP's partnership agreement requires it to distribute, on a quarterly basis, 100% of its available cash to its partners. We receive only our proportionate share of cash distributions from MEMP based on our partner interests in it. The remainder of the quarterly cash distributions is distributed, pro rata, to the public unitholders (and, in the case of 50% of the incentive distribution rights, to the Funds).

For MEMP, available cash is generally all cash on hand at the end of each quarter, after payment of fees and expenses and the establishment of cash reserves by its general partner. MEMP GP determines the amount and timing of cash distributions by MEMP and has broad discretion to establish and make additions to MEMP's reserves in amounts the general partner determines to be necessary or appropriate:

- to provide for the proper conduct of partnership business, which could include, but is not limited to, amounts reserved for capital expenditures, working capital and operating expenses;
- to comply with applicable law, any of MEMP's debt instruments or other agreements; and

to provide funds for distributions to the unitholders and the general partner for any one or more of the next four calendar quarters.

Accordingly, cash distributions we receive on our MEMP partner interests may be reduced at any time, or we may not receive any cash distributions from MEMP.

The amount of cash that MEMP will be able to distribute to us principally depends upon the amount of cash it can generate from its oil and natural gas production business.

A significant decline in MEMP's earnings or cash distributions would have a negative impact on its distributions to its partners, including us. The amount of cash that MEMP will be able to distribute to its partners, including us, each quarter principally depends upon the amount of cash it can generate from its oil and natural gas production business. That amount of cash will fluctuate from quarter to quarter based on, among other things:

- the amount of oil, natural gas and NGLs MEMP produces;
- the prices at which MEMP sells its oil, natural gas and NGL production;
- the amount and timing of settlements of its commodity derivatives;
- the level of MEMP's operating costs, including maintenance capital expenditures and payments to MEMP GP and its affiliates; and
- the level of MEMP's interest expense, which depends on the amount of its indebtedness and the interest payable thereon.

Because of these factors, MEMP may not have sufficient available cash each quarter to continue paying distributions at their current level or at all. In addition, the incentive distribution rights are only entitled to distributions from MEMP in any quarter if MEMP has paid at least $0.54625 on each outstanding common unit for such quarter. If MEMP reduces its per unit distribution below such amounts, we will receive less cash.

Conflicts of interest may arise because the board of directors of MEMP GP has a fiduciary duty to manage the general partner in a manner that is beneficial to the owner of MEMP GP, and at the same time, to manage MEMP in a manner that is beneficial to the MEMP unitholders. Conflicts may also arise because our executive officers have significant equity interests in MEMP.

We own MEMP GP, the sole general partner of MEMP. MEMP is a publicly traded limited partnership. The board of directors of MEMP GP owes specified duties to the MEMP unitholders, and also owes specified duties to us as owner of MEMP GP. As a result of these conflicts, the board of directors of MEMP GP may favor the interests of the MEMP public unitholders over our interests. Our executive officers have significant equity interests in MEMP. As of January 9, 2015, Mr. Weinzierl, our Chief Executive Officer, owns 556,420 MEMP common units; Mr. Scarff, our President, owns 96,943 MEMP common units; Mr. Cozby, our Senior Vice President and Chief Financial Officer, owns 152,424 MEMP common units; Mr. Forney, our Senior Vice President and Chief Operating Officer, owns 142,895 MEMP common units; Mr. Roane, our Senior Vice President, General Counsel and Corporate Secretary, owns 86,825 MEMP common units; and Mr. Robbins, our Senior Vice President, Corporate Development, owns 89,707 MEMP common units. As a result of our executive officers' significant holdings of MEMP common units, our executive officers may favor the interests of MEMP over our interests.

If MEMP's unitholders remove MEMP GP, we would lose our general partner interest and incentive distribution rights in MEMP and the ability to manage MEMP.

We currently manage our investment in MEMP through our ownership interest in MEMP GP. MEMP's partnership agreement, however, gives unitholders of MEMP the right to remove its general partner upon the affirmative vote of holders of 66 2/3% of the MEMP's outstanding units. If MEMP GP were removed as general partner of MEMP, it would receive cash or common units in exchange for its 0.1% general partner interest and incentive distribution rights and would also lose its ability to manage MEMP. While the cash or common units the general partner would receive are intended under the terms of MEMP's partnership agreement to fully compensate MEMP GP in the event such an exchange is required, the value of the investments we make with the cash or the common units may not over time be equivalent to the value of the general partner interest and the incentive distribution rights had MEMP GP retained them.

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

We have a substantial amount of indebtedness. As of December 31, 2014, we had aggregate indebtedness of approximately $783 million at the MRD Segment. The terms and conditions governing our indebtedness:

- require us to dedicate a substantial portion of our cash flow from operations to service our existing debt, thereby reducing the cash available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate;
- increase our vulnerability to economic downturns and adverse developments in our business;

limit our ability to access the capital markets to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness;

place restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;

place us at a competitive disadvantage relative to competitors with lower levels of indebtedness in relation to their overall size or less restrictive terms governing their indebtedness; and

limit management's discretion in operating our business.

Our ability to meet our expenses and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will not be able to control many of these factors, such as economic conditions and governmental regulation. We cannot be certain that our cash flow will be sufficient to allow us to pay the principal and interest on our debt and meet our other obligations. If we do not have enough money, we may be required to refinance all or part of our existing debt, sell assets, borrow more money or raise equity. We may not be able to refinance our debt, sell assets, borrow more money or raise equity on terms acceptable to us, if at all. For example, our existing and future debt agreements will require that we satisfy certain conditions, including coverage and leverage ratios, to borrow money. Our existing and future debt agreements will also restrict the payment of dividends and distributions by certain of our subsidiaries to us, which could affect our access to cash. In addition, our ability to comply with the financial and other restrictive covenants in our indebtedness will be affected by the levels of cash flow from our operations and future events and circumstances beyond our control. Failure to comply with these covenants would result in an event of default under our indebtedness, and such an event of default could adversely affect our business, financial condition and results of operations.

We may not be able to generate enough cash flow to meet our debt obligations and may be forced to take other actions to satisfy our debt obligations that may not be successful.

We expect our earnings and cash flow to vary significantly from year to year due to the cyclical nature of our industry. As a result, the amount of debt that we can service in some periods may not be appropriate for us in other periods. Moreover, and subject to certain limitations, we and our subsidiaries may be able to incur substantial additional indebtedness in the future. Additionally, our future cash flow may be insufficient to meet our debt obligations and commitments. Any insufficiency could negatively impact our business. A range of economic, competitive, business and industry factors will affect our future financial performance, and, as a result, our ability to generate cash flow from operations and from our subsidiaries and to pay our debt. Many of these factors, such as oil and natural gas prices, economic and financial conditions in our industry and the global economy or competitive initiatives of our competitors, are beyond our control.

If we do not generate enough cash flow from operations and from our subsidiaries to satisfy our debt obligations, we may have to undertake alternative financing plans, such as:

refinancing or restructuring our debt;

selling assets;

reducing or delaying capital investments; or

seeking to raise additional capital.

However, we cannot assure you that undertaking alternative financing plans, if necessary, would allow us to meet our debt obligations. Our inability to generate sufficient cash flow to satisfy our debt obligations or to obtain alternative financing, could materially and adversely affect our ability to make payments on our indebtedness and our business, financial condition and results of operations.

Furthermore, our ability to restructure or refinance our indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. The terms of existing or future debt instruments, including our revolving credit facility, may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on our 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 our debt service and other obligations. Our existing debt instruments currently restrict, and we expect our revolving credit facility will restrict, 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 our scheduled debt service obligations.

Our business could be adversely affected by security threats, including cyber-security threats, and related disruptions.

We rely heavily on our information systems, and the availability and integrity of these systems are essential for us to conduct our business and operations. As a producer of natural gas and oil, we face various security threats, including cyber-security threats, to gain unauthorized access to our sensitive information or to render our information or systems unusable, and threats to the security of our facilities and infrastructure or third-party facilities and infrastructure, such as gathering and processing and other facilities, refineries and pipelines. The potential for such security threats subjects our operations to increased risks that could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our implementation of various procedures and controls to monitor and mitigate such security threats and to increase security for our information, systems, facilities and infrastructure may result in increased costs. Moreover, there can be no assurance that such procedures and controls will be sufficient to prevent security breaches from occurring. If any of these security breaches were to occur, they could lead to losses of, or damage to, sensitive information or facilities, infrastructure and systems essential to our business and operations, as well as data corruption, communication interruptions or other disruptions to our operations, which, in turn, could have a material adverse effect on our business, financial position, results of operations and cash flows.

Risks Relating to Our Common Stock

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

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

NGP has the ability to direct the voting of more than a majority of our common stock, and its interests may conflict with those of our other stockholders.

NGP, through the Funds, beneficially owns all of the voting interests in MRD Holdco. MRD Holdco owns in the aggregate approximately 38% of the combined voting power of our common stock. MRD Holdco and certain former management members of WildHorse Resources, who own in the aggregate approximately 17% of the combined voting power of our common stock, are party to a voting agreement, pursuant to which the former management members of WildHorse Resources agree, among other things, to vote all of their shares as directed by MRD Holdco. As a result, MRD Holdco and, thus, NGP are able to control matters requiring stockholder approval, including the election of directors, changes to our organizational documents and significant corporate transactions. This concentration of ownership makes it unlikely that any other holder or group of holders of our common stock will be able to affect the way we are managed or the direction of our business. The interests of NGP with respect to matters potentially or actually involving or affecting us, such as future acquisitions, financings and other corporate opportunities and attempts to acquire us, may conflict with the interests of our other stockholders. Given this concentrated ownership, NGP would have to approve any potential acquisition of us. In addition, certain of our directors are currently employees of NGP. These directors’ duties as employees of NGP may conflict with their duties as our directors, and the resolution of these conflicts may not always be in our or your best interest.

Many of the directors and all of the officers who have responsibility for our management have significant duties with, and spend significant time serving, entities that may compete with us in seeking acquisitions and business opportunities and, accordingly, may have conflicts of interest in allocating time or pursuing business opportunities.

Most of our officers hold similar positions with MRD Holdco and MEMP GP, and many of our directors, who are responsible for managing the direction of our operations and acquisition activities, hold positions of responsibility with other entities (including NGP-affiliated entities) that are in the business of identifying and acquiring oil and natural gas properties. For example, the Funds and their affiliates (including NGP) are in the business of investing in oil and natural gas companies with independent management teams that also seek to acquire oil and natural gas properties, and MRD Holdco and MEMP are both in the business of acquiring and developing oil and natural gas properties. Mr. Hersh, one of our directors, is a managing partner of NGP; Mr. Gieselman, one of our directors, is a managing director of NGP; Mr. Weber, one of our directors, is a managing partner of NGP and serves as Chief Operating Officer for NGP; and Mr. Weinzierl, our Chief Executive Officer and one of our directors, is the Chief Executive Officer and Chairman of MEMP GP, and was a managing director and operating partner of NGP and continues to hold ownership interests in the Funds and certain of their affiliates. Our officers, most of whom hold MRD Holdco incentive units, will continue to devote significant time to the business of MEMP and MRD Holdco and face conflicts in allocating their time on our behalf and on behalf of MEMP GP and MRD Holdco. Our officers have also historically received a significant portion of their overall compensation in MEMP unit awards under the long term incentive plan of MEMP GP. We cannot assure you that any conflicts that may arise between us and our stockholders, on the one hand, and MRD Holdco, MEMP, or the Funds, on the other hand, will be resolved in our favor. The existing positions held by these directors and officers may give rise to fiduciary or other duties that are in conflict with the duties they owe to us. These officers and directors may become aware of business opportunities that may be appropriate for presentation to us as well as to the other entities with which they are or may become affiliated. Due to these existing and potential future affiliations, they may present potential business opportunities to other entities prior to presenting them to us, which could cause additional conflicts of interest. They may also decide that certain opportunities are more appropriate for other entities with which they are affiliated, and as a result, they may elect not to present those opportunities to us. These conflicts may not be resolved in our favor.

The corporate opportunity provisions in our amended and restated certificate of incorporation could enable NGP, MRD Holdco or the Funds to benefit from corporate opportunities that might otherwise be available to us.

Subject to the limitations of applicable law, our amended and restated certificate of incorporation, among other things:

- permits any of NGP, MRD Holdco, the Funds, their respective affiliates, or our officers or directors to conduct business that competes with us and to make investments in any kind of property in which we may make investments; and
- provides that if NGP, MRD Holdco, the Funds or their respective affiliates or any director or officer of one of our affiliates, NGP, MRD Holdco, the Funds or their respective affiliates who is also one of our officers or directors becomes aware of a potential business opportunity, transaction or other matter, they will have no duty to communicate or offer that opportunity to us.

As a result, NGP, MRD Holdco, the Funds or their affiliates may become aware, from time to time, of certain business opportunities (such as acquisition opportunities) and may direct such opportunities to other businesses in which they have invested, in which case we may not become aware of or otherwise have the ability to pursue such opportunity. Further, such businesses may choose to compete with us for these opportunities. As a result, our renouncing our interest and expectancy in any business opportunity that may be from time to time presented to NGP, MRD Holdco or the Funds and their affiliates could adversely impact our business or prospects if attractive business opportunities are procured by such parties for their own benefit rather than for ours.

We are a “controlled company” within the meaning of the NASDAQ rules and, as a result, qualify for, and rely on, exemptions from certain corporate governance requirements.

MRD Holdco and certain former management members of WildHorse Resources, as a group, control a majority of our voting common stock. As a result, we are a "controlled company" within the meaning of applicable corporate governance standards. Under the NASDAQ rules, a company of which more than 50% of the voting power is held by an individual, group or another company is a "controlled company" and may elect not to comply with certain corporate governance requirements, including:

- the requirement that we have a majority of independent directors on our Board;
- the requirement that we have a nominating committee that is composed entirely of independent directors with a written charter addressing the committee's purpose and responsibilities;
- the requirement that we have a compensation committee that is composed entirely of independent directors; and
- the requirement for an annual performance evaluation of the nominating and compensation committees.

We utilize the foregoing exemptions from the applicable corporate governance requirements. As a result, we do not have a majority of independent directors and do not have a compensation committee. Accordingly, you will not have the same protections afforded to stockholders of companies that are subject to all of the applicable corporate governance requirements.

The price of our common stock may fluctuate significantly and you could lose all or part of your investment.

Volatility in the market price of our common stock may prevent you from being able to sell your common stock at or above the price you paid for your common stock. The market price for our common stock could fluctuate significantly for various reasons, including:

- our operating and financial performance and prospects;
- changes in earnings estimates or recommendations by securities analysts who track our common stock or industry;
- market and industry perception of our success, or lack thereof, in pursuing our growth strategy; and
- sales of common stock by us, our stockholders (including the Funds), or members of our management team.

In addition, the stock market has experienced significant price and volume fluctuations in recent years. This volatility has had a significant impact on the market price of securities issued by many companies, including companies in our industries. The changes frequently appear to occur without regard to the operating performance of the affected companies. Hence, the price of our common stock could fluctuate based upon factors that have little or nothing to do with us, and these fluctuations could materially reduce our share price.

We currently have no plans to pay regular dividends on our common stock, so you may not receive funds without selling your common stock.

We currently have no plans to pay regular dividends on our common stock. Any payment of dividends in the future will be at the discretion of our Board and will depend on, among other things, our earnings, financial condition and business opportunities, the restrictions in our debt agreements, and other considerations that our Board deems relevant. Accordingly, you may have to sell some or all of your common stock in order to generate cash flow from your investment.

Future sales or the possibility of future sales of a substantial amount of our common stock may depress the price of shares of our common stock and any additional capital raised by us through the sale of equity securities or convertible securities may dilute your ownership in us.

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

MRD Holdco and certain former management members of WildHorse Resources are party to the Registration Rights Agreement, which requires us to effect the registration of their shares in certain circumstances. Upon the effectiveness of such a registration statement, all shares covered by the registration statement would be freely transferable without restriction or further registration under the Securities Act, except for any such shares which are acquired by any of our "affiliates" as that term is defined in Rule 144 under the Securities Act, which will be subject to the resale limitations of Rule 144.

We filed a registration statement with the SEC on Form S-8 providing for the registration of 19,250,000 shares of our common stock issued or reserved for issuance under our Memorial Resource Development Corp. 2014 Long Term Incentive Plan. Subject to the satisfaction of vesting conditions and the expiration of lock-up agreements, shares registered under our registration statement on Form S-8 are available for resale immediately in the public market without restriction.

Our organizational documents and the voting agreement may impede or discourage a takeover, which could deprive our investors of the opportunity to receive a premium for their shares.

Provisions of our amended and restated certificate of incorporation, our amended and restated bylaws and the voting agreement may make it more difficult for, or prevent a third party from, acquiring control of us. These provisions include:

- requiring that certain former management members of WildHorse Resources vote all of their shares of our common stock, including with respect to the election of our directors, as directed by MRD Holdco;

at such time MRD Holdco, NGP or as the Funds no longer beneficially own or control the voting of more than 50% of our outstanding common stock, our Board will be divided into three classes with each class serving staggered three year terms;
at such time MRD Holdco, NGP or as the Funds no longer beneficially own or control the voting of more than 50% of our outstanding common stock, any action by stockholders may only be taken at an annual meeting or special meeting and may no longer be effected by a written consent of the stockholders, subject to the rights of any series of preferred stock with respect to such rights;
at such time as MRD Holdco, NGP or the Funds no longer beneficially own or control the voting of more than 50% of our outstanding common stock, special meetings of our stockholders may only be called by our Board pursuant to a resolution adopted by the affirmative vote of a majority of the total number of authorized directors whether or not there exist any vacancies in previously authorized directorships (prior to such time, a special meeting may also be called at the request of stockholders holding a majority of the outstanding shares entitled to vote);
at such time as MRD Holdco, NGP or the Funds no longer beneficially own or control the voting of more than 50% of our outstanding common stock, the affirmative vote of the holders of at least 75% in voting power of all then outstanding common stock entitled to vote generally in the election of directors, voting together as a single class, shall be required to remove any or all of the directors from office at any time;
prohibiting cumulative voting in the election of directors; and
authorizing the issuance of “blank check” preferred stock without any need for action by stockholders.
Our issuance of shares of preferred stock could delay or prevent a change in control of us. Our Board has authority to issue shares of preferred stock without stockholder approval in one or more series, designate the number of shares constituting any series, and fix the rights, preferences, privileges and restrictions thereof, including dividend rights, voting rights, rights and terms of redemption, redemption price or prices and liquidation preferences of such series. The issuance of shares of our preferred stock may have the effect of delaying, deferring or preventing a change in control without further action by the stockholders, even where stockholders are offered a premium for their shares.

Together, our amended and restated certificate of incorporation, amended and restated bylaws and the voting agreement could make the removal of management more difficult and may discourage transactions that otherwise could involve payment of a premium over prevailing market prices for our common stock. Furthermore, the existence of the foregoing provisions, as well as the significant amount of common stock beneficially owned by the Funds, could limit the price that investors might be willing to pay in the future for shares of our common stock. They could also deter potential acquirers of us, thereby reducing the likelihood that you could receive a premium for your common stock in an acquisition.

We have engaged in transactions with our affiliates and expect to do so in the future. The terms of such transactions and the resolution of any conflicts that may arise may not always be in our or our stockholders’ best interests.

We have engaged in transactions and expect to continue to engage in transactions with affiliated companies. The resolution of any conflicts that may arise in connection with any related party transactions that we have entered into with MEMP, NGP, MRD Holdco, the Funds or their affiliates, including pricing, duration or other terms of service, may not always be in our or our stockholders’ best interests because NGP or the Funds may have the ability to influence the outcome of these conflicts. For a discussion of potential conflicts, please read “—NGP has the ability to direct the voting of more than a majority of our common stock, and its interests may conflict with those of our other stockholders.”

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

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

The additional requirements of having a class of publicly traded equity securities may strain our resources and distract management.

As a public company, we are subject to additional reporting requirements of the Exchange Act, the Sarbanes-Oxley Act of 2002 and the Dodd-Frank Act. The Dodd-Frank Act effects comprehensive changes to public company governance and disclosures in the United States and subject to additional federal regulation. We cannot predict with any certainty the requirements of the regulations ultimately adopted or how the Dodd-Frank Act and such regulations will impact the cost of compliance for a company with publicly traded common stock. We are currently evaluating and monitoring developments with respect to the Dodd-Frank Act and other new and proposed rules and cannot predict or estimate the amount of the additional costs we may incur or the timing of such costs. These laws, regulations and standards are subject to varying interpretations, in many cases due to their lack of specificity, and, as a result, their application in practice may evolve over time as new guidance is provided by regulatory and governing bodies. This could result in continuing uncertainty regarding compliance matters and higher costs necessitated by ongoing revisions to disclosure and governance practices. We intend to invest resources to comply with evolving laws, regulations and standards, and this investment may result in increased general and administrative expenses and a diversion of management’s time and attention from revenue-generating activities to compliance activities. If our efforts to comply with new laws, regulations and standards differ from the activities intended by regulatory or governing bodies due to ambiguities related to practice, regulatory authorities may initiate legal proceedings against us and our business may be harmed. As a company with publicly traded common stock, these new rules and regulations may make it more expensive for us to obtain director and officer liability insurance, and we may be required to accept reduced coverage or incur substantially higher costs to obtain coverage. These factors could also make it more difficult for us to attract and retain qualified members of our Board, particularly to serve on our audit committee, and qualified executive officers.

The Sarbanes-Oxley Act requires that we maintain effective disclosure controls and procedures and internal control over financial reporting. These requirements may place a strain on our systems and resources. Under Section 404 of the Sarbanes-Oxley Act, we are required to include a report of management on our internal control over financial reporting in our Annual Reports on Form 10-K beginning with the Form 10-K for the year ending December 31, 2015. In order to maintain and improve the effectiveness of our disclosure controls and procedures and internal control over financial reporting, significant resources and management oversight are required. This may divert management’s attention from other business concerns, which could have a material adverse effect on our business, financial condition, results of operations and cash flows. If we are unable to conclude that our disclosure controls and procedures and internal control over financial reporting are effective, or if we are no longer an emerging growth company and our independent public accounting firm is unable to provide us with an unqualified report on our internal control over financial reporting in future years, investors may lose confidence in our financial reports and our stock price may decline.

We may remain an “emerging growth company” for up to five years. After we are no longer an “emerging growth company,” we expect to incur significant additional expenses and devote substantial management effort toward ensuring compliance with those requirements applicable to companies that are not “emerging growth companies,” including Section 404 of the Sarbanes-Oxley Act.

We are an “emerging growth company” and we cannot be certain if the reduced disclosure requirements applicable to emerging growth companies will make our common stock less attractive to investors.

We are an “emerging growth company,” as defined in the JOBS Act, and we currently take advantage of certain exemptions from various reporting requirements that are applicable to other public companies, including, but not limited to, not being required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act, reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements, and exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and stockholder approval of any golden parachute payments not previously approved. We intend to take advantage of these reporting exemptions until we are no longer an “emerging growth company.” We cannot predict if investors will find our common stock less attractive because we rely and will continue to rely on these exemptions. If some investors find our common stock less attractive as a result, there may be a less active trading market for our common stock and our stock price may be more volatile. We will cease to be an “emerging growth company” upon the earliest of (i) the last day of the fiscal year in which we have $1.0 billion or more in annual revenues, (ii) the date on which we become a “large accelerated filer” (the fiscal year-end on which the total market value of our common equity securities held by non-affiliates is $700 million or more as of June 30), (iii) the date on which we issue more than $1.0 billion of non-convertible debt over a three-year period, or (iv) the last day of the fiscal year following the fifth anniversary of our initial public offering.

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

To the extent that we rely on any of the exemptions available to emerging growth companies, you will receive less information about our executive compensation and internal control over financial reporting than issuers that are not emerging growth companies. If some investors find our common stock to be less attractive as a result, there may be a less active trading market for our common stock and our stock price may be more volatile.

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

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

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

Information regarding our properties is contained in Item 1. “Our Operations” and “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations —Results of Operations” contained herein.

ITEM 3. LEGAL PROCEEDINGS

As part of our normal business activities, we may be named as defendants in litigation and legal proceedings, including those arising from regulatory and environmental matters. If we determine that a negative outcome is probable and the amount of loss is reasonably estimable, we accrue the estimated amount. We are not aware of any litigation, pending or threatened, that we believe will have a material adverse effect on our financial position, results of operations or cash flows. No amounts have been accrued at December 31, 2014.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Market Information

Our common stock began trading on the NASDAQ Global Market under the symbol “MRD” on June 13, 2014. Prior to that, there was no public market for our common stock. As of March 1, 2015, we had approximately 191,757,539 shares of common stock outstanding and 81 stockholders of record. The following table sets forth, for the periods indicated, the reported high and low sale prices for our common stock on the NASDAQ Global Market.

	Common Share Price Range	
	High	Low
2014		
4th Quarter	$28.44	$15.30

3rd Quarter	$30.32	$22.50
2nd Quarter (beginning June 13, 2014)	$25.90	$21.07
1st Quarter	n/a	n/a

Dividend Policy

We do not anticipate declaring or providing any cash dividends to holders of our common stock in the foreseeable future. We currently intend to retain all future earnings, if any, for use in the operation of our business and to fund future growth. The decision whether to pay dividends in the future will be made by our Board in light of conditions then existing, including factors such as our financial condition, earnings, available cash, business opportunities, legal requirements, restrictions in our debt agreements, and other contracts and other factors our Board deems relevant.

Securities Authorized for Issuance Under Equity Compensation Plans

The following table summarizes information about our equity compensation plans as of December 31, 2014:

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans
Equity compensation plans not approved by security holders (1):			
Long-Term Incentive Plan	—	—	18,190,789

(1) The Memorial Resource Development Corp. 2014 Long-Term Incentive Plan was adopted in June 2014 in connection with the completion of our initial public offering.

Issuer Purchases of Equity Securities

The following table summarizes our common share repurchase program that was authorized by the Board as of December 31, 2014:

Period	Total Number of Shares Purchased	Average Price Paid per Shares	Total Number of Shares Purchased as Part of Publicly Announced Plan	Approximate Dollar Value of Shares That May Yet Be Purchased Under the Plan
				(in thousands)
Repurchase Program (1)				
October 1, 2014 - October 31, 2014	—	$ —	—	—
November 1, 2014 - November 30, 2014	—	$ —	—	—
December 1, 2014 - December 31, 2014	123,797	$ 17.90	123,797	47,784

(1) Represents common shares repurchased and retired under our share repurchase program. See “--2014 Developments” contained in “Part I-- Item 1. Business” for additional information.

Comparative Stock Performance

The following stock price performance graph is intended to allow review of stockholder returns, expressed in terms of the appreciation of the Company’s common stock relative to two broad-based stock performance indices. The information is included for historical comparative purposes only and should not be considered indicative of future stock performance. The stock performance graph and related information shall not be deemed “soliciting material” or to be “filed” with the SEC, nor shall information be incorporated by reference into any future filing under the Securities Act or Exchange Act, except to the extent that the Company specifically incorporates it by reference into such filing.

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The performance graph shown below compares the total return to stockholders on MRD's common stock as compared to the total returns on the Standard and Poor's 500 Index ("S&P 500 Index") and the Standard and Poor's 500 Oil and Gas Exploration and Production Select Index ("S&P Oil and Gas E&P Select Index") from June 12, 2014, through December 31, 2014. The comparison was prepared based upon the following assumptions:

1. $100 was invested on June 12, 2014 in each of the following: common stock of MRD, the S&P 500 Index and the S&P Oil and Gas E&P Select Index.
2. Dividends are reinvested.

	June 12, 2014	September 30, 2014	December 31, 2014
MRD	$ 100.00	$ 142.68	$ 94.89
S&P 500 Index	$ 100.00	$ 86.64	$ 60.50
S&P Oil and Gas E&P Select Index	$ 100.00	$ 102.77	$ 107.83

ITEM 6. SELECTED FINANCIAL DATA

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

Basis of Presentation. The selected financial data as of, and for the years ended, December 31, 2014, 2013, and 2012 presented below have been derived from our consolidated financial statements and our predecessor and the previous owners on a combined basis for periods prior to our initial public offering. For periods after the completion of our public offering, our consolidated financial statements include our accounts and those of our subsidiaries in which we have a controlling interest. Due to our control of MEMP through our ownership of MEMP GP, we are required to consolidate MEMP for accounting and financial reporting purposes. MEMP is owned 99.9% by its limited partners and 0.1% by MEMP GP.

Comparability of the information reflected in selected financial data. The comparability of the results of operations among the periods presented is impacted by the following significant transactions:

- the acquisition of working interests, royalty interests and net revenue interests located in the Permian Basin in July 2012 for a net purchase price of approximately $74.7 million;
- two separate third party acquisitions by MEMP of assets in East Texas in May and September 2012, respectively, for a combined net purchase price of approximately $126.9 million;
- multiple acquisitions of operated and non-operated interests in certain oil and natural gas properties primarily located in the Permian Basin during 2013 for an aggregate net purchase price of $75.9 million;
- the acquisition by WildHorse Resources of assets in Louisiana in March 2013 for approximately $67.1 million;
- the sale of assets by BlueStone in East Texas in July 2013 for approximately $117.9 million;
- the Eagle Ford Acquisition in March 2014 for a net purchase price of $168.1 million;
- the June 2014 distribution by MRD LLC of the following to MRD Holdco: (i) BlueStone, MRD Royalty LLC, MRD Midstream LLC, Golden Energy and Classic Pipeline; and (ii) the MEMP subordinated units;
- the contribution by certain former management members of WildHorse Resources to us of their outstanding incentive units in WildHorse Resources, as well as the remaining 0.1% of the membership interests in WildHorse Resources, and the issuance of 42,334,323 shares of our common stock and payment of cash consideration of $30.0 million to such former management members of WildHorse Resources and recognition of compensation expense of $831.1 million; and
- the MEMP Wyoming Acquisition in July 2014 for a purchase price of approximately $906.1 million.

As a result of the factors listed above, the consolidated and combined historical results of operations and period-to-period comparisons of these results and certain financial data may not be comparable or indicative of future results.

	For the Year Ended December 31,		
	2014	2013	2012
	(In thousands, except per share data)		
Statement of Operations Data:			
Revenues:			
Oil & natural gas sales	$894,967	$571,948	$393,631
Other revenues	4,378	3,075	3,237
Total revenues	899,345	575,023	396,868
Costs and expenses:			
Lease operating	161,303	113,640	103,754
Pipeline operating	2,068	1,835	2,114
Exploration	16,603	2,356	9,800
Production and ad valorem taxes	45,751	27,146	23,624
Depreciation, depletion, and amortization	314,193	184,717	138,672
Impairment of proved oil and natural gas properties	432,116	6,600	28,871
Incentive unit compensation expense	943,949	43,279	9,510
General and administrative	87,673	82,079	59,677
Accretion of asset retirement obligations	6,306	5,581	5,009
(Gain) loss on commodity derivative instruments	(749,988)	(29,294)	(34,905)
(Gain) loss on sale of properties	3,057	(85,621)	(9,761)
Other, net	(12)	649	502
Total costs and expenses	1,263,019	352,967	336,867
Operating income (loss)	(363,674)	222,056	60,001
Other income (expense):			
Interest expense, net	(133,833)	(69,250)	(33,238)
Loss on extinguishment of debt	(37,248)	—	—
Amortization of investment premium	—	—	(194)
Other, net	(337)	145	535
Total other income (expense)	(171,418)	(69,105)	(32,897)
Income (loss) before income taxes	(535,092)	152,951	27,104
Income tax benefit (expense)	(100,971)	(1,619)	(107)
Net income (loss)	(636,063)	151,332	26,997
Net income (loss) attributable to noncontrolling interest	126,788	49,830	(2,701)
Net income (loss) attributable to Memorial Resource Development Corp.	(762,851)	101,502	29,698
Net (income) loss allocated to members	(20,305)	(90,712)	7,620
Net (income) loss allocated to previous owners	(1,425)	(10,790)	(37,318)
Net income (loss) available to common stockholders	$(784,581)	$—	$—
Earnings per common share:			
Basic	$(4.08)	n/a	n/a
Diluted	$(4.08)	n/a	n/a
Cash Flow Data:			
Net cash flow provided by operating activities	$476,271	$277,823	$240,404
Net cash used in investing activities	1,816,979	367,443	606,738

Net cash provided by financing activities	1,268,945	117,950	361,761
Balance Sheet Data:			
Working capital	$219,580	$48,256	$63,054
Total assets	4,593,547	2,829,161	2,459,304
Total debt	2,378,413	1,663,217	939,382
Total equity	1,702,964	858,132	1,276,709

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

Management's Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with the financial statements and related notes in "Item 8. Financial Statements and Supplementary Data" contained herein. The following discussion contains forward-looking statements that reflect our future plans, estimates, beliefs and expected performance. The forward-looking statements are dependent upon events, risks and uncertainties that may be outside our control. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences are discussed in "Risk Factors" contained in Part I—Item 1A of this report. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See "Forward-Looking Statements" in the front of this report.

Overview

We are a Delaware corporation, formed by Memorial Resource Development LLC ("MRD LLC") in January 2014, engaged in the acquisition, exploration, and development of natural gas and oil properties primarily in North Louisiana. MRD LLC, our accounting predecessor, was a Delaware limited liability company formed on April 27, 2011 by Natural Gas Partners VIII, L.P. ("NGP VIII"), Natural Gas Partners IX, L.P. ("NGP IX") and NGP IX Offshore Holdings, L.P. ("NGP IX Offshore") (collectively, the "Funds") to own, acquire, exploit and develop oil and natural gas properties. The Funds are private equity funds managed by Natural Gas Partners ("NGP").

We completed our initial public offering on June 18, 2014. In connection with the closing of our initial public offering, MRD LLC contributed to us substantially all of its assets, comprised of the following, in exchange for shares of our common stock (which were distributed to MRD LLC's sole member, MRD Holdco LLC ("MRD Holdco")): (1) 100% of its ownership interests in Classic Hydrocarbons Holdings, L.P. ("Classic"), Classic Hydrocarbons GP Co., L.L.C. ("Classic GP"), Black Diamond Minerals, LLC ("Black Diamond"), Beta Operating Company, LLC ("Beta Operating"), MRD Operating LLC ("MRD Operating") and Memorial Production Partners GP LLC ("MEMP GP"), which owns a 0.1% general partner interest and 50% of the incentive distribution rights in Memorial Production Partners LP ("MEMP"), and (2) its 99.9% membership interest in WildHorse Resources, LLC ("WildHorse Resources"). In addition, certain former management members of WildHorse Resources contributed to us the remaining 0.1% membership interest in WildHorse Resources, and also exchanged their incentive units in WildHorse Resources, for shares of our common stock and cash consideration. As a result, we are majority-owned by the group consisting of MRD Holdco and certain former management members of WildHorse Resources.

Following the completion of our initial public offering, MRD LLC distributed to MRD Holdco (i) its interests in BlueStone Natural Resources Holdings, LLC ("BlueStone"), MRD Royalty LLC ("MRD Royalty"), MRD Midstream LLC ("MRD Midstream"), Golden Energy Partners LLC ("Golden Energy") and Classic Pipeline & Gathering, LLC ("Classic Pipeline"), (ii) the MEMP subordinated units (which converted to common units on February 13, 2015); (iii) the remaining cash released from its debt service reserve account in connection with the redemption of the 10.00% /10.75% Senior PIK Toggle Notes due 2018 (the "PIK notes"); and (iv) approximately $6.7 million of cash received by MRD LLC in connection with the sale of Golden Energy's assets in May 2014. We also reimbursed MRD LLC for the approximately $17.2 million interest payment that it made on the PIK notes on June 15, 2014, which was distributed to MRD Holdco.

As part of the restructuring transactions, we merged Black Diamond into MRD Operating in connection with the completion of our initial public offering, and MRD LLC was merged into MRD Operating upon the termination of the PIK notes indenture on June 27, 2014. WildHorse Resources merged into MRD Operating in February 2015.

We control MEMP through the ownership of MEMP GP. MEMP is a publicly traded limited partnership engaged in the acquisition, production and development of oil and natural gas properties in the United States. Due to our control of MEMP through the ownership of MEMP GP, we are required to consolidate MEMP for accounting and financial reporting purposes. Although consolidated for accounting and financial reporting, we each have independent capital structures. We will receive cash distributions from MEMP as a result of MEMP GP's 0.1% general partner interest and incentive distribution rights in MEMP, when declared and paid by MEMP.

Business Segments

Our reportable business segments are organized in a manner that reflects how management manages those business activities. We evaluate segment performance based on Adjusted EBITDA. The definition and calculation of Adjusted EBITDA and the reconciliation of total reportable segments' Adjusted EBITDA to net income (loss) is included in the notes to our consolidated and combined financial statements found under "Item 8. Financial Statements and Supplementary Data," contained herein. Adjusted EBITDA (either in total or by individual segment) is an important performance measure of the core profitability of our operations. This measure forms the basis of our internal financial reporting and is used by our management in evaluating segment performance. We believe that investors benefit from having access to the same financial measures that our management uses in evaluating segment results. Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income (loss). Our computation of Adjusted EBITDA may not be comparable to similarly titled measures of other companies. We believe that Adjusted EBITDA is a widely followed measure of operating performance and may also be used by investors to measure our ability to meet debt service requirements.

We have two reportable business segments, both of which are engaged in the acquisition, exploration, development and production of oil and natural gas properties. Our reportable business segments are as follows:

MRD—reflects the combined operations of the Company, MRD Operating, MRD LLC, WildHorse Resources and its previous owners, Classic and Classic GP, Black Diamond, BlueStone, Beta Operating and MEMP GP.
MEMP—reflects the combined operations of MEMP, its previous owners, and certain historical dropdown transactions that occurred between MEMP and other MRD LLC consolidating subsidiaries.

Segment financial information has been retrospectively revised for the following common control transactions between MEMP and MRD LLC for comparability purposes:

acquisition by MEMP of all the outstanding membership interests in Tanos Energy, LLC ("Tanos") for a purchase price of approximately $77.4 million in October 2013;
acquisition by MEMP of all the outstanding membership interests in Prospect Energy, LLC ("Prospect Energy") from Black Diamond for a purchase price of approximately $16.3 million in October 2013;
acquisition by MEMP of certain of the oil and natural gas properties in Jackson County, Texas from MRD LLC for a purchase price of approximately $2.6 million in October 2013;
acquisition by MEMP of all the outstanding membership interests in WHT Energy Partners LLC ("WHT") for a purchase price of approximately $200.0 million in March 2013;
acquisition by MEMP of certain assets from Classic in East Texas in May 2012 for a purchase price of approximately $27.0 million; and
acquisition by MEMP of certain assets from Tanos in East Texas in April 2012 for a purchase price of approximately $18.5 million.

The MRD Segment is focused on the acquisition, exploration, and development of natural gas and oil properties primarily in the Cotton Valley formation in North Louisiana. These properties consist primarily of assets with extensive production histories, high drilling success rates, and significant horizontal redevelopment potential. The MRD Segment is focused on maintaining and growing its production and cash flow primarily through the development of its sizeable inventory. The MRD Segment, prior to our initial public offering, included BlueStone, MRD Royalty, MRD Midstream, Golden Energy, Classic Pipeline, the MEMP subordinated units and cash held in a debt service reserve account that had been established when the PIK notes were issued in December 2013.

The MEMP Segment is engaged in the acquisition, exploitation, development and production of oil and natural gas properties, with assets consisting primarily of producing oil and natural gas properties that are located in Texas, Louisiana, Colorado, Wyoming, and New Mexico and offshore Southern California. Most of the MEMP Segment's properties are located in large, mature oil and natural gas reservoirs with well-known geologic characteristics and long-lived, predictable production profiles and modest capital requirements. The MEMP Segment is focused on generating stable cash flows to allow MEMP to make quarterly cash distributions to its unitholders and, over time, to increase those quarterly cash distributions.

Outlook

The continuation of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and our access to capital. Although we cannot predict the occurrence of events or factors that will affect future commodity prices, such as the supply of, and demand for, oil, natural gas, and NGLs, and general domestic or foreign economic conditions and political developments, or the degree to which these prices will be affected, the prices for any oil, natural gas or NGLs that we produce will generally approximate market prices in the geographic region of the production.

Oil prices declined significantly in the second half of 2014 and have continued to drop in early 2015. This decline in oil prices stems in large part from decreased demand due to weak economic activity and increased efficiency, an excess of supply due to sustained high output from North America, and the Organization of Petroleum Exporting Countries failure to reach agreement on production curbs in November 2014.

The U.S. Energy Information Administration, or EIA, forecasts that Brent crude oil prices will average $58 per Bbl in 2015 and $75 per Bbl in 2016. North Sea Brent crude oil spot prices averaged $62 per Bbl in December 2014, the lowest monthly average Brent price since May 2009, down $17 per Bbl from the November average. The combination of robust world crude oil supply growth and weak global demand has contributed to rising global inventories and falling crude oil prices. The EIA expects global oil inventories to continue to build in 2015, keeping downward pressure on oil prices. Like Brent crude oil prices, WTI prices have decreased considerably, with monthly average prices falling by more than 44% as of December 2014 after reaching their 2014 peak of $106 per Bbl in June. The EIA expects WTI crude oil prices to average $55 per Bbl in 2015 and $71 per Bbl in 2016.

The EIA expects the Henry Hub natural gas spot price to average $3.52 per MMBtu this winter compared with $4.51 per MMBtu last winter, reflecting both lower-than-expected space heating demand and higher natural gas production this winter. The EIA expects the Henry Hub natural gas spot price to average $3.44 per MMBtu in 2015 and $3.86 per MMBtu in 2016, compared with $4.39 per MMBtu in 2014. The EIA expects monthly average spot prices to remain less than $4 per MMBtu until the fourth quarter of 2016.

Commodity hedging remains an important part of our strategy to reduce cash flow volatility. Our hedging activities are intended to support oil and natural gas prices at targeted levels and to manage our exposure to oil and natural gas price fluctuations. See “Item 7A. Quantitative and Qualitative Disclosures About Market Risk” for additional information.

We expect our 2015 development program and capital budget will be focused on the Terryville Complex, where we plan to allocate approximately 100% of our drilling and completion capital budget, primarily targeting our four primary zones within the Cotton Valley— the Upper Red, Lower Red, Lower Deep Pink and Upper Deep Pink. We expect to fund our 2015 development primarily from cash flows from operations and borrowings under our revolving credit facility. However, there can be no assurance that our operations or other capital resources will provide cash in amounts that are sufficient to maintain our planned levels of capital expenditures.

Sources of Revenues

Both our and MEMP’s revenues are derived from the sale of natural gas and oil production, as well as the sale of NGLs that are extracted from natural gas during processing. Production revenues are derived entirely from the continental United States. Natural gas, NGL and oil prices are inherently volatile and are influenced by many factors outside our control. In order to reduce the impact of fluctuations in natural gas and oil prices on revenues, or to protect the economics of property acquisitions, both we and MEMP intend to periodically enter into derivative contracts with respect to a significant portion of estimated natural gas and oil production through various transactions that fix the future prices received. At the end of each period the fair value of these commodity derivative instruments are estimated and, because hedge accounting is not elected, the changes in the fair value of unsettled commodity derivative instruments are recognized in earnings at the end of each accounting period.

Principal Components of Cost Structure

Lease operating expenses. These are the day to day costs incurred to maintain production of our natural gas, NGLs and oil. Such costs include utilities, direct labor, water injection and disposal, materials and supplies, compression, repairs and workover expenses. Cost levels for these expenses can vary based on supply and demand for oilfield services.

Production and ad valorem taxes. These consist of severance and ad valorem taxes. Production taxes are paid on produced natural gas, NGLs and oil based on a percentage of market prices and at fixed per unit rates established by federal, state or local taxing authorities. Both we and MEMP take full advantage of all credits and exemptions in the various taxing jurisdictions where we operate. Ad valorem taxes are generally tied to the valuation of the oil and natural properties; however, these valuations are reasonably correlated to revenues, excluding the effects of any commodity derivative contracts.

Exploration expense. These are geological and geophysical costs and include seismic costs, costs of unsuccessful exploratory dry holes and unsuccessful leasing efforts.

Impairment of proved properties. Proved properties are impaired whenever the carrying value of the properties exceed their estimated undiscounted future cash flows.

Depreciation, depletion and amortization. Depreciation, depletion and amortization, or DD&A, includes the systematic expensing of the capitalized costs incurred to acquire, exploit and develop natural gas and oil properties. As a “successful efforts” company, all costs associated with acquisition and development efforts and all successful exploration efforts are capitalized, and these costs are depleted using the units of production method.

Incentive unit compensation expense. For more information regarding compensation expense recognized associated with incentive units, see Note 12 of the Notes to Consolidated and Combined Financial Statements under “Item 8. Financial Statements and Supplementary Data,” contained herein.

General and administrative expense. These costs include overhead, including payroll and benefits for employees, costs of maintaining headquarters, costs of managing production and development operations, compensation expense associated with certain long-term incentive-based plans, franchise taxes, audit and other professional fees, and legal compliance expenses.

Interest expense. We and MEMP finance a portion of our working capital requirements and acquisitions with borrowings under revolving credit facilities and senior note issuances. As a result, we and MEMP incur substantial interest expense that is affected by both fluctuations in interest rates and financing decisions. We expect to continue to incur significant interest expense as we continue to grow.

Income tax expense. Prior to our initial public offering, MRD LLC was organized as a pass-through entity for federal income tax purposes and was not subject to federal income taxes; however, certain of its consolidating subsidiaries were taxed as corporations and subject to federal income taxes. We are organized as a taxable C corporation and subject to federal and certain state income taxes. We are also subject to the Texas margin tax and certain aspects of the tax make it similar to an income tax as the tax is assessed on 1% of taxable margin apportioned to operations in Texas.

Results of Operations

MRD Segment

The MRD Segment's consolidated and combined results of operations for the years ended December 31, 2014, 2013 and 2012 presented below have been derived from our predecessor's and our consolidated and combined financial statements. The comparability of the results of operations among the periods presented is impacted by the following significant transactions:

- the sale of assets by BlueStone in East Texas in July 2013 for approximately $117.9 million;
- the acquisition by WildHorse Resources of assets in Louisiana in March 2013 for approximately $67.1 million; and
- the distribution by MRD LLC of the following to MRD Holdco: (i) BlueStone, which sold substantially all of its assets in July 2013 for $117.9 million, MRD Royalty LLC, which owns certain immaterial leasehold interests and overriding royalty interests in Texas and Montana, MRD Midstream LLC, which owns an indirect interest in certain midstream assets in North Louisiana, Golden Energy and Classic Pipeline and (ii) 5,360,912 subordinated units of MEMP (which converted to common units on February 13, 2015).

Segment financial information has been retrospectively revised for material common control transactions between MEMP and MRD LLC for comparability purposes, which includes the following transactions:

- acquisition by MEMP of all the outstanding membership interests in Tanos for a purchase price of approximately $77.4 million in October 2013;
- acquisition by MEMP of all the outstanding membership interests in Prospect Energy from Black Diamond for a purchase price of approximately $16.3 million in October 2013;
- acquisition by MEMP of certain of the oil and natural gas properties in Jackson County, Texas from MRD LLC for a purchase price of approximately $2.6 million in October 2013;
- acquisition by MEMP of all the outstanding membership interests in WHT for a purchase price of approximately $200.0 million in March 2013;
- acquisition by MEMP of certain assets from Classic in East Texas in May 2012 for a purchase price of approximately $27.0 million; and
- acquisition by MEMP of certain assets from Tanos in East Texas in April 2012 for a purchase price of approximately $18.5 million.

	For the Year Ended December 31,		
	2014	2013	2012
	(in thousands)		
Oil & natural gas sales	$404,718	$230,751	$138,032
Lease operating	26,695	25,006	24,438
Exploration	15,813	1,226	7,337
Production and ad valorem taxes	14,150	9,362	7,576
Depreciation, depletion, and amortization	154,917	87,043	62,636
Impairment of proved oil and natural gas properties	24,576	2,527	18,339
Incentive unit compensation expense	943,949	43,279	9,510
General and administrative	42,054	38,479	28,904
(Gain) loss on commodity derivative instruments	(257,734)	(3,013)	(13,488)
(Gain) loss on sale of properties	3,057	(82,773)	(2)
Interest expense, net	(50,283)	(27,349)	(12,802)
Loss on extinguishment of debt	(37,248)	—	—
Income tax benefit (expense)	(99,850)	(1,311)	178
Net income (loss)	(762,926)	82,243	(14,641)
Natural gas and oil revenue:			
Oil sales	$85,150	$66,961	$35,264
NGL sales	85,730	53,881	36,611
Natural gas sales	233,838	109,909	66,157
Total natural gas and oil revenue	$404,718	$230,751	$138,032
Production Volumes:			
Oil (MBbls)	951	665	369
NGLs (MBbls)	2,220	1,457	898
Natural gas (MMcf)	63,801	34,092	24,130
Total (MMcfe)	82,815	46,819	31,731
Average net production (MMcfe/d)	226.9	128.3	86.7
Average sales price:			
Oil (per Bbl)	$89.54	$100.76	$95.56
NGL (per Bbl)	38.62	36.99	40.78
Natural gas (per Mcf)	3.67	3.22	2.74
Total (Mcfe)	$4.89	$4.93	$4.35
Average unit costs per Mcfe:			
Lease operating expense	$0.32	$0.53	$0.77
Production and ad valorem taxes	$0.17	$0.20	$0.24
General and administrative expenses	$0.51	$0.82	$0.91
Depletion, depreciation, and amortization	$1.87	$1.86	$1.97

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

The MRD Segment recorded a net loss of $762.9 million during 2014 compared to net income of $82.2 million during 2013. The net loss recorded during 2014 was primarily due to compensation expense associated with incentive units as discussed below.

Oil and natural gas revenues for 2014 totaled $404.7 million, an increase of $174.0 million compared with 2013. Production increased 36.0 Bcfe (approximately 77%) primarily due to drilling activities in North Louisiana. The average realized sales price decreased $0.04 per Mcfe primarily due to lower oil prices. The favorable volume variance contributed to an approximate $177.5 million increase and was offset by $3.5 million due to the unfavorable pricing variances.

Lease operating expenses were $26.7 million and $25.0 million for 2014 and 2013, respectively. On a per Mcfe basis, lease operating expenses decreased to $0.32 for 2014 from $0.53 for 2013. Certain items, such as direct labor and materials and supplies, generally remain relatively fixed across broad production volume ranges.

DD&A expense for 2014 was $154.9 million compared to $87.0 million for 2013, a $67.9 million increase primarily due to both an increase in the depletable cost base and increased production volumes related to drilling activities in North Louisiana. Increased production volumes caused DD&A expense to increase by an approximate $67.1 million and the change in the DD&A rate between periods caused DD&A expense to increase by an approximate $0.8 million.

Impairment expense for 2014 was $24.6 million compared to $2.5 million for 2013. The impairments primarily related to certain properties located in the Rockies and certain fields in North Louisiana. The estimated future cash flows expected from these properties were compared to their carrying values and determined to be unrecoverable primarily due to a decline in prices.

Incentive unit compensation expense for 2014 was $943.9 million, of which $831.1 million related to WildHorse Resources incentive units, $111.8 million related to MRD Holdco incentive units, and $1.0 million related to BlueStone incentive units. We recognized $43.3 million of compensation expense associated with long-term incentive plans for 2013. Incentive unit compensation expense of approximately $20.7 million was recorded by BlueStone, $10.0 million related to WildHorse Resources and $12.6 million related to the Classic and Black Diamond management buyouts in 2013. Net proceeds generated from the sale of oil and gas properties were used to pay a distribution to BlueStone incentive unit holders.

General and administrative expenses for 2014 were $42.1 million compared to $38.5 million for 2013. General and administrative expenses for 2014 included $2.3 million of acquisition-related costs. General and administrative expenses for 2013 included $1.6 million of acquisition-related costs. Increased salaries and employee headcount also contributed to increased general and administrative expenses between periods.

Net gains on commodity derivative instruments of $257.7 million were recognized during 2014, consisting of $9.2 million of cash settlement receipts in addition to a $248.5 million increase in the fair value of open hedge positions. Net gains on commodity derivative instruments of $3.0 million were recognized during 2013, consisting of $12.2 million of cash settlement receipts offset by a $9.2 million decrease in the fair value of open hedge positions.

Net interest expense during 2014 was $50.3 million, including amortization of deferred financing fees of approximately $3.2 million. Net interest expense during 2013 was $27.3 million, including amortization of deferred financing fees of approximately $2.5 million. The increase in net interest expense is primarily the result of higher level of indebtedness during 2014 compared to 2013, including the MRD Senior Notes and the PIK notes.

Average outstanding borrowings under our revolving credit facility were $111.1 million during 2014. Average outstanding borrowings under the previous owners' revolving credit facilities were $282.6 million during 2013. For the year ended December 31, 2014, we had an average of $634.5 million aggregate principal amount of the MRD Senior Notes, PIK notes and WildHorse Resources' second lien term facility issued and outstanding. For the year ended December 31, 2013, we had an average of $13.4 million aggregate principal amount of the PIK notes issued and outstanding and an average of $179.9 million aggregate principal outstanding for the WildHorse Resources' second lien term facility.

During 2014, we sold certain producing and non-producing properties in the Mississippian oil play in Northern Oklahoma to a third party and recorded a loss of $3.2 million. During 2013, BlueStone entered into an agreement with a third party to sell its remaining interest in certain properties and recognized a gain of $89.5 million. This gain was offset by a loss of $6.8 million recorded by Black Diamond on the sale of certain oil and gas properties.

An extinguishment loss of $23.6 million was recognized related to the redemption of the PIK notes. In connection with the closing of our initial public offering, WildHorse Resources' revolving credit facility and second lien term loan were repaid in full and terminated. An extinguishment loss of $13.7 million was recognized related to the termination of the revolving credit facility and second lien term loan.

We are organized as a taxable C corporation and subject to federal and certain state income taxes. We recorded tax expense of $99.9 million in 2014 subsequent to our initial public offering. Taxes recognized in 2014 related primarily to deferred items such as hedging gains and oil and natural gas property temporary differences. Prior to our initial public offering we were a flow through entity.

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

The MRD Segment recorded net income of $82.2 million in 2013 compared to a net loss of $14.6 million in 2012. The increase in net income was primarily due to gains on sales of properties and increased production.

Oil and natural gas revenues were $230.8 million in 2013, an increase of $92.7 million from 2012. Production increased 15.1 Bcfe (approximately 48%) while the average realized sales price increased $0.58 per Mcfe. Production volume increases were primarily due to acquisitions and drilling activities in the Cotton Valley formation in North Louisiana and East Texas. The favorable volume variance contributed to a $65.6 million increase in revenues, and the favorable pricing variance contributed to a $27.1 million increase in revenues.

Lease operating expenses were $25.0 million in 2013, an increase in $0.6 million from 2012. This increase was primarily due to acquisitions and drilling activities in the Cotton Valley formation in North Louisiana and East Texas. However, on a per Mcfe basis, lease operating expenses decreased by $0.24 per Mcfe as certain items, such as direct labor and materials and supplies, generally remain relatively fixed across broad production volume ranges.

The $24.4 million increase in DD&A expense was primarily due to increased production volumes related to acquisitions and drilling activities in the Cotton Valley formation in North Louisiana and East Texas. Increased production volumes increased DD&A expense by $29.8 million, while a 6% decrease in the DD&A rate between periods decreased DD&A expense by $5.4 million. On a per Mcfe basis, DD&A expense decreased by $0.11 per Mcfe from 2012 to 2013. An increase in proved reserve volumes more than offset the impact of increases to the depletable cost base.

During 2013 and 2012, the MRD Segment recorded impairments of $2.5 million and $18.3 million, respectively, primarily related to certain fields in East Texas. For these impairments, the estimated future cash flows expected from properties in these fields were compared to their carrying values and determined to be unrecoverable. Downward revisions due to performance and declines in natural gas prices triggered the 2013 and 2012 impairments, respectively.

Incentive unit compensation expense for 2013 was $43.3 million as discussed above, which related to incentive unit payments to certain key management members of certain MRD LLC subsidiaries compared to approximately $9.5 million recorded in 2012.

General and administrative expenses were $38.5 million in 2013, an increase of $9.6 million from 2012. The increase in general and administrative expenses was primarily due to growth in employees as a result of acquisitions and development activities.

Gains on commodity derivative instruments of $3.0 million were recognized during 2013, of which $12.2 million consisted of cash settlements received. Gains on commodity derivative instruments of $13.5 million were recognized during 2012, of which $30.2 million consisted of cash settlements received. The decrease in cash settlements received was primarily due to higher natural gas prices.

During 2013, BlueStone entered into an agreement with a publicly traded third party to sell its remaining interest in certain properties in the Mossy Grove Prospect in Walker and Madison Counties located in East Texas and recognized a gain of $89.5 million. This gain was offset by a loss of $6.8 million recorded by Black Diamond on the sale of certain of its Wyoming oil and gas properties. During 2012, gains of less than $0.1 million were recognized by the MRD Segment.

Net interest expense during 2013 was $27.3 million, including amortization of deferred financing fees of approximately $2.5 million and losses on interest rate swaps of $0.2 million. Net interest expense during 2012 was $12.8 million, including amortization of deferred financing fees of approximately $1.6 million and losses on interest rate swaps of $1.2 million. The increase in net interest expense is primarily the result of higher level of indebtedness during 2013 compared to 2012. Average debt outstanding was $475.9 million and $272.6 million for 2013 and 2012, respectively.

MEMP Segment

The MEMP Segment's consolidated and combined results of operations for the years ended December 31, 2014, 2013 and 2012 presented below have been derived from our consolidated and combined financial statements included under "Item 8. Financial and Supplementary Data," contained herein.

The comparability of the results of operations among the periods presented is impacted by the following significant transactions:

- two separate third party acquisitions by MEMP of assets in East Texas in May and September 2012, respectively, for a combined net purchase price of approximately $126.9 million;
- third party acquisition of working interests, royalty interests and net revenue interests located in the Permian Basin in July 2012 for a net purchase price of approximately $74.7 million;
- the 2012 divestiture of the offshore Louisiana properties by MEMP's previous owners to a related party;
- multiple third party acquisitions of operated and non-operated interests in certain oil and natural gas properties primarily located in the Permian Basin for an aggregate net purchase price of $75.9 million during 2013;
- the Eagle Ford Acquisition in March 2014 for a net purchase price of $168.1 million; and
- the MEMP Wyoming Acquisition in July 2014 for a purchase price of approximately $906.1 million.

	For the Year Ended December 31,		
	2014	2013	2012
	(in thousands)		
Oil & natural gas sales	$490,249	$341,197	$255,608
Lease operating	134,654	88,893	80,116
Exploration	790	1,130	2,463
Production and ad valorem taxes	31,601	17,784	16,048
Depreciation, depletion, and amortization	155,404	97,269	76,036
Impairment of proved oil and natural gas properties	407,540	54,362	10,532
General and administrative	45,619	43,495	30,342
(Gain) loss on commodity derivative instruments	(492,254)	(26,281)	(21,417)
(Gain) loss on sale of properties	—	(2,848)	(9,759)
Interest expense, net	(83,550)	(41,901)	(20,436)
Net income (loss)	118,079	20,268	46,518
Natural gas and oil revenue:			
Oil sales	$262,407	$171,095	$145,103
NGL sales	64,718	51,215	26,647
Natural gas sales	163,124	118,887	83,858
Total natural gas and oil revenue	$490,249	$341,197	$255,608
Production Volumes:			
Oil (MBbls)	3,092	1,764	1,519
NGLs (MBbls)	2,143	1,632	745
Natural gas (MMcf)	41,494	35,924	29,744
Total (MMcfe)	72,902	56,303	43,329
Average net production (MMcfe/d)	199.7	154.3	118.4
Average sales price:			
Oil (per Bbl)	$84.88	$96.98	$95.54
NGL(per Bbl)	30.20	31.38	35.75
Natural gas (per Mcf)	3.93	3.31	2.82

Total (Mcfe)	$6.72	$6.06	$5.90
Average unit costs per Mcfe:			
Lease operating expense	$1.85	$1.58	$1.85
Production and ad valorem taxes	$0.43	$0.32	$0.37
General and administrative expenses	$0.63	$0.77	$0.70
Depletion, depreciation, and amortization	$2.13	$1.73	$1.75

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

Net income of $118.1 million was generated for the year ended December 31, 2014, primarily due to gains on commodity derivatives offset by impairment charges. Net income of $20.3 million was generated for the year ended December 31, 2013.

Oil and natural gas sales for 2014 totaled $490.2 million, an increase of $149.1 million compared with 2013. Production increased 16.6 Bcfe (approximately 29%), primarily from volumes associated with third party acquisitions. The average realized sales price increased $0.66 per Mcfe primarily due to higher gas prices and an increase in oil volumes relative to other commodities due to MEMP's acquisitions. The favorable volume and pricing variance contributed to an approximate $100.5 million and $48.6 million increase in revenues, respectively.
Lease operating expenses were $134.7 million and $88.9 million for the year ended December 31, 2014 and 2013, respectively. In the MEMP Wyoming Acquisition, MEMP acquired more oil weighted properties, which are generally more expensive to operate compared to natural gas properties (on a per Mcfe basis). On a per Mcfe basis, lease operating expenses increased to $1.85 for 2014 from $1.58 for 2013.
Production and ad valorem taxes for 2014 totaled $31.6 million, an increase of $13.8 million compared with 2013 primarily due to an increase in production volumes and ad valorem tax rates. On a per Mcfe basis, production and ad valorem taxes increased to $0.43 for 2014 from $0.32 for 2013 due to higher production tax rates on a per Mcfe basis for MEMP's Wyoming Acquisition.
DD&A expense for 2014 was $155.4 million compared to $97.3 million for 2013, a $58.1 million increase primarily due to both an increase in the depletable cost base and increased production volumes related to third party acquisitions and MEMP's drilling program. Increased production volumes caused DD&A expense to increase by an approximate $28.7 million and the change in the DD&A rate between periods caused DD&A expense to increase by an approximate $29.4 million.
MEMP recognized $407.5 million of impairments in 2014 related primarily to certain properties in the Permian Basin, East Texas, and South Texas. The estimated future cash flows expected from these properties were compared to their carrying values and determined to be unrecoverable as a result of a downward revision of estimated proved reserves as a result of declining commodity prices and updated well performance data. During 2013, MEMP recorded $54.4 million of impairments consisting of $50.3 million related to certain properties in East Texas and $4.1 million related to certain properties in South Texas. For the East Texas properties, the estimated future cash flows expected from these properties were compared to their carrying values and determined to be unrecoverable as a result of a downward revision of estimated proved reserves based on updated well performance data. In South Texas, the estimated future cash flows expected these properties were compared to their carrying values and determined to be unrecoverable as a result of a downward revision of estimated proved reserves based on pricing terms specific to these properties.
In 2013, there was a $50.3 million impairment elimination as certain fields in East Texas noted above were not impaired on a consolidated basis.

General and administrative expenses for 2014 were $45.6 million and included $7.9 million of non-cash unit-based compensation expense and $4.4 million of acquisition-related costs. General and administrative expenses for 2013 totaled $43.5 million and included $3.6 million of non-cash unit-based compensation expense and $6.7 million of acquisition-related costs. The $2.1 million increase in general administrative expenses consisted of increased salaries and employee count between periods offset by $5.8 million of one-time compensation expense related to the Tanos management buyout during 2013.
Net gains on commodity derivative instruments of $492.3 million were recognized during 2014, consisting of $13.6 million of cash settlement receipts in addition to a $478.7 million increase in the fair value of open hedge positions. Net gains on commodity derivative instruments of $26.3 million were recognized during 2013, consisting of $19.9 million of cash settlement receipts, in addition to a $6.4 million increase in the fair value of open hedge positions.
Net interest expense is comprised of interest on credit facilities, interest on MEMP's outstanding senior notes, amortization of debt issue costs, accretion of net discount associated with the senior notes and gains and losses on interest rate swaps. Net interest expense totaled $83.6 million during 2014, including amortization of deferred financing fees of approximately $4.2 million and accretion of net discount associated with the senior notes of $1.9

million. Net interest expense totaled $41.9 million during 2013, including gains on interest rate swaps of $1.5 million and amortization of deferred financing fees of approximately $5.8 million. The increase in net interest expense is primarily the result of higher level of indebtedness during 2014 compared to 2013, including MEMP’s 2022 Senior Notes.

Average outstanding borrowings under MEMP's revolving credit facility were $413.6 million during 2014 compared to $184.7 million during 2013. Average outstanding borrowings under the previous owners' revolving credit facilities were $21.3 million during 2013. For the year ended December 31, 2014, MEMP had an average of $950.7 million aggregate principal amount of MEMP's senior notes issued and outstanding. For the year ended December 31, 2013, MEMP had an average of $342.2 million aggregate principal amount of MEMP's senior notes issued and outstanding.

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

MEMP recorded net income of $20.3 million in 2013 compared to income of $46.5 million in 2012.

Oil and natural gas sales were $341.2 million in 2013, an increase of $85.6 million from 2012. Production increased 13.0 Bcfe (approximately 30%) while the average realized sales price increased $0.16 per Mcfe. The favorable volume variance contributed to a $76.6 million increase in revenues, whereas the favorable pricing variance contributed to a $9.0 million decrease in revenues.

Lease operating expenses were $88.9 million in 2013, an increase of $8.8 million from 2012. Production and ad valorem taxes were $17.8 million in 2013, an increase of $1.8 million from 2012. Both lease operating expenses and production and ad valorem taxes increased primarily due to increased production volumes associated with properties acquired during both 2012 and 2013 and increased drilling activities.

The increase in DD&A expense was primarily due to increased production volumes related to acquisitions in 2012 and 2013 and increased drilling activities. Increased production volumes caused DD&A expense to increase by $22.8 million, while a 1% change in the DD&A rate between periods caused DD&A expense to decrease by $1.5 million. An increase in proved reserve volumes more than offset the impact of increases to the depletable cost base.

During 2013, MEMP recorded $54.4 million of impairments consisting of $50.3 million related to certain properties in East Texas and $4.1 million related to certain properties in South Texas. For the East Texas properties, the estimated future cash flows expected from these properties were compared to their carrying values and determined to be unrecoverable as a result of downward revisions of estimated proved reserves based upon updated well performance data. In South Texas, the estimated future cash flows expected from these properties were compared to their carrying values and determined to be unrecoverable as a result of a downward revision of estimated proved reserves based on pricing terms specific to these properties. During 2012, MEMP recorded impairments of $10.5 million primarily related to properties in the Permian Basin. The 2012 impairments were a result of downward revisions of estimated proved reserves due to unfavorable drilling results in the area.

In 2013, there was a $50.3 million impairment elimination as certain fields in East Texas noted above were not impaired on a consolidated basis.

General and administrative expenses were $43.5 million in 2013, an increase of $13.2 million. The increase in general and administrative expenses was primarily due to growth in employees as a result of acquisitions and drilling activities. General and administrative expenses for 2013 included $3.6 million of non-cash unit-based compensation expense and $6.7 million of acquisition-related costs. General and administrative expenses for 2012 were $30.3 million and included $1.4 million of non-cash unit-based compensation expense and $4.1 million of acquisition-related costs.

Net gains on commodity derivative instruments of $26.3 million were recognized during 2013, of which $19.9 million consisted of cash settlements. Net gains on commodity derivative instruments of $21.4 million were recognized during 2012, of which $44.1 million consisted of cash settlements. The decrease in cash settlements was primarily due to higher natural gas prices.

During 2013, a gain of approximately $2.8 million was recorded due to the sale of certain non-operated properties in East Texas. During 2012, a gain of approximately $9.8 million was recognized related to the sale of properties in Garza and Ector Counties in Texas.

Net interest expense during 2013 was $41.9 million, including amortization of deferred financing fees of approximately $5.8 million and gains on interest rate swaps of $1.5 million. Net interest expense during 2012 was $20.4 million, including amortization of deferred financing fees of approximately $0.6 million and losses on interest rate swaps of $4.0 million. The increase in net interest expense is primarily the result of higher level of indebtedness during 2013 compared to 2012.

Consolidated

For consolidated results of operations, see MRD Segment and MEMP Segment above.

Liquidity and Capital Resources

Although results are consolidated for financial reporting, the MRD and MEMP Segments operate with independent capital structures. The MEMP Segment's debt is nonrecourse to the Company. With the exception of cash distributions paid to the MRD Segment by the MEMP Segment related to MEMP partnership interests held by the Company the cash needs of each segment have been met independently with a combination of operating cash flows, asset sales, credit facility borrowings and the issuance of debt and equity. We expect that the cash needs of each of the MRD Segment and the MEMP Segment will continue to be met independently of each other with a combination of these funding sources.

MRD Segment

Historically, the primary sources of liquidity have been through borrowings under credit facilities, capital contributions from NGP and certain members of management, borrowings under a second lien term loan facility, issuance of senior notes, asset sales, including dropdowns to MEMP, and net cash provided by operating activities. The primary use of cash has been for the exploration, development and acquisition of natural gas and oil properties. As we pursue reserve and production growth, we continually monitor what capital resources, including equity and debt financings, are available to meet future financial obligations, planned capital expenditure activities and liquidity requirements. Any future success in growing proved reserves and production will be highly dependent on the capital resources available.

Currently, the primary sources of liquidity and capital resources are cash flows generated by operating activities and borrowings under our revolving credit facility. We also have the ability to issue additional equity and debt as needed through both private and public offerings. We may from time to time refinance our existing indebtedness including by issuing longer-term fixed rate debt to refinance shorter-term floating rate debt.

Based on our current oil and natural gas price expectations, we believe our cash flows provided by operating activities and availability under our revolving credit facility will provide us with the financial flexibility and wherewithal to meet our cash requirements, including normal operating needs, and pursue our currently planned 2015 development drilling activities. However, future cash flows are subject to a number of variables, including the level of our oil and natural gas production and the prices we receive for our oil and natural gas production, and significant additional capital expenditures will be required to more fully develop our properties and acquire additional properties. We cannot assure you that operations and other needed capital will be available on acceptable terms, or at all.

As of December 31, 2014, our liquidity of $547.0 million consisted of $5.0 million of cash and cash equivalents and $542.0 million of available borrowings under our revolving credit facility. As of December 31, 2014, we had a working capital balance of $65.2 million. As of December 31, 2014, the borrowing base under our revolving credit facility was $725.0 million and we had $183.0 million of outstanding borrowings. The borrowing base under our revolving credit facility is subject to redetermination on at least a semi-annual basis based on an engineering report with respect to our estimated oil and natural gas reserves, which will take into account the prevailing oil and natural gas prices at such time, as adjusted for the impact of our commodity derivative contracts. Unanimous approval by the lenders is required for any increase to the borrowing base. The next borrowing base redetermination is scheduled for April 2015. A continuing decline in oil and natural gas prices or a prolonged period of lower oil and natural gas prices could result in a reduction of our borrowing base under our revolving credit facility and could trigger mandatory principal repayments.

Capital Budget

The amount and timing of our capital expenditures is largely discretionary and within our control, with the exception of certain projects managed by other operators. If oil and natural gas prices decline below levels we deem acceptable, we may defer a portion of our planned capital expenditures until later periods. Accordingly, we routinely monitor and adjust our capital expenditures in response to changes in oil and natural gas prices, drilling and acquisition costs, industry conditions and internally generated cash flow. Matters outside of our control that could affect the timing of our capital expenditures include obtaining required permits and approvals in a timely manner and the availability of rigs and labor crews.

Capital expenditures totaled $517.5 million for the year ended December 31, 2014 and included $97.8 million related to acquisitions. In 2014, MRD spent approximately 90% of its capital expenditures in the Terryville Complex and Other North Louisiana, 5% in East Texas and 5% in the Rockies. Our current estimated drilling and completion capital expenditure budget for 2015 is $475.0 million to $525.0 million, with substantially all capital expenditures dedicated to the Terryville Complex.

Cash Flows from Operating, Investing and Financing Activities

The following tables summarize segment cash flows from operating, investing and financing activities for the periods indicated. For information regarding the individual components of our cash flow amounts, see the Statements of Consolidated and Combined Cash Flows under "Item 8. Financial and Supplementary Data," contained herein.

MRD Segment

	For Year Ended December 31,		
	2014	2013	2012
Net cash provided by operating activities	$251,370	$83,910	$84,172
Net cash provided by (used in) investing activities:			
Acquisition of oil and natural gas properties	$(93,909)	$(67,098)	$(83,055)
Additions to oil and gas properties	(410,151)	(198,340)	(165,203)
Additions to other property and equipment	(16,978)	(2,432)	(1,268)
Equity investments in MEMP Segment	(570)	(521)	(206)
Distributions received from MEMP Segment related to partnership interests	6,144	26,006	19,263
Decrease (increase) in restricted cash	49,946	(49,347)	—
Proceeds from the sale of oil and gas properties to third parties	6,700	151,187	—
Proceeds from the sale of MEMP common units	—	135,012	—
Other	(516)	—	(2)
Net cash provided by (used in) investing activities	$(459,334)	$(5,533)	$(230,471)
Net cash provided by (used in) financing activities			
Advances on revolving credit facilities	$1,300,800	$174,400	$228,450
Payments on revolving credit facilities	(1,320,900)	(280,500)	(129,750)
Proceeds from issuance of senior notes	600,000	343,000	—
Redemption of senior notes	(351,808)	—	—
Borrowings under second lien credit facility	—	325,000	—
Redemption of second lien credit facility	(328,282)	—	—
Deferred financing costs	(18,840)	(20,267)	(1,276)
Purchase of additional interests in consolidated subsidiaries	(3,292)	(13,865)	—
Net proceeds from initial public offering	380,127	—	—
Repurchased shares under repurchase program	(161)	—	—
Contribution from NGP affiliates related to sale of properties	1,165	—	7,033
Contributions from MEMP Segment	48,880	180,260	29,280
Distributions to Funds	—	(732,362)	—
Distributions to MRD Holdco	(59,803)	—	—
Distributions to noncontrolling interest	(325)	(7,446)	—
Distributions to MEMP Segment	—	—	(1,900)
Distribution to NGP affiliates related to purchase of assets	(66,693)	—	—
Distribution to NGP affiliates related to sale of assets, net of cash received	(32,770)	—	—
Distributions made by previous owners	—	(2,590)	(2,317)
Other cash transfers from MEMP Segment	—	—	3,751
Other	269	(4,593)	—
Net cash provided by (used in) financing activities	$148,367	$(38,963)	$133,271

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

Operating Activities. Net cash flows provided by operating activities were $251.4 million during 2014 compared to $83.9 million during 2013. Production increased 36.0 Bcfe (approximately 77%) and average realized sales price decreased $0.04 per Mcfe as previously discussed above under “Results of Operations—MRD Segment.” Cash paid for interest during 2014 was $67.0 million compared to $61.1 million during 2013. During 2014, compensation expense of approximately $26.7 million was paid in cash related to WildHorse Resources’ incentive units compared to $43.3 million in 2013 related to incentive units.

Investing Activities. Total cash used in investing activities was $459.3 million during 2014 compared to $5.5 million during 2013. Cash used for the acquisition of oil and gas properties was $93.9 million during 2014 compared to $67.1 million used in 2013. The 2014 and 2013 acquisitions were for certain properties located in Louisiana. Cash used for additions to oil and gas properties was $410.2 million during 2014 compared to $198.3 million during 2013, which consisted primarily of drilling and completion activities in the Cotton Valley in North Louisiana and East Texas area. Additions to other property and equipment were $17.0 million which consisted primarily of computer hardware, software, and other leased office space build out during 2014. Distributions of $6.1 million were received from MEMP primarily from the subordinated units owned by MRD LLC through June 18, 2014 compared to $26.0 million during 2013 received from MEMP primarily from the common and subordinated units then owned by MRD LLC. In May 2014, Black Diamond sold certain producing and non-producing properties in the Mississippian oil play of Northern Oklahoma to a third party for cash consideration of approximately $6.7 million. On July 31, 2013, BlueStone entered into an agreement with a third party to sell its remaining interest in certain properties in the Mossy Grove Prospect in Walker and Madison Counties located in East Texas. Total cash consideration received by BlueStone was approximately $117.9 million. On June 4, 2013, Black Diamond sold certain of its Wyoming oil and gas properties to a third party for cash consideration of approximately $32.9 million. In 2014, there was a decrease in restricted cash of $49.9 million, which was primarily due to $50.0 million being released from the debt service reserve account associated with the PIK notes. In November 2013, MRD LLC sold 7,061,294 MEMP common units in a secondary public offering, which generated net proceeds of $135.0 million.

Financing Activities. On June 18, 2014, we completed our initial public offering pursuant to which we sold 21,500,000 shares of our common stock to the public at an offering price of $19.00 per share. Net proceeds from our initial public offering were $380.1 million. We used approximately $360.0 million of our initial public offering proceeds to redeem the PIK notes on June 27, 2014, of which $351.8 million was classified as a financing activity and the remaining $8.2 million was classified as an operating activity representing interest expense.

Net repayments under revolving credit facilities were $20.1 million during 2014 compared to net repayments of $106.1 million during 2013. Amounts borrowed under our revolving credit facility were primarily incurred to repay the amounts outstanding under WildHorse Resources' credit facilities in connection with the closing of our initial public offering. WildHorse Resources primarily utilized its revolving credit facility during 2014 to repurchase net profits interests from an affiliate of NGP. On June 13, 2013, WildHorse Resources borrowed $325.0 million under its second lien term loan agreement and used such borrowings to reduce outstanding indebtedness under its revolving credit facility and to pay a one-time special $225.0 million distribution to MRD LLC, which MRD LLC subsequently distributed to the Funds. In connection with the closing of our initial public offering, WildHorse Resources' second lien term loan was repaid in full, including a premium of approximately $3.3 million.

Net proceeds of $586.8 million from the issuance of the MRD Senior Notes during the year ending December 31, 2014 were used to repay portions of our borrowings outstanding under our revolving credit facility.

Distributions to NGP affiliates related to the purchase of assets were primarily related to WildHorse Resources' February 2014 acquisition of net profits interests in the Terryville Complex from an affiliate of NGP for $63.4 million. MRD Royalty also acquired certain interests in oil and gas properties in Gonzales and Karnes Counties located in South Texas from an affiliate of NGP for $3.3 million in March 2014. Distributions to NGP affiliates related to the sale of assets were $32.8 million. WildHorse Resources sold its subsidiary, WHR Management Company, to an affiliate of the Funds for approximately $0.2 million and $33.0 million of cash was a component of the net book value transferred. For additional information regarding this transaction, see Note 13 of the Notes to Consolidated and Combined Financial Statements included under "Item 8. Financial and Supplementary Data," contained herein.

MEMP paid $33.9 million to WildHorse Resources in connection with MEMP's April 2014 acquisition of certain oil and natural gas properties in East Texas. MEMP paid $15.0 million to MRD in connection with MEMP's acquisition of certain oil and gas properties in the Rockies in October 2014. MEMP paid $55.4 million to WildHorse Resources in connection with MEMP's March 2013 acquisition of all the outstanding equity interests in WHT. MEMP paid $96.4 million to MRD LLC related to acquisitions of certain oil and natural gas properties in October 2013. Tanos also distributed approximately $20.9 million to MRD LLC during 2013.

In connection with our initial public offering, certain former management members of WildHorse Resources contributed their 0.1% membership interest and incentive units in WildHorse Resources in exchange for 42,334,323 shares of our common stock and cash consideration of $30.0 million. The portion of the total consideration related to acquiring the 0.1% membership interest was $3.3 million. In November 2013, MRD LLC purchased noncontrolling interests in Black Diamond, Classic GP and Classic for $13.9 million in cash.

Distributions to MRD Holdco during 2014 were $59.8 million. Approximately $6.7 million of cash received by MRD LLC in connection with the sale of assets in May 2014 was distributed to MRD Holdco in connection with our initial public offering. We also reimbursed MRD LLC for the approximately $17.2 million interest payment that it made on the PIK notes on June 15, 2014, which was distributed to MRD Holdco. Remaining cash of $32.8 million released from the debt service reserve account in connection with the redemption and discharge of the PIK notes was also distributed to MRD Holdco.

Distributions to the Funds during 2013 were $732.4 million. From time to time, MRD LLC made distributions of cash to the Funds. The timing and amount of these cash distributions was within the discretion of the board of managers of MRD LLC and was based, in part, upon available cash, the performance of its business, and other relevant factors. In 2013, substantially all of the cash distributed to the Funds was sourced from long term borrowings or sales of assets or equity in MEMP. The sources to fund these distributions primarily included $225.0 million from the WildHorse second lien term loan, $210.0 million from the December 2013 PIK notes, $63.8 million from the sale of properties to third parties, $125.0 million from the sale of properties to MEMP and $105.0 million from the sale of 7,061,294 MEMP common units that MRD LLC owned. Distributions to noncontrolling interests and previous owners totaled $10.0 million in 2013. Deferred financing costs of approximately $18.8 million were incurred during 2014 compared to approximately $20.3 million during 2013.

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

Operating Activities. Net cash flows provided by operating activities were $83.9 million in 2013 compared to $84.2 million in 2012. Although production volumes increased 15.1 Bcfe (approximately 48%), net cash flows from operating activities were impacted by $43.3 million of compensation expense recognized in 2013 related to incentive unit payments, which was an increase of $33.8 million from 2012.

Investing Activities. Cash used in investing activities was $5.5 million during 2013 compared to $230.5 million in 2012. Cash used for the acquisition of oil and gas properties was $67.1 million in 2013 compared to $83.1 million in 2012. The 2013 acquisition was for certain properties located in Louisiana that were purchased in March 2013. The 2012 acquisitions consisted primarily of properties located in East Texas and North Louisiana.

Cash used for additions to oil and gas properties was $198.3 million in 2013 compared to $165.2 million in 2012. The additions in both 2013 and 2012 consisted primarily of drilling and completion activities focused on the Cotton Valley formation in North Louisiana and East Texas.

Distributions of $26.0 million were received in 2013 from MEMP related to the common and subordinated units owned by MRD LLC as compared to $19.3 million received in 2012. In November 2013, MRD LLC sold 7,061,294 MEMP common units in a public offering, which generated net proceeds of $135.0 million.

Proceeds from the sale of oil and gas properties totaled $151.2 million in 2013. In May 2013, Black Diamond sold certain of its Wyoming properties for approximately $33.0 million. In July 2013, BlueStone sold its interest in certain properties located in Walker and Madison Counties in East Texas for approximately $117.9 million. There were no sales of oil and gas properties in 2012.

Additions to restricted cash totaled $49.3 million and were primarily related to the $50.0 million debt service reserve established in connection with the issuance of the PIK notes in December 2013.

Financing Activities. Cash used in financing activities was $39.0 million in 2013 compared to cash provided by financing activities of $133.3 million in 2012. Net payments under revolving credit facilities were $106.1 million in 2013 compared to net borrowings of $98.7 million in 2012. In June 2013, WildHorse Resources received gross proceeds of $325.0 million under its second lien term loan and in December 2013, MRD LLC received gross proceeds of $343.0 million related to the issuance of the PIK notes. Deferred financing costs were $20.3 million in 2013 compared to $1.3 million in 2012. The increase in deferred financing costs was primarily due to the WildHorse second lien term loan and the PIK notes.

In November 2013, MRD LLC purchased the noncontrolling interests in Black Diamond, Classic GP and Classic for $13.9 million of aggregate consideration.

Cash received from the MEMP Segment in 2013 related to the sale of assets from the MRD Segment to the MEMP Segment was $180.3 million compared to $29.3 million.

Distributions to the Funds during 2013 were $732.4 million as discussed above. Distributions to noncontrolling interests and previous owners totaled $10.0 million in 2013 compared to $2.3 million in 2012.

MEMP Segment

	For Year Ended December 31,		
	2014	2013	2012
Net cash provided by operating activities	$224,898	$193,697	$156,844
Net cash provided by (used in) investing activities:			
Acquisition of oil and natural gas properties	$(1,083,761)	$(38,664)	$(277,623)
Additions to oil and gas properties	(264,245)	(161,675)	(107,789)
Additions to other property and equipment	(89)	(238)	(1,748)
Additions to restricted investments	(3,976)	(5,361)	(4,599)
Proceeds from the sale of oil and gas properties to third parties	—	4,525	34,521
Other	—	—	29
Net cash provided by (used in) investing activities	$(1,352,071)	$(201,413)	$(357,209)
Net cash provided by (used in) financing activities			
Advances on revolving credit facilities	$1,446,000	$958,355	$391,000
Payments on revolving credit facilities	(1,137,000)	(1,485,537)	(121,819)
Proceeds from the issuances of senior notes	492,425	688,563	—
Deferred financing costs	(11,494)	(20,908)	(2,225)
Net proceeds from public equity offering	540,778	490,138	194,304
Repurchases under MEMP unit repurchase program	(11,531)	—	—
Restricted units returned to plan	(1,012)	—	—
Contributions from previous owners	—	7,233	44,072
Contribution from NGP affiliate	—	2,013	38,125
Contribution from general partner	570	521	206
Contribution from MRD Segment	—	—	1,900
Distributions to partners	(154,852)	(96,643)	(34,436)
Distributions to MRD Segment	(48,880)	(180,260)	(29,280)
Distributions to NGP affiliates	—	(355,495)	(242,174)
Distributions made by previous owners	—	(2,552)	(26,455)
Other cash transfers to MRD Segment	—	—	(3,751)
Other	—	(9,013)	(646)
Net cash provided by (used in) financing activities	$1,115,004	$(3,585)	$208,821

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

Operating Activities. Net income increased by $97.8 million as further discussed above under “Results of Operations—MEMP Segment,” and net cash provided by operating activities increased by $31.2 million. Cash paid for interest during 2014 was $63.7 million compared to $40.4 million during 2013. Net cash provided by operating activities included $12.8 million period-to-period increase in cash flow attributable to the timing of cash receipts and disbursements related to operating activities during 2014 compared to 2013.

Investing Activities. Net cash used in investing activities during 2014 was $1.36 billion, of which $1.08 billion was used to acquire oil and natural gas properties from third parties and $264.2 million was used for additions to oil and gas properties. Cash used in investing activities during 2013 was $201.4 million, of which $38.7 million was used to acquire oil and natural gas properties from a third parties and $161.7 million was used for additions to oil and gas properties. During the year ended December 31, 2013, Tanos had sales proceeds of $4.5 million related to the sale of oil and natural gas properties. Various restricted investment accounts fund certain long-term contractual and regulatory asset retirement obligations and collateralize certain regulatory bonds associated with MEMP’s offshore Southern California oil and gas properties. During 2014 and 2013, additions to restricted investments were $4.0 million and $5.4 million, respectively.

Financing Activities. During 2014, MEMP issued a total of 24,840,000 common units generating gross proceeds of approximately $553.3 million offset by approximately $12.5 million of costs incurred in conjunction with the issuance of common units. The net proceeds from these issuances were primarily used to repay borrowings under MEMP's revolving credit facility. In March 2013, MEMP issued 9,775,000 common units generating gross proceeds of approximately $179.4 million offset by approximately $7.6 million of costs incurred in conjunction with the issuance of common units. The net proceeds from this equity offering, including MEMP GP's proportionate capital contribution, partially funded the acquisition of all of the outstanding equity interests in WHT. In October 2013, MEMP issued 16,675,000 common units generating gross proceeds of $331.8 million offset by approximately $13.5 million of costs incurred in conjunction with the issuance of common units. The net proceeds from this equity offering, including MEMP GP's proportionate contribution, were used to repay a portion of outstanding borrowings under MEMP's revolving credit facility.

Distributions to partners during 2014 were $154.9 million compared to $96.6 million during 2013, of which the MRD Segment received $6.1 million during 2014 compared to $26.0 million during 2013. The increase in total distributions is due to both an increase in MEMP's outstanding units between periods and an increase in the declared cash distribution rate per unit. The decrease in distributions to the MRD Segment is due to MRD LLC selling 7,061,294 common units in November 2013 and the distribution of 5,360,912 subordinated units to MRD Holdco in June 2014 in connection with our initial public offering.

MEMP paid $33.9 million to WildHorse Resources in connection with MEMP's April 2014 acquisition of certain oil and natural gas properties in East Texas. MEMP paid $15.0 million to MRD in connection with MEMP's October 2014 acquisition of certain oil and gas properties in the Rockies. MEMP paid $55.4 million to WildHorse Resources in connection with its March 2013 acquisition of all of the outstanding equity interests in WHT and repaid $89.3 million of indebtedness under WHT's credit facility. MEMP paid MRD LLC $96.4 million related to the October 2013 acquisition of certain oil and natural gas properties. Distributions to NGP and affiliates were $355.5 million and Tanos distributed approximately $28.6 million to MRD LLC during 2013.

MEMP's previous owners received contributions of $7.2 million during 2013, of which Tanos received $5.9 million from MRD LLC. Distributions made by MEMP's previous owners totaled $2.6 million in 2013.

MEMP had net payments of $527.2 million under its revolving credit facilities during 2013. Borrowings under revolving credit facilities were used primarily to fund distributions associated with acquisitions of oil and gas properties from affiliates of NGP. MEMP had borrowings of $1.45 billion under its revolving credit facility during 2014 that were used primarily to fund its acquisitions and drilling program. Deferred financing costs of approximately $11.5 million were incurred during 2014 compared to approximately $20.9 million during 2013.

MEMP had unit repurchases of $11.5 million and $1.0 million in units returned to the MEMP GP Long-Term Incentive Plan during 2014.

Net proceeds of $484.0 million from the issuance of the senior notes during 2014 were used to repay borrowings outstanding under MEMP's revolving credit facility. Proceeds of $688.6 million from the issuances of senior notes were generated during 2013 and used to repay borrowings outstanding under MEMP's revolving credit facility.

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

Operating Activities. Net cash flows provided by operating activities increased during 2013 primarily due to an increase in production volumes as a result of acquisitions and increased drilling activities. Cash flows provided by operating activities at the MEMP Segment are used primarily to fund distributions to its partners and additions to oil and gas properties. The previous owners primarily used cash flows provided by operating activities to fund its exploration and development expenditures.

Investing Activities. Cash used in investing activities during 2013 was $201.4 million, of which $38.7 million was used to acquire oil and gas properties located in Wyoming and East Texas and $161.7 million was used for additions to oil and gas properties. Cash used in investing activities during 2012 was $357.2 million, of which $277.6 million was used to acquire oil and gas properties and $107.8 million was used for additions to oil and gas properties. The 2012 acquisitions included $126.9 million of acquisitions in East Texas and $150.7 million of acquisitions in the Permian Basin.

Various restricted investment accounts fund certain long-term contractual and regulatory asset retirement obligations and collateralize certain regulatory bonds associated with the offshore Southern California oil properties. During 2013 and 2012, additions to restricted investments were $5.4 million and $4.6 million, respectively.

Proceeds from the sale of oil and gas properties were $4.5 million in 2013 compared to $34.5 million in 2012. The 2013 sales primarily consisted of certain non-operated properties in East Texas while the 2012 sales primarily consisted of certain properties in Garza and Ector counties located in West Texas.

Financing Activities. Cash used in financing activities was $3.6 million in 2013 compared to cash provided by financing activities of $208.8 million in 2012.

MEMP generated total net proceeds of $490.1 million from two separate equity offerings in 2013 as discussed above compared to $194.3 million in December 2012. The net proceeds from the December 2012 offering were used to fund a portion of MEMP’s Beta acquisition and to repay indebtedness under MEMP’s revolving credit facility.

As discussed above, the net proceeds from the issuance of senior notes during 2013 were used to repay indebtedness under MEMP’s revolving credit facility. No senior notes were issued during 2012.

Distributions to partners were $96.6 million during 2013 compared to $34.4 million during 2012 due to increases in both declared distribution rates per unit and increases in the number of outstanding units. Distributions to the MRD Segment totaled $180.3 million in 2013 compared to $29.3 million in 2012. These distributions were primarily associated with the acquisition of assets by MEMP from the MRD Segment. Distributions to NGP affiliates were $355.5 million in 2013 compared to $242.2 million in 2012. The 2013 distribution was associated with the acquisition of assets by MEMP from certain affiliates of NGP in October 2013. The 2012 distribution was associated with the acquisition of assets located offshore Southern California from an affiliate of NGP.

Contributions of $9.8 million were received during 2013 compared to $84.3 million during 2012. Distributions made by the previous owners totaled $2.6 million in 2013 compared to $26.5 million in 2012.

MEMP had net payments of $527.2 million during 2013 related to revolving credit facilities. Borrowings under revolving credit facilities were used primarily to fund distributions associated with acquisitions of oil and gas properties from affiliates of NGP. Net proceeds from the issuance of the senior notes and common unit public equity offerings were used to repay borrowings under MEMP's revolving credit facility. During 2012, MEMP had net borrowings of $269.2 million related to revolving credit facilities. These borrowings were primarily used to fund distributions associated with acquisitions of oil and gas properties from affiliates of NGP. Deferred financing costs of $20.9 million were incurred during 2013 associated with both the senior notes and MEMP's revolving credit facility compared to $2.2 million incurred in 2012 related to revolving credit facilities.

Debt Agreements—MRD Segment

Revolving Credit Facility

In June 2014, we, as borrower, and certain of our subsidiaries, as guarantors, entered into a revolving credit facility, which is a five-year, $2.0 billion revolving credit facility with a borrowing base of $725 million as of December 31, 2014. The revolving credit facility is reserve-based, and thus our borrowing base is primarily based on the estimated value of our oil and natural gas properties and our commodity derivative contracts as determined semi-annually by our lenders in their sole discretion. In the future, we may be unable to access sufficient capital under the revolving credit facility as a result of (i) a decrease in our borrowing base due to a subsequent borrowing base redetermination or (ii) an unwillingness or inability on the part of our lenders to meet their funding obligations.

A further decline in commodity prices could result in a redetermination that lowers our borrowing base in the future and, in such case, we could be required to repay any indebtedness in excess of the borrowing base, or we could be required to pledge other oil and natural gas properties as additional collateral. If a redetermination of our borrowing base results in our borrowing base being less than our aggregate elected commitments, our aggregate elected commitments will be automatically reduced to the amount of such reduced borrowing base. We do not anticipate having any substantial unpledged properties, and we may not have the financial resources in the future to make any mandatory principal prepayments required under the revolving credit facility.

The revolving credit commitments could be terminated and any outstanding indebtedness together with accrued interest, fees and other obligations under the revolving credit facility, could be declared immediately due and payable if there is a default under our revolving credit facility.

We believe we were in compliance with all the financial (interest coverage ratio and current ratio) and other covenants associated with our revolving credit facility as of December 31, 2014.

See Note 8 under "Item 8. Financial Statements and Supplementary Data" for additional information regarding our revolving credit facility.

MRD Senior Notes

In July 2014, MRD completed a private placement of $600.0 million aggregate principal amount of 5.875% senior unsecured notes due 2022 (the "MRD Senior Notes"). The MRD Senior Notes will mature on July 1, 2022 with interest accruing at a rate of 5.875% per annum and payable semi-annually in arrears on January 1 and July 1 of each year. The MRD Senior Notes are governed by an indenture dated as of July 10, 2014. The MRD Senior Notes are fully and unconditionally guaranteed, subject to customary release provisions, on a senior unsecured basis by certain of our existing subsidiaries. See Note 8 under "Item 8. Financial Statements and Supplementary Data" for additional information regarding the MRD Senior Notes.

Debt Agreements—MEMP Segment

MEMP Revolving Credit Facility

Memorial Production Operating LLC ("OLLC"), a wholly-owned subsidiary of MEMP, is party to a $2.0 billion revolving credit facility, with a current borrowing base of $1.44 billion that matures in March 2018 and is guaranteed by MEMP and all of its current and future subsidiaries (other than certain immaterial subsidiaries). See Note 8 under "Item 8. Financial Statements and Supplementary Data" for additional information regarding MEMP's revolving credit facility.

Senior Notes

In April 2013, May 2013 and October 2013, MEMP and Memorial Production Finance Corporation ("Finance Corp.") (collectively, "the Issuers") issued $300.0 million, $100.0 million and $300.0 million, respectively, of their 7.625% senior unsecured notes due 2021 (the "2021 Senior Notes"). The 2021 Senior Notes are fully and unconditionally guaranteed (subject to customary release provisions) on a joint and several basis by all of MEMP's subsidiaries (other than Finance Corp., which is co-issuer of the 2021 Senior Notes, and certain immaterial subsidiaries). The 2021 Senior Notes will mature on May 1, 2021 with interest accruing at a rate of 7.625% per annum and payable semi-annually in arrears on May 1 and November 1 of each year. The 2021 Senior Notes were issued under and are governed by an indenture dated as of April 17, 2013.

In July 2014, the Issuers completed a private placement of $500.0 million aggregate principal amount of their 6.875% senior unsecured notes due 2022 (the "2022 Senior Notes"). The 2022 Senior Notes were issued at 98.485% of par and are fully and unconditionally guaranteed (subject to customary release provisions) on a joint and several basis by all of MEMP's subsidiaries (other than Finance Corp., which is co-issuer of the 2022 Senior Notes, and certain immaterial subsidiaries). The 2022 Senior Notes will mature on August 1, 2022 with interest accruing at 6.875% per annum and payable semi-annually in arrears on February 1 and August 1 of each year. The 2022 Senior Notes were issued under and are governed by an indenture dated as of July 17, 2014.

See Note 8 under "Item 8. Financial Statements and Supplementary Data" for additional information regarding the 2021 Senior Notes and 2022 Senior Notes.

Contractual Obligations

In the table below, we set forth our consolidated contractual obligations as of December 31, 2014 disaggregated by business segment. The contractual obligations that will actually be paid in future periods may vary from those reflected in the table because the estimates and assumptions are subjective.

		Payment Due by Period (in thousands)			
Purchase commitment	Total	2015	2016-2017	2018-2019	Thereafter
Revolving credit facility (1)					
MRD Segment	$ 183,000	$—	$—	$ 183,000	$—
MEMP Segment	412,000	—	—	412,000	—
Estimated interest payments (2)					
MRD Segment	15,477	3,642	7,283	4,552	—
MEMP Segment	47,512	11,179	22,359	13,974	—
Senior Notes (3)					
MRD Segment	881,217	37,404	70,500	70,500	702,813
MEMP Segment	1,823,657	89,469	175,500	175,500	1,383,188
Asset retirement obligation (4)					
MRD Segment	12,159	—	1,684	2,186	8,289
MEMP Segment	110,372	—	5,189	3,706	101,477
Decommissioning trust agreement (5)					
MEMP Segment	10,350	4,140	6,210	—	—
Operating leases (6)					
MRD Segment	43,625	6,534	13,301	12,219	11,571
MEMP Segment	3,665	788	621	410	1,846
Compression services					
MRD Segment	1,860	1,860	—	—	—
MEMP Segment	6,526	6,526	—	—	—
Drilling services					
MRD Segment	48,543	48,543	—	—	—
Processing Plant Demand Fees (7)					
MRD Segment	375,560	37,941	91,125	57,818	188,676
CO_2 minimum purchase commitment (8)					
MEMP Segment	50,495	9,608	20,330	14,055	6,502
MRD subtotal	1,561,441	135,924	183,893	330,275	911,349
MEMP subtotal	2,464,577	121,710	230,209	619,645	1,493,013
Total	4,026,018	257,634	414,102	949,920	2,404,362

(1) Represents the scheduled future maturities of principal amounts outstanding for the periods indicated. See the Notes to the Consolidated and Combined Financial Statements under “Item 8. Financial Statements and Supplementary Data,” contained herein for information regarding our revolving credit facilities.

(2) Estimated interest payments are based on the principal amount outstanding under revolving credit facilities at December 31, 2014. In calculating these amounts, we applied the weighted-average interest rate during 2014 associated with such debt. See the Notes to the Consolidated and Combined Financial Statements under “Item 8. Financial Statements and Supplementary Data,” contained herein for the weighted-average variable interest rate charged during 2014 under these credit facilities. In addition, the estimate of payments for interest gives effect to interest rate swap agreements that were in place at December 31, 2014.

(3)

Represents the scheduled future interest payments and principal payments on the Senior Notes. See the Notes to the Consolidated and Combined Financial Statements under "Item 8. Financial Statements and Supplementary Data," contained herein, for information regarding debt agreements.

(4) Asset retirement obligations represent estimated discounted costs for future dismantlement and abandonment costs. These obligations are recorded as liabilities on our December 31, 2014 balance sheet. See the Notes to Consolidated and Combined Financial Statements included under "Item 8. Financial Statements and Supplementary Data" contained herein for additional information regarding our asset retirement obligations.

(5) Pursuant to a BOEM decommissioning trust agreement, MEMP is required to fund a trust account to comply with supplemental regulatory bonding requirements related to MEMP decommissioning obligations for its offshore Southern California production facilities. See the Notes to Consolidated and Combined Financial Statements included under "Item 8. Financial Statements and Supplementary Data" contained herein for additional information.

(6) Primarily represents leases for office space and MEMP's offshore Southern California right-of-way use. See the Notes to Consolidated and Combined Financial Statements included under "Item 8. Financial Statements and Supplementary Data" contained herein for additional information regarding operating leases.

(7) Represents minimum commitments to the gatherer. See the Notes to the Consolidated and Combined Financial Statements under "Item 8. Financial Statements and Supplementary Data," contained herein, for information regarding processing plant demand fees.

(8) Represents a firm agreement, which MEMP assumed in the Wyoming Acquisition, to purchase CO_2 volumes.

Critical Accounting Policies and Estimates

Natural Gas and Oil Properties

We use the successful efforts method of accounting to account for our natural gas and oil properties. Under this method, costs of acquiring properties, costs of drilling successful exploration wells, and development costs are capitalized. The costs of exploratory wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if a determination is made that proved reserves have been found. If no proved reserves have been found, the costs of each of the related exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. The costs of such exploratory wells are expensed if a determination of proved reserves has not been made within a twelve-month period after drilling is complete. Exploration costs such as geological, geophysical, and seismic costs are expensed as incurred.

As exploration and development work progresses and the reserves on these properties are proven, capitalized costs attributed to the properties are subject to depreciation and depletion. Depletion of capitalized costs is provided using the units-of-production method based on proved natural gas and oil reserves related to the associated field. Capitalized drilling and development costs of producing natural gas and oil properties are depleted over proved developed reserves and leasehold costs are depleted over total proved reserves.

On the sale or retirement of a complete or partial unit of a proved property or pipeline and related facilities, the cost and related accumulated depreciation, depletion, and amortization are eliminated from the property accounts, and any gain or loss is recognized.

Proved Natural Gas and Oil Reserves

The estimates of proved natural gas and oil reserves utilized in the preparation of the consolidated and combined financial statements are estimated in accordance with the rules established by the SEC and the FASB. These rules require that reserve estimates be prepared under existing economic and operating conditions using a trailing 12-month average price with no provision for price and cost escalations in future years except by contractual arrangements We intend to have our internally prepared reserve report as of December 31 of each year audited for a vast majority of our proved reserves and to prepare internal estimates of our proved reserves as of June 30 of each year.

Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. Oil and gas properties are depleted by field using the units-of-production method. It is possible that, because of changes in market conditions or the inherent imprecision of reserve estimates, the estimates of future cash inflows, future gross revenues, the amount of natural gas and oil reserves, the remaining estimated lives of natural gas and oil properties, or any combination of the above may be increased or reduced. Increases in recoverable economic volumes generally reduce per unit depletion rates while decreases in recoverable economic volumes generally increase per unit depletion rates.

A decline in proved reserves may result from lower market prices, which may make it uneconomical to drill for and produce higher cost fields. In addition, a decline in proved reserve estimates may impact the outcome of our assessment of oil and gas producing properties for impairment.

Impairments

Proved natural gas and oil properties are reviewed for impairment when events and circumstances indicate a possible decline in the recoverability of the carrying value of such properties, such as a downward revision of the reserve estimates, less than expected production, drilling results, higher operating and development costs, or lower commodity prices. The estimated undiscounted future cash flows expected in connection with the property are compared to the carrying value of the property to determine if the carrying amount is recoverable. If the carrying value of the property exceeds its estimated undiscounted future cash flows, the carrying amount of the property is reduced to its estimated fair value using Level 3 inputs. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties.

Incentive Units

Prior to our initial public offering, the governing documents of MRD LLC and certain of MRD LLC's subsidiaries, including WildHorse Resources and BlueStone, provided for the issuance of incentive units. Those incentive units were subject to performance conditions that affected their vesting. Compensation cost was recognized only if the performance condition was probable of being satisfied at each reporting date.

WildHorse Resources, BlueStone and MRD LLC each granted incentive units to certain of its members who were key employees at the time of grant. Holders of incentive units were entitled to distributions ranging from 10% to 31.5% when declared, but only after cumulative distribution thresholds (payouts) have been achieved. Payouts would have been generally triggered after the recovery of specified members' capital contributions plus a rate of return.

Vesting of incentive units is generally dependent upon an explicit service period, a fundamental change as defined in the respective governing document, and achievement of payout. All incentive units not vested are forfeited if an employee is no longer employed. All incentive units will be forfeited if a holder resigns whether the incentive units are vested or not. If the payouts have not yet occurred, then all incentive units, whether or not vested, will be forfeited automatically (unless extended).

In connection with the closing of our initial public offering, certain former management members of WildHorse Resources contributed to us their incentive units in WildHorse Resources, as well as the remaining 0.1% of the membership interests in WildHorse Resources in exchange for approximately 42.3 million shares of our common stock and cash consideration of $30.0 million. See Note 12 of the Notes to Consolidated and Combined Financial Statements under "Item 8. Financial and Supplementary Data," contained herein for additional information.

In connection with the restructuring transactions, the MRD LLC incentive units were exchanged for substantially identical units in MRD Holdco, and such incentive units entitle holders thereof to portions of future distributions by MRD Holdco. While any such distributions made by MRD Holdco will not involve any cash payment by us, we will be required to recognize non-cash compensation expense (income), which may be material, in the period in which the performance conditions are probable of being satisfied. The compensation expense (income) recognized by us related to the incentive units will be offset by a deemed capital contribution (distribution) from MRD Holdco. See Note 12 of the Notes to Consolidated and Combined Financial Statements under "Item 8. Financial and Supplementary Data," contained herein for additional information.

Derivative Instruments

Commodity derivative financial instruments (e.g., swaps, floors, collars, and put options) are used to reduce the impact of natural gas and oil price fluctuations. Interest rate swaps are used to manage exposure to interest rate volatility, primarily as a result of variable rate borrowings under credit facilities. Every derivative instrument is recorded in the balance sheet as either an asset or liability measured at its fair value. Changes in the derivative's fair value are recognized currently in earnings as we have not elected hedge accounting for any of our derivative positions.

Income Tax

Prior to our initial public offering, MRD LLC was organized as a pass-through entity for federal income tax purposes and was not subject to federal income taxes; however, certain of its consolidating subsidiaries were taxed as corporations and subject to federal income taxes. We are organized as a taxable C corporation and subject to federal and certain state income taxes. We are also subject to the Texas margin tax and certain aspects of the tax make it similar to an income tax as the tax is assessed on 1% of taxable margin apportioned to operations in Texas.

Deferred federal and state income taxes are provided on temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax basis. If it is more likely than not that some of the deferred tax assets will not be realized, the tax asset is reduced by a valuation allowance. In evaluating realizability of deferred tax assets, the Company refers to the reversal periods for available carryforward periods for net operating losses and credit carryforwards, temporary differences, the availability of tax planning strategies, the existence of appreciated assets and estimates of future taxable income and other factors. Estimates of future taxable income are based on assumptions of oil and gas reserves and selling prices that are consistent with the Company's internal business forecasts.

A tax benefit from an uncertain tax position is recognized when it is more likely than not that the position will be sustained upon examination, based on the technical merits of the position. The tax benefit recorded is equal to the largest amount that is greater than 50% likely to be realized through final settlement with a taxing authority.

In June 2014, we recorded a deferred tax liability in stockholders' equity in connection with our initial public offering and the related restructuring transactions. The tax bases of our assets and liabilities changed as a result our initial public offering and the related restructuring transactions, which represented a transaction among stockholders.

Off–Balance Sheet Arrangements

As of December 31, 2014, we had no off–balance sheet arrangements.

Recently Issued Accounting Pronouncements

For a discussion of recent accounting pronouncements that will affect us, see the Notes to the Consolidated and Combined Financial Statements under “Item 8. Financial and Supplementary Data,” contained herein. As discussed under Note 2 of the Notes to Consolidated and Combined Financial Statements included under “Item 8. Financial Statements and Supplementary Data,” the FASB issued an accounting standards update to improve consolidation guidance for certain types of legal entities in February 2015. The guidance, among other things, modifies the evaluation of whether limited partnerships and similar legal entities are variable interest entities (“VIEs”) or voting interest entities and eliminates the presumption that a general partner should consolidate a limited partnership. We will either: (i) continue to consolidate MEMP and become subject to the VIE primary beneficiary disclosure requirements or (ii) no longer consolidate MEMP under the revised VIE consolidation requirements and provide disclosures that apply to variable interest holders that do not consolidate a VIE. The deconsolidation of MEMP would have a material impact on our consolidated financial statements and related disclosures.

Section 107 of the Jumpstart Our Business Startups Act (“JOBS Act”) provides that an emerging growth company can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act for complying with new or revised accounting standards, but we have irrevocably opted out of the extended transition period and, as a result, we will adopt new or revised accounting standards on the relevant dates in which adoption of such standards is required for other public companies.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risk. The term “market risk” refers to the risk of loss arising from adverse changes in natural gas and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for purposes, other than for speculative trading.

Commodity Price Risk

Our cash flow from operations is subject to many variables, the most significant of which is the volatility of natural gas, NGL and oil prices. Natural gas, NGL and oil prices are determined primarily by prevailing market conditions, which are dependent on regional and worldwide economic activity, weather and other factors beyond our control. Our future cash flow from operations will depend on the prices of natural gas, NGL and oil and our ability to maintain and increase production through acquisitions and exploitation and development projects.

To reduce the impact of fluctuations in natural gas and oil prices on our revenues, or to protect the economics of property acquisitions, we periodically enter into derivative contracts with respect to a portion of our projected natural gas, NGL and oil production through various transactions to provide an economic hedge of the risk related to the future commodity prices received. These transactions may include price swaps, whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty, or basis swaps, whereby we will receive a fixed price differential and pay a variable price differential to the contract counterparty. Additionally, we may enter into collars, whereby we receive the excess, if any, of the fixed floor over the floating rate or pays the excess, if any, of the floating rate over the fixed ceiling price. We also may enter into put options that are designed to provide a fixed price floor with the opportunity for upside. These economic hedging activities are intended to support natural gas and oil prices at targeted levels and to manage our exposure to natural gas, NGL and oil price fluctuations. We do not enter derivative contracts for speculative trading purposes. Our revolving credit facility contains various covenants and restrictive provisions which, among other things, limit our ability to enter into commodity price hedges exceeding a certain percentage of production.

At December 31, 2014, the MRD Segment had the following open commodity positions:

	2015	2016	2017	2018
Natural Gas Derivative Contracts:				
Fixed price swap contracts:				
Average Monthly Volume (MMBtu)	3,700,000	2,570,000	1,770,000	2,900,000
Weighted-average fixed price	$4.15	$4.09	$4.24	$4.27
Collar contracts:				
Average Monthly Volume (MMBtu)	130,000	1,100,000	1,050,000	—
Weighted-average floor price	$4.00	$4.00	$4.00	$—
Weighted-average ceiling price	$4.64	$4.71	$5.06	$—
Natural gas put option contracts:				
Average Monthly Volume (MMBtu)	3,000,000	4,100,000	3,450,000	2,850,000
Weighted-average fixed price	$3.75	$3.75	$3.75	$3.75
Weighted-average deferred premium	$(0.33)	$(0.36)	$(0.35)	$(0.35)
TGT Z1 basis swaps:				
Average Monthly Volume (MMBtu)	1,730,000	220,000	200,000	—
Spread - Henry Hub	$(0.09)	$(0.08)	$(0.08)	$—
Crude Oil Derivative Contracts:				
Fixed price swap contracts:				
Average Monthly Volume (Bbls)	46,500	8,500	28,000	31,625
Weighted-average fixed price	$91.67	$84.80	$84.70	$84.50
Collar contracts:				
Average Monthly Volume (Bbls)	2,000	27,000	—	—
Weighted-average floor price	$85.00	$80.00	$—	$—
Weighted-average ceiling price	$101.35	$99.70	$—	$—
Put option contracts:				
Average Monthly Volume (Bbls)	26,000	—	—	—
Weighted-average fixed price	$85.00	$—	$—	$—
Weighted-average deferred premium	$(3.80)	$—	$—	$—
NGL Derivative Contracts:				
Fixed price swap contracts:				
Average Monthly Volume (Bbls)	151,000	185,658	—	—
Weighted-average fixed price	$41.61	$34.06	$—	$—

At December 31, 2014, the MEMP Segment had the following open commodity positions

	2015	2016	2017	2018	2019
Natural Gas Derivative Contracts:					
Fixed price swap contracts:					
Average Monthly Volume (MMBtu)	2,605,278	2,692,442	2,450,067	2,160,000	1,914,583
Weighted-average fixed price	$4.28	$4.40	$4.31	$4.51	$4.75
Collar contracts:					
Average Monthly Volume (MMBtu)	350,000	—	—	—	—
Weighted-average floor price	$4.62	$—	$—	$—	$—
Weighted-average ceiling price	$5.80	$—	$—	$—	$—
Call spreads (1):					
Average Monthly Volume (MMBtu)	80,000	—	—	—	—
Weighted-average sold strike price	$5.25	$—	$—	$—	$—
Weighted-average bought strike price	$6.75	$—	$—	$—	$—
Basis swaps:					
Average Monthly Volume (MMBtu)	2,940,000	2,508,333	415,000	115,000	—
Spread	$(0.12)	$(0.04)	$0.00	$0.15	$—
Crude Oil Derivative Contracts:					
Fixed price swap contracts:					
Average Monthly Volume (Bbls)	314,281	332,813	326,600	312,000	160,000
Weighted-average fixed price	$90.96	$85.83	$84.38	$83.74	$85.52
Collar contracts:					
Average Monthly Volume (Bbls)	5,000	—	—	—	—
Weighted-average floor price	$80.00	$—	$—	$—	$—
Weighted-average ceiling price	$94.00	$—	$—	$—	$—
Basis swaps:					
Average Monthly Volume (Bbls)	97,500	95,000	—	—	—
Spread	$(7.07)	$(9.56)	$—	$—	$—
NGL Derivative Contracts:					
Fixed price swap contracts:					
Average Monthly Volume (Bbls)	149,200	84,600	—	—	—
Weighted-average fixed price	$43.02	$41.49	$—	$—	$—

(1) These transactions were entered into for the purpose of eliminating the ceiling portion of certain collar arrangements, which effectively converted the applicable collars into swaps.

The MEMP Segment's basis swaps as of December 31, 2014 included in the table above are presented on a disaggregated basis below:

	2015	2016	2017	2018
Natural Gas Derivative Contracts:				
NGPL TexOk basis swaps:				
Average Monthly Volume (MMBtu)	2,280,000	2,103,333	300,000	—

Spread - Henry Hub	$(0.11)	$(0.06)	$(0.05)	$—
HSC basis swaps:				
Average Monthly Volume (MMBtu)	150,000	135,000	115,000	115,000
Spread - Henry Hub	$(0.08)	$0.07	$0.14	$0.15
CIG basis swaps:				
Average Monthly Volume (MMBtu)	210,000	—	—	—
Spread - Henry Hub	$(0.25)	$—	$—	$—
TETCO STX basis swaps:				
Average Monthly Volume (MMBtu)	300,000	270,000	—	—
Spread - Henry Hub	$(0.09)	$0.06	$—	$—
Crude Oil Derivative Contracts:				
Midway-Sunset basis swaps:				
Average Monthly Volume (Bbls)	57,500	55,000	—	—
Spread - Brent	$(9.73)	$(13.35)	$—	$—
Midland basis swaps:				
Average Monthly Volume (Bbls)	40,000	40,000	—	—
Spread - WTI	$(3.25)	$(4.34)	$—	$—

Interest Rate Risk

Periodically, we enter into interest rate swaps to mitigate exposure to market rate fluctuations by converting variable interest rates such as those in our credit agreement to fixed interest rates. As of December 31, 2014, we did not have open interest rate swap positions.

At December 31, 2014, the MEMP Segment had the following interest rate swap open positions:

Credit Facility	2015	2016	2017
MEMP:			
Average Monthly Notional (in thousands)	$314,167	$250,000	$250,000
Weighted-average fixed rate	1.349 %	1.029 %	1.620 %
Floating rate	1 Month LIBOR	1 Month LIBOR	1 Month LIBOR

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from commodity derivatives and the sale of our oil and gas production, which we market to energy companies.

By using derivative instruments that are not traded on an exchange to hedge exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates the credit risk. To minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market-makers. The creditworthiness of our counterparties is subject to periodic review. As of December 31, 2014, our derivative contracts are with major financial institutions, certain of which are also lenders under our revolving credit facilities. While collateral is generally not required to be posted by counterparties, credit risk associated with derivative instruments is minimized by limiting exposure to any single counterparty and entering into derivative instruments only with creditworthy counterparties that are generally large financial institutions. Additionally, master netting agreements are used to mitigate risk of loss due to default with counterparties on derivative instruments. We have also entered into the International Swaps and Derivatives Association Master Agreements ("ISDA Agreements") with each of our counterparties. The terms of the ISDA Agreements provide us and each of our counterparties with rights of set-off upon the occurrence of defined acts of default by either us or our counterparty to a derivative, whereby the party not in default may set-off all liabilities owed to the defaulting party against all net derivative asset receivables from the defaulting party. At December 31, 2014, MEMP had derivative net assets of $517.1 million. After taking into effect netting arrangements, MEMP had counterparty exposure of $309.8 million related to its derivative instruments. Had certain counterparties failed completely to perform according to the terms of their existing contracts, MEMP would have the right to offset $207.3 million against amounts outstanding under its revolving credit facility at December 31, 2014. At December 31, 2014, we had derivative assets of $255.0 million. After taking into effect netting arrangements, we had counterparty exposure of $155.8 million related to our derivative instruments. Had certain counterparties failed completely to perform according to the terms of their existing contracts, we would have the right to offset $99.2 million against amounts outstanding under our revolving credit facility at December 31, 2014. See Note 8 under "Item 8. Financial Statements and Supplementary Data" for additional information regarding our revolving credit facilities.

We are also subject to credit risk due to the concentration of our natural gas and oil receivables with several significant customers. We do not require our customers to post collateral, and the inability of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Our Consolidated and Combined Financial Statements, together with the report of our independent registered public accounting firm begin on page F-1 of this annual report.

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 Rules 13a-15(b) and 15d-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including the 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) and under the Exchange Act) as of the end of the period covered by this annual report. 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 the 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 the evaluation, the principal executive officer and principal financial have concluded that our disclosure controls and procedures were effective at the reasonable assurance level as of December 31, 2014.

Management's Report on Internal Control Over Financial Reporting

This annual report is not required to include a report of management's assessment regarding internal control over financial reporting or an attestation report of our independent registered public accounting firm due to a transition period established by rules of the SEC for newly public companies.

Changes in Internal Controls Over Financial Reporting

No changes in our internal control over financial reporting occurred during the quarter ended December 31, 2014 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

See “Directors,” “Corporate Governance Matters,” “Executive Officers,” “Security Ownership of Certain Beneficial Owners and Management,” and “Section 16(a) Beneficial Ownership Reporting Compliance” in the proxy statement relating to the Annual Meeting of Stockholders of Memorial Resource Development Corp. (the “Proxy Statement”) to be held May 15, 2015, each of which is incorporated herein by reference.

The Company’s Code of Business Conduct and Ethics and the Code of Ethics for Senior Financial Officers (collectively, the “Code of Ethics”) can be found on the Company’s website located at www.memorialrd.com/corporate-governance.cfm. Any stockholder may request a printed copy of the Code of Ethics by submitting a written request to the Company’s Corporate Secretary. If the Company amends the Code of Ethics or grants a waiver, including an implicit waiver, from the Code of Ethics, the Company will disclose the information on its website. The waiver information will remain on the website for at least 12 months after the initial disclosure of such waiver.

ITEM 11. EXECUTIVE COMPENSATION

See “Directors,” “Corporate Governance Matters,” “Director Compensation,” and “Executive Compensation” in the Proxy Statement, each of which is incorporated herein by reference.

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

See “Security Ownership of Certain Beneficial Owners and Management” in the Proxy Statement and “Securities Authorized for Issuance under Equity Compensation Plans” under Item 5 of this Form 10-K, which are incorporated herein by reference.

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

See “Certain Relationships and Related Party Transactions” in the Proxy Statement, which is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

See “Ratification of Appointment of Independent Registered Public Accounting Firm” in the Proxy Statement, which is incorporated herein by reference.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) Financial Statements

Our Consolidated and Combined Financial Statements are included under Part II, Item 8 of the annual report. For a listing of these statements and accompanying footnotes, see “Index to Financial Statements” Page F-1 of this annual report.

(a)(2) Financial Statement Schedules

All schedules have been omitted because they are either not applicable, not required or the information called for therein appears in the consolidated and combined financial statements or notes thereto.

(a)(3) Exhibits

Exhibit Number	Description
2.1##	—Purchase and Sale Agreement, dated as of September 18, 2012, by and among Memorial Production Operating LLC, Goodrich Petroleum Company, L.L.C. and Goodrich Petroleum Corporation (incorporated by reference to Exhibit 2.1 to Memorial Production Partners LP’s Current Report on Form 8-K (File No. 001-35364) filed on September 19, 2012).
2.2##	—Purchase and Sale Agreement, dated as of November 19, 2012, by and among Memorial Production Operating LLC and Rise Energy Partners, LP (incorporated by reference to Exhibit 2.1 to Memorial Production Partners LP’s Current Report on Form 8-K (File No. 001-35364) filed on November 20, 2012).
2.3##	—Purchase and Sale Agreement, dated as of March 18, 2013, among Memorial Resource Development LLC, Tanos Energy, LLC, WildHorse Resources, LLC and Memorial Production Operating LLC (incorporated by reference to Exhibit 2.1 to Memorial Production Partners LP’s Current Report on Form 8-K (File No. 001-35364) filed on March 19, 2013).
2.4##	—Purchase and Sale Agreement, dated as of July 15, 2013, between Boaz Energy Partners, LLC and Memorial Production Operating LLC (incorporated by reference to Exhibit 2.1 to Memorial Production Partners LP’s Current Report on Form 8-K (File No. 001-35364) filed on July 16, 2013).
2.5##	—Purchase and Sale Agreement, dated as of July 15, 2013, between Crown Energy Partners Holdings, LLC and Memorial Production Operating LLC (incorporated by reference to Exhibit 2.2 to Memorial Production Partners LP’s Current Report on Form 8-K (File No. 001-35364) filed on July 16, 2013).
2.6##	—Purchase and Sale Agreement, dated as of July 15, 2013, between Propel Energy, LLC and Memorial Production Operating LLC (incorporated by reference to Exhibit 2.3 to Memorial Production Partners LP’s Current Report on Form 8-K (File No. 001-35364) filed on July 16, 2013).

2.7##	—Purchase and Sale Agreement, dated as of July 15, 2013, between Stanolind Oil and Gas LP and Memorial Production Operating LLC (incorporated by reference to Exhibit 2.4 to Memorial Production Partners LP's Current Report on Form 8-K (File No. 001-35364) filed on July 16, 2013).
2.8##	—Purchase and Sale Agreement, dated as of July 15, 2013, between Memorial Resource Development LLC and Memorial Production Operating LLC (incorporated by reference to Exhibit 2.5 to Memorial Production Partners LP's Current Report on Form 8-K (File No. 001-35364) filed on July 16, 2013).
2.9##	—Purchase and Sale Agreement, dated as of May 2, 2014, among Merit Management Partners I, L.P., Merit Energy Partners III, L.P., Merit Pipeline Company, LLC and Merit Energy Company, LLC and Memorial Production Operating LLC (incorporated by reference to Exhibit 2.1 to Memorial Production Partners LP's Current Report on Form 8-K (File No. 001-35364) filed on May 5, 2014).
2.10##	—Purchase and Sale Agreement, dated as of March 25, 2014, between Alta Mesa Eagle, LLC and Memorial Production Operating LLC (incorporated by reference to Exhibit 2.1 to Memorial Production Partners LP's Current Report on Form 8-K (File No. 001-35364) filed on March 25, 2014).
3.1	—Amended and Restated Certificate of Incorporation of Memorial Resource Development Corp. dated June 10, 2014 (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K (File No. 001-36490) filed on June 16, 2014).

3.2 —Amended and Restated Bylaws of Memorial Resource Development Corp. dated June 10, 2014 (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K (File No. 001-36490) filed on June 16, 2014).

3.3 —Certificate of Limited Partnership of Memorial Production Partners LP (incorporated by reference to Exhibit 3.1 to Memorial Production Partners LP's Registration Statement on Form S-1 (File No. 333-175090) filed on June 23, 2011).

3.4 —First Amended and Restated Agreement of Limited Partnership of Memorial Production Partners LP (incorporated by reference to Exhibit 3.1 to Memorial Production Partners LP's Current Report on Form 8-K (File No. 001-35364) filed on December 15, 2011).

3.5 —Certificate of Formation of Memorial Production Partners GP LLC (incorporated by reference to Exhibit 3.4 to Memorial Production Partners LP's Registration Statement on Form S-1 (File No. 333-175090) filed on June 23, 2011).

3.6 —Third Amended and Restated Limited Liability Company Agreement of Memorial Production Partners GP LLC (incorporated by reference to Exhibit 3.4 to Memorial Production Partners LP's Quarterly Report on Form 10-Q (File No. 001-35364) filed on August 6, 2014).

4.1 —Indenture, dated July 10, 2014, by and among Memorial Resource Development Corp., the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K (File No. 001-36490) filed on July 16, 2014).

4.2 —Form of 5.875% Senior Note due 2022 (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K (File No. 001-36490) filed on July 16, 2014).

4.3 —Registration Rights Agreement, dated as of July 10, 2014, by and among Memorial Resource Development Corp., the several guarantors named therein and Citigroup Global Markets Inc., as representative of the initial purchasers named therein (incorporated by reference to Exhibit 4.3 to the Company's Current Report on Form 8-K (File No. 001-36490) filed on July 16, 2014).

4.4 —Indenture, dated April 17, 2013, by and among Memorial Production Partners LP, Memorial Production Finance Corporation, the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Memorial Production Partners LP's Current Report on Form 8-K (File No. 001-35364) filed on April 17, 2013).

4.5 —First Supplemental Indenture, dated as of October 7, 2013, by and among Memorial Production Partners LP, Memorial Production Finance Corporation, the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.3 to Memorial Production Partners LP's Quarterly Report on Form 10-Q (File No. 001-35364) filed on November 7, 2013).

4.6 —Registration Rights Agreement, dated July 17, 2014, by and among Memorial Production Partners LP, Memorial Production Finance Corporation, the subsidiary guarantors named therein, and Barclays Capital Inc., as representative of the initial purchasers named therein (incorporated by reference to Exhibit 4.2 to Memorial Production Partners LP's Current Report on Form 8-K (File No. 001-35364) filed on July 17, 2014).

4.7 —Indenture, dated July 17, 2014, by and among Memorial Production Partners LP, Memorial Production Finance Corporation, the subsidiary guarantors named therein and U.S. Bank National Association, as trustee (incorporated by reference to Exhibit 4.1 to Memorial Production Partners LP's Current Report on

Form 8-K (File No. 001-35364) filed on July 17, 2014).

4.8# —Form of Restricted Unit Agreement under the Memorial Production Partners GP LLC Long-Term Incentive Plan (incorporated by reference to Exhibit 4.1 to Memorial Production Partners LP's Registration Statement on Form S-8 (File No. 333-178493) filed on December 4, 2011).

10.1# —Memorial Resource Development Corp. 2014 Long Term Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company's Form 8-K (File No. 001-36490) filed on June 16, 2014).

10.2# —Form of Restricted Unit Agreement under the Memorial Production Partners GP LLC Long-Term Incentive Plan (incorporated by reference to Exhibit 4.6 to Memorial Production Partners LP's Registration Statement on Form S-8 (File No. 333-178493) filed on December 14, 2011).

10.3 —Omnibus Agreement, dated as of December 14, 2011, by and among Memorial Production Partners LP, Memorial Production Partners GP LLC and Memorial Resource Development LLC (incorporated by reference to Exhibit 10.1 to Memorial Production Partners LP's Current Report on Form 8-K (File No. 001-35364) filed on December 15, 2011).

10.4 —Credit Agreement by and among Memorial Resource Development Corp., as the Borrower, the Lenders party thereto, Bank of America, N.A., as Administrative Agent and Collateral Agent, and the other parties party thereto, dated as of June 18, 2014 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-36490) filed on June 24, 2014), as amended by the First Amendment to Credit Agreement by and among Memorial Resource Development Corp., as borrower, Bank of America, N.A., as administrative agent, and the other lenders and parties party thereto, dated as of August 18, 2014 (incorporated by reference to Exhibit 10.6 to the Company's Quarterly Report on Form 10-Q (File No. 001-36490) filed on November 5, 2014); amended by the Second Amendment to Credit Agreement by and among Memorial Resource Development Corp., as borrower, Bank of America, N.A., as administrative agent, and the other lenders and parties party thereto, dated as of October 3, 2014 (incorporated by reference to Exhibit 10.7 to the Company's Quarterly Report on Form 10-Q (File No. 001-36490) filed on November 5, 2014); and as further amended by the Third Amendment to Credit Agreement by and among Memorial Resource Development Corp., as borrower, Bank of America, N.A., as administrative agent, and the other lenders and parties party thereto (incorporated by reference to the Company's Current Report on Form 8-K (File No. 001-36490) filed on December 15, 2014).

10.5 —Credit Agreement, dated as of December 14, 2011, among Memorial Production Operating LLC, as borrower, Memorial Production Partners LP, as parent guarantor, Wells Fargo Bank, National Association, as administrative agent for the lenders party thereto, JPMorgan Chase Bank, N.A., as syndication agent for the lenders party thereto, BNP Paribas, Citibank, N.A. and Comerica Bank, as co-documentation agents for the lenders party thereto, and the other lenders party thereto (incorporated by reference to Exhibit 10.3 to Memorial Production Partners LP's Current Report on Form 8-K (File No. 001-35364) filed on December 15, 2011), as amended by First Amendment to Credit Agreement, dated as of April 30, 2012 (incorporated by reference to Exhibit 10.1 to Memorial Production Partners LP's Quarterly Report on Form 10-Q (File No. 001-35364) filed on May 15, 2012), as further amended by Second Amendment to Credit Agreement, dated as of September 18, 2012 (incorporated by reference to Exhibit 10.1 to Memorial Production Partners LP's Current Report on Form 8-K (File No. 001-35364) filed on September 19, 2012), as further amended by Third Amendment to Credit Agreement, dated as of December 3, 2012 (incorporated by reference to Exhibit 10.1 to Memorial Production Partners LP's Current Report on Form 8-K (File No. 001-35364) filed on December 4, 2012), as further amended by Fourth Amendment to Credit Agreement and First Amendment to Guaranty Agreement, dated as of March 8, 2013 (incorporated by reference to Exhibit 10.1 to Memorial Production Partners LP's Quarterly Report on Form 10-Q (File No. 001-35364) filed on May 10, 2013), as further amended by Fifth Amendment to Credit Agreement, dated as of March 19, 2013 (incorporated by reference to Exhibit 10.1 to Memorial Production Partners LP's Current Report on Form 8-K (File No. 001-35364) filed on March 21, 2013), and as further amended by Sixth Amendment to Credit Agreement, dated as of September 26, 2013 (incorporated by reference to Exhibit 10.1 to Memorial Production Partners LP's Current Report on Form 8-K (File No. 001-35364) filed on October 1, 2013), as further amended by Seventh Amendment to Credit Agreement, dated as of June 13, 2014 (incorporated by reference to Exhibit 10.1 to Memorial Production Partners LP's Current Report on Form 8-K (File No. 001-35364) filed on June 19, 2014), as further amended by Eighth Amendment to Credit Agreement, dated as of October 10, 2014 (incorporated by reference to Exhibit 10.1 to Memorial Production Partners LP's Current Report on Form 8-K (File No. 001-35364) filed on October 14, 2014), and as further amended by Ninth Amendment to Credit Agreement, dated as of December 17, 2014 (incorporated by reference to Exhibit 10.1 to Memorial Production Partners LP's Current Report on Form 8-K (File No. 001-35364) filed on December 18, 2014).

10.6 —Voting Agreement among Memorial Resource Development Corp., MRD Holdco LLC and certain former management members of WildHorse Resources, LLC, dated as of June 18, 2014 (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K (File No. 001-36490) filed on June 24, 2014).

10.7 —Services Agreement among Memorial Resource Development Corp., WildHorse Resources, LLC and WildHorse Resources Management Company, LLC, dated as of June 18, 2014 (incorporated by reference to

Exhibit 10.3 to the Company's Current Report on Form 8-K (File No. 001-36490) filed on June 24, 2014).

10.8 —Registration Rights Agreement among Memorial Resource Development Corp. and certain stockholders, dated as of June 18, 2014 (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K (File No. 001-36490) filed on June 24, 2014).

10.9 —Contribution Agreement among Memorial Resource Development LLC, MRD Holdco LLC and Memorial Resource Development Corp., dated as of June 18, 2014 (incorporated by reference to Exhibit 10.5 to the Company's Form 8-K (File No. 001-36490) filed on June 24, 2014).

10.10 —Contribution Agreement among the former management members of WildHorse Resources, LLC party thereto and Memorial Resource Development Corp., dated as of June 18, 2014 (incorporated by reference to Exhibit 10.6 to the Company's Current Report on Form 8-K (File No. 001-36490) filed on June 24, 2014).

10.11 —Agreement and Plan of Merger merging Memorial Resource Development LLC with and into MRD Operating LLC, dated as of June 18, 2014 (incorporated by reference to Exhibit 10.7 to the Company's Current Report on Form 8-K (File No. 001-36490) filed on June 24, 2014).

10.12 —Purchase Agreement and Assignment between WildHorse Resources, LLC and WildHorse Resources II, LLC, dated as of June 18, 2014 (incorporated by reference to Exhibit 10.8 to the Company's Current Report on Form 8-K (File No. 001-36490) filed on June 24, 2014).

10.13# —Form of Indemnification Agreement between Memorial Resource Development Corp. and each of the officers and directors thereof (incorporated by reference to Exhibit 10.9 to the Company's Current Report on Form 8-K (File No. 001-36490) filed on June 24, 2014).

10.14# —Form of Change in Control Agreement (incorporated by reference to Exhibit 10.10 to the Company's Current Report on Form 8-K (File No. 001-36490) filed on June 24, 2014).

10.15# —Form of Restricted Stock Agreement (incorporated by reference to Exhibit 10.11 to the Company's Current Report on Form 8-K (File No. 001-36490) filed on June 24, 2014).

10.16 —Purchase Agreement, dated as of June 25, 2014, by and among Memorial Resource Development Corp., the subsidiary guarantors named therein and Citigroup Global Markets Inc., as representative of the initial purchasers named therein (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K (File No. 001-36490) filed on June 26, 2014).

10.17 —Service Agreement, dated as of May 1, 2014, between Classic Hydrocarbons Operating, LLC and Classic Pipeline & Gathering, LLC (incorporated by reference to Exhibit 10.11 to Amendment No. 2 to the Company's Registration Statement on Form S-1 (File No. 333-195062) filed on May 27, 2014).

10.18 —Water Disposal Agreement, dated as of May 1, 2014, between Classic Hydrocarbons Operating, LLC and Classic Pipeline & Gathering, LLC (incorporated by reference to Exhibit 10.12 to Amendment No. 2 to the Company's Registration Statement on Form S-1 (File No. 333-195062) filed on May 27, 2014).

10.19 —Purchase Agreement, dated July 14, 2014, by and among Memorial Production Partners LP, Memorial Production Finance Corporation, the subsidiary guarantors named therein, and Barclays Capital Inc., as representative of the several initial purchasers named therein (incorporated by reference to Exhibit 10.1 to Memorial Production Partners LP's Form 8-K (File No. 001-35364) filed on July 15, 2014).

10.20## —Gas Processing Agreement, dated as of March 17, 2014, between WildHorse Resources, LLC and PennTex North Louisiana, LLC (Exhibit 10.10 to Amendment No. 2 to the Company's Registration Statement on Form S-1, filed with the SEC on May 27, 2014).

10.21 —Contribution Agreement among Memorial Resource Development LLC, MRD Holdco LLC and Memorial Resource Development Corp. (incorporated by reference to Exhibit 10.5 to the Company's Form 8-K (File No. 001-36490) filed on June 24, 2014).

10.21 —Contribution Agreement among the WHR stockholders party thereto and Memorial Resource Development Corp. (incorporated by reference to Exhibit 10.6 to the Company's Form 8-K (File No. 001-36490) filed on June 24, 2014).

10.22 —Contribution, Conveyance and Assumption Agreement, dated as of December 14, 2011, by and among Memorial Resource Development LLC, BlueStone Natural Resource Holdings, LLC, BlueStone Natural Resources, LLC, Memorial Production Partners GP LLC, Memorial Production Partners LP and Memorial Production Operating LLC (incorporated by reference to Exhibit 10.4 to Memorial Production Partners LP's Current Report on Form 8-K (File No. 001-35364) filed on December 15, 2011).

10.23	—Purchase and Sale Agreement, dated as of December 14, 2011, by and among Memorial Resource Development LLC, Classic Hydrocarbons Holdings, L.P., Classic Hydrocarbons Operating, LLC, Craton Energy Holdings III, LP, Memorial Production Partners GP LLC, Memorial Production Partners LP and Memorial Production Operating LLC (incorporated by reference to Exhibit 10.5 to Memorial Production Partners LP's Current Report on Form 8-K (File No. 001-35364) filed on December 15, 2011).
10.24	—Contribution, Conveyance and Assumption Agreement, dated as of December 14, 2011, by and among Memorial Resource Development LLC, WHT Energy Partners LLC, Memorial Production Partners GP LLC, Memorial Production Partners LP and Memorial Production Operating LLC (incorporated by reference to Exhibit 10.6 to Memorial Production Partners LP's Current Report on Form 8-K (File No. 001-35364) filed on December 15, 2011).
10.25#	—Memorial Production Partners GP LLC Long-Term Incentive Plan (incorporated by reference to Exhibit 10.7 to Memorial Production Partners LP's Form 8-K (File No. 001-35364) filed on December 15, 2011).
10.26	—Purchase Agreement, dated April 12, 2013, by and among Memorial Production Partners LP, Memorial Production Finance Corporation, the subsidiary guarantors named therein, and Wells Fargo Securities, LLC, as representative of the several initial purchasers named therein (incorporated by reference to Exhibit 10.1 to Memorial Production Partners LP's Current Report on Form 8-K (File No. 001-35364) filed on April 17, 2013).

10.27	—Purchase Agreement, dated May 20, 2013, by and among Memorial Production Partners LP, Memorial Production Finance Corporation, the subsidiary guarantors named therein, and Wells Fargo Securities, LLC, as the initial purchaser (incorporated by reference to Exhibit 10.1 to Memorial Production Partners LP's Current Report on Form 8-K (File No. 001-35364) filed on May 23, 2013).
10.28	—Purchase Agreement, dated October 7, 2013, by and among Memorial Production Partners LP, Memorial Production Finance Corporation, the subsidiary guarantors named therein, and Wells Fargo Securities, LLC, as representative of the several initial purchasers named therein (incorporated by reference to Exhibit 10.1 to Memorial Production Partners LP's Current Report on Form 8-K (File No. 001-35364) filed on October 10, 2013).
21.1*	—Subsidiaries of Memorial Resource Development Corp.
23.1*	—Consent of KPMG LLP, an independent registered public accounting firm.
23.2*	—Consent of Netherland, Sewell & Associates, Inc.
23.3*	—Consent of Ryder Scott Company, L.P.
31.1*	—Certification of Chief Executive Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934
31.2*	—Certification of Chief Financial Officer Pursuant to Rule 13a-14(a)/15d-14(a) of the Securities Exchange Act of 1934
32.1*	—Certifications of Chief Executive Officer and Chief Financial Officer pursuant to 18. U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	—Report of Netherland, Sewell & Associates, Inc.
99.2	—Report of Netherland, Sewell & Associates, Inc. (incorporated by reference to Exhibit 99.1 to Memorial Production Partners LP's Annual Report on Form 10-K (File No. 001-35364) filed on February 26, 2015).
99.3	—Report of Ryder Scott Company L.P. (incorporated by reference to Exhibit 99.2 to Memorial Production Partners LP's Annual Report on Form 10-K (File No. 001-35364) filed on February 26, 2015).
101.CAL*	—XBRL Calculation Linkbase Document
101.DEF*	—XBRL Definition Linkbase Document
101.INS*	—XBRL Instance Document
101.LAB*	—XBRL Labels Linkbase Document
101.PRE*	—XBRL Presentation Linkbase Document
101.SCH*	—XBRL Schema Document

*Filed or furnished as an exhibit to this Annual Report on Form 10-K.
#Management contract or compensatory plan or arrangement.
##Pursuant to Item 601(b)(2) of Regulation S-K, the registrant agrees to furnish supplementally a copy of any omitted exhibit or schedule to the SEC upon request.

SIGNATURES

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

		Memorial Resource Development Corp. (Registrant)	
Date:	March 18, 2015	By:	/s/ Andrew J. Cozby
		Name:	Andrew J. Cozby
		Title:	Senior Vice President and Chief Financial Officer

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

Name	Title (Position with Memorial Resource Development Corp.)	Date
/s/ Tony R. Weber Tony R. Weber	Chairman	March 18, 2015
/s/ John A. Weinzierl John A. Weinzierl	Chief Executive Officer and Director (Principal Executive Officer)	March 18, 2015
/s/ Andrew J. Cozby Andrew J. Cozby	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	March 18, 2015
/s/ Dennis G. Venghaus Dennis G. Venghaus	Vice President and Chief Accounting Officer (Principal Accounting Officer)	March 18, 2015
/s/ Scott A. Gieselman Scott A. Gieselman	Director	March 18, 2015
/s/ Kenneth A. Hersh Kenneth A. Hersh	Director	March 18, 2015
/s/ Robert A. Innamorati Robert A. Innamorati	Director	March 18, 2015
/s/ Carol L. O’Neil Carol L. O’Neil	Director	March 18, 2015

/s/ Pat Wood, III Pat Wood, III	Director	March 18, 2015

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

MEMORIAL RESOURCE DEVELOPMENT CORP.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders

Memorial Resource Development Corp.:

We have audited the accompanying consolidated and combined balance sheets of Memorial Resource Development Corp. and subsidiaries (the Company) as of December 31, 2014 and 2013, and the related consolidated and combined statements of operations, equity, and cash flows for each of the years in the three year period ended December 31, 2014. These consolidated and combined financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated and combined financial statements based on our audits.

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

In our opinion, the consolidated and combined financial statements referred to above present fairly, in all material respects, the financial position of Memorial Resource Development Corp. and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the years in the three year period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 1 to the consolidated and combined financial statements, the balance sheets, and the related statements of operations, equity, and cash flows have been prepared on a combined basis of accounting.

/s/ KPMG LLP

Dallas, Texas
March 18, 2015

MEMORIAL RESOURCE DEVELOPMENT CORP.

CONSOLIDATED AND COMBINED BALANCE SHEETS

(In thousands, except outstanding shares)

	December 31, 2014	2013
ASSETS		
Current assets:		
Cash and cash equivalents	$5,958	$77,721
Restricted cash	—	35,000
Accounts receivable:		
Oil and natural gas sales	82,263	68,764
Joint interest owners and other	49,313	19,958
Affiliates	—	4,652
Short-term derivative instruments	340,056	9,289
Prepaid expenses and other current assets	28,027	19,513
Total current assets	505,617	234,897
Property and equipment, at cost:		
Oil and natural gas properties, successful efforts method	4,844,529	3,037,298
Other	33,815	10,331
Accumulated depreciation, depletion and impairment	(1,340,688)	(627,925)
Property and equipment, net	3,537,656	2,419,704
Long-term derivative instruments	435,369	48,616
Restricted investments	77,361	73,385
Restricted cash	260	15,506
Other long-term assets	37,284	37,053
Total assets	$4,593,547	$2,829,161
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable	$25,772	$20,734
Accounts payable - affiliates	624	1,975
Revenues payable	57,352	56,091
Accrued liabilities	199,000	98,130
Short-term derivative instruments	3,289	9,711
Total current liabilities	286,037	186,641
Long-term debt - MRD Segment	783,000	871,150
Long-term debt - MEMP Segment	1,595,413	792,067
Asset retirement obligations	122,531	111,679
Long-term derivative instruments	—	6,080
Deferred tax liabilities	95,017	3,106
Other long-term liabilities	8,585	306
Total liabilities	2,890,583	1,971,029

Commitments and contingencies (Note 16)		
Equity:		
Stockholders' equity (deficit):		
Preferred stock, $.01 par value: 50,000,000 shares authorized; no shares issued and outstanding	—	—
Common stock, $.01 par value: 600,000,000 shares authorized; 193,435,414 shares issued and outstanding at December 31, 2014; no shares authorized, issued or outstanding at December 31, 2013	1,935	—
Additional paid-in capital	1,367,346	—
Accumulated earnings (deficit)	(786,871)	—
Total stockholders' equity	582,410	—
Members' equity:		
Members	—	237,186
Previous owners (Note 1)	—	40,331
Total members' equity	—	277,517
Noncontrolling interests	1,120,554	580,615
Total equity	1,702,964	858,132
Total liabilities and equity	$4,593,547	$2,829,161

See Accompanying Notes to Consolidated and Combined Financial Statements.

MEMORIAL RESOURCE DEVELOPMENT CORP.

STATEMENTS OF CONSOLIDATED AND COMBINED OPERATIONS

(In thousands, except per share amounts)

	For Year Ended December 31,		
	2014	2013	2012
Revenues:			
Oil & natural gas sales	$894,967	$571,948	$393,631
Other revenues	4,378	3,075	3,237
Total revenues	899,345	575,023	396,868
Costs and expenses:			
Lease operating	161,303	113,640	103,754
Pipeline operating	2,068	1,835	2,114
Exploration	16,603	2,356	9,800
Production and ad valorem taxes	45,751	27,146	23,624
Depreciation, depletion, and amortization	314,193	184,717	138,672
Impairment of proved oil and natural gas properties	432,116	6,600	28,871
Incentive unit compensation expense	943,949	43,279	9,510
General and administrative	87,673	82,079	59,677
Accretion of asset retirement obligations	6,306	5,581	5,009
(Gain) loss on commodity derivative instruments	(749,988)	(29,294)	(34,905)
(Gain) loss on sale of properties	3,057	(85,621)	(9,761)
Other, net	(12)	649	502
Total costs and expenses	1,263,019	352,967	336,867
Operating income (loss)	(363,674)	222,056	60,001
Other income (expense):			
Interest expense, net	(133,833)	(69,250)	(33,238)
Loss on extinguishment of debt	(37,248)	—	—
Amortization of investment premium	—	—	(194)
Other, net	(337)	145	535
Total other income (expense)	(171,418)	(69,105)	(32,897)
Income (loss) before income taxes	(535,092)	152,951	27,104
Income tax benefit (expense)	(100,971)	(1,619)	(107)
Net income (loss)	(636,063)	151,332	26,997
Net income (loss) attributable to noncontrolling interest	126,788	49,830	(2,701)
Net income (loss) attributable to Memorial Resource Development Corp.	(762,851)	101,502	29,698
Net (income) loss allocated to members	(20,305)	(90,712)	7,620
Net (income) loss allocated to previous owners	(1,425)	(10,790)	(37,318)
Net income (loss) available to common stockholders	$(784,581)	$—	$—

Earnings per common share: (Note 10)			
Basic	$(4.08)	$—	$—
Diluted	$(4.08)	$—	$—
Weighted average common and common equivalent shares outstanding:			
Basic	192,498	—	—
Diluted	192,498	—	—

See Accompanying Notes to Consolidated and Combined Financial Statements.

MEMORIAL RESOURCE DEVELOPMENT CORP.

STATEMENTS OF CONSOLIDATED AND COMBINED CASH FLOWS

(In thousands)

	For Year Ended December 31, 2014	2013	2012
Cash flows from operating activities:			
Net income (loss)	$(636,063)	$151,332	$26,997
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion, and amortization	314,193	184,717	138,672
Impairment of proved oil and natural gas properties	432,116	6,600	28,871
(Gain) loss on derivatives	(749,843)	(29,533)	(29,323)
Cash settlements (paid) received on derivative instruments	20,559	30,403	72,045
Cash settlements on terminated derivatives	5,326	—	—
Premiums paid for derivatives	(6,065)	—	(411)
Loss on extinguishment of debt	30,248	—	—
Amortization of deferred financing costs	7,436	8,343	3,584
Accretion of senior notes net discount	2,501	554	—
Amortization of investment premium	—	—	194
Accretion of asset retirement obligations	6,306	5,581	5,009
Amortization of equity awards	10,678	3,557	1,423
(Gain) loss on sale of properties	3,057	(85,621)	(9,761)
Non-cash compensation expense	916,218	1,057	—
Exploration costs	14,953	181	6,980
Deferred income tax expense (benefit)	100,230	76	(312)
Changes in operating assets and liabilities:			
Accounts receivable	(17,635)	(15,758)	(7,382)
Prepaid expenses and other assets	(7,424)	(2,986)	(1,574)
Payables and accrued liabilities	21,208	19,320	5,392
Other	8,272	—	—
Net cash provided by operating activities	476,271	277,823	240,404
Cash flows from investing activities:			
Acquisitions of oil and natural gas properties	(1,177,670)	(105,762)	(360,678)
Additions to oil and gas properties	(674,396)	(360,015)	(273,334)
Additions to other property and equipment	(17,067)	(2,670)	(2,674)
Additions to restricted investments	(3,976)	(5,361)	(4,599)
Deposits for property acquisitions	(215)	—	—
Decrease (increase) in restricted cash	49,946	(49,347)	(3)
Proceeds from the sale of oil and natural gas properties	6,700	155,712	34,521
Other	(301)	—	29
Net cash used in investing activities	(1,816,979)	(367,443)	(606,738)
Cash flows from financing activities:			
Advances on revolving credit facilities	2,746,800	1,132,755	619,450
Payments on revolving credit facilities	(2,457,900)	(1,766,037)	(251,569)

Proceeds from the issuances of senior notes	1,092,425	1,031,563	—
Redemption of senior notes	(351,808)	—	—
Borrowings under second lien credit facility	—	325,000	—
Redemption of second lien credit facility	(328,282)	—	—
Deferred financing costs	(30,334)	(41,175)	(3,501)
Proceeds from initial public offering	408,500	—	—
Costs incurred in conjunction with initial public offering	(28,373)	—	—
Proceeds from MEMP public offering	553,288	511,204	202,573
Costs incurred in conjunction with MEMP public offering	(12,510)	(21,066)	(8,268)
Proceeds from changes in ownership interests in MEMP	—	135,012	—
Repurchased shares under repurchase program	(161)	—	—
Repurchases under MEMP unit repurchase program	(11,531)	—	—
Restricted MEMP units returned to plan	(1,012)	—	—
Purchase of additional interests in consolidated subsidiaries	(3,292)	(15,135)	—
Contributions from previous owners	—	1,214	44,072
Contributions from NGP affiliates related to sale of properties	1,165	2,013	45,158
Distributions to the Funds	—	(732,362)	—
Distributions to MRD Holdco	(59,803)	—	—
Distributions to noncontrolling interests	(149,084)	(78,083)	(15,208)
Distribution to NGP affiliates related to purchase of assets	(66,693)	(355,494)	(242,174)
Distribution to NGP affiliates related to sale of assets, net of cash received	(32,770)	—	—
Distributions made by previous owners	—	(4,005)	(28,772)
Cash retained by previous owners	—	(7,909)	—
Other	320	455	—
Net cash provided by financing activities	1,268,945	117,950	361,761
Net change in cash and cash equivalents	(71,763)	28,330	(4,573)
Cash and cash equivalents, beginning of period	77,721	49,391	53,964
Cash and cash equivalents, end of period	$5,958	$77,721	$49,391

See Accompanying Notes to Consolidated and Combined Financial Statements.

See Supplemental cash flow information (Note 2)

MEMORIAL RESOURCE DEVELOPMENT CORP.

STATEMENTS OF CONSOLIDATED AND COMBINED EQUITY

(In thousands)

	Members' Equity			
	Members	Previous Owners	Noncontrolling Interest	Total
Balance, December 31, 2011	$853,436	$261,340	$ 161,588	$1,276,364
Net income (loss)	(7,620)	37,318	(2,701)	26,997
Contributions	—	44,072	—	44,072
Contribution of oil and gas properties from NGP affiliate	—	6,893	—	6,893
Net proceeds from MEMP public equity Offering	—	—	194,134	194,134
Distributions	—	(28,772)	(15,255)	(44,027)
Net book value of net assets acquired from affiliates	52,217	(93,696)	41,479	—
Amortization of MEMP equity awards	—	—	1,423	1,423
Noncontrolling interest's share of net book value in excess of consideration received from sale of assets to MEMP	727	—	(727)	—
Contribution related to sale of assets to NGP affiliate	6,291	40,138	742	47,171
Net book value of assets acquired by NGP affiliate	(579)	(33,859)	(68)	(34,506)
Distribution to affiliate in connection with acquisition of assets	(134,964)	—	(107,210)	(242,174)
Impact from equity transactions of MEMP	41,930	—	(41,930)	—
Other	176	(1)	187	362
Balance, December 31, 2012	811,614	233,433	231,662	1,276,709
Net income (loss)	90,712	10,790	49,830	151,332
Contributions	—	1,214	—	1,214
Net Proceeds from MEMP public equity offering	—	—	490,138	490,138
Sale of MEMP common units	60,701	—	74,311	135,012
Distributions	(732,362)	(4,005)	(78,083)	(814,450)
Net book value of net assets acquired from affiliates	50,751	(181,556)	130,805	—
Amortization of MEMP equity awards	—	—	3,558	3,558
Noncontrolling interest's share of cash consideration received in excess of the net book value sold to MEMP	(24)	—	24	—
Distribution to affiliate in connection with acquisition of assets	(98,180)	—	(253,055)	(351,235)
Purchase of noncontrolling interests	(303)	—	(14,832)	(15,135)
Impact of equity transactions of MEMP	54,183	—	(54,183)	—
Other	94	(2,299)	440	(1,765)
Net assets retained by previous owners	—	(17,246)	—	(17,246)
Balance, December 31, 2013	$237,186	$40,331	$ 580,615	$858,132

Continued

See Accompanying Notes to Consolidated and Combined Financial Statements.

MEMORIAL RESOURCE DEVELOPMENT CORP.

STATEMENTS OF CONSOLIDATED AND COMBINED EQUITY CONTINUED

(In thousands)

	Stockholders' Equity			Members' Equity			
	Common stock	Additional paid in capital	Accumulated earnings (deficit)	Members	Previous Owners	Noncontrolling Interest	Total
Balance, December 31, 2013	$—	$—	$—	$237,186	$40,331	$580,615	$858,132
Net income (loss)	—	—	(784,581)	20,305	1,425	126,788	(636,063)
Issuance of shares in connection with restructuring transactions (Note 1)	1,710	913,152	—	—	—	—	914,862
Issuance of shares in connection with initial public offering (Note 1)	215	379,962	—	—	—	—	380,177
Tax related effects in connection with restructuring transactions and initial public offering	—	(43,251)	—	—	—	—	(43,251)
Share repurchase	(1)	—	(2,214)	—	—	—	(2,215)
Restricted stock awards	11	(11)	—	—	—	—	—
Amortization of restricted stock awards	—	2,804	—	—	—	—	2,804
Contribution related to MRD Holdco incentive unit compensation expense (Note 12)	—	111,866	—	—	—	—	111,866
Purchase of noncontrolling interests	—	(2,881)	—	—	—	(411)	(3,292)
Contribution related to sale of assets to NGP affiliate	—	—	—	1,165	—	—	1,165
Net book value of assets sold to NGP affiliate	—	—	—	(621)	—	—	(621)
Net book value of assets acquired from NGP affiliates	—	—	—	45,059	(41,756)	—	3,303
Distribution to NGP affiliates in connection with acquisition of assets	—	—	—	(66,693)	—	—	(66,693)
	—	—	—	(123,078)	—	29,994	(93,084)

Distribution of net assets to MRD Holdco							
Distribution of shares received in connection with restructuring transactions to MRD Holdco	—	—	—	(110,510)	—	—	(110,510)
Net equity deemed contribution (distribution) related to net assets transferred to MEMP	—	5,327	—	(2,659)	—	(2,668)	—
Net proceeds from MEMP public equity offering	—	—	—	—	—	540,698	540,698
Distributions	—	—	—	—	—	(149,084)	(149,084)
Amortization of MEMP equity awards	—	—	—	—	—	7,874	7,874
MEMP common units repurchased	—	—	—	—	—	(12,903)	(12,903)
MEMP restricted units repurchased	—	—	—	—	—	(1,012)	(1,012)
Other	—	378	(76)	(154)	—	663	811
Balance, December 31, 2014	$1,935	$1,367,346	$(786,871)	$—	$—	$1,120,554	$1,702,964

See Accompanying Notes to Consolidated and Combined Financial Statements.

MEMORIAL RESOURCE DEVELOPMENT CORP.

NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

Note 1. Organization and Basis of Presentation

Overview

Memorial Resource Development Corp. (the "Company") is a publicly traded Delaware corporation, the common shares of which are listed on the NASDAQ Global Market ("NASDAQ") under the symbol "MRD." Unless the context requires otherwise, references to "we," "us," "our," "MRD," or "the Company" are intended to mean the business and operations of Memorial Resource Development Corp. and its consolidated subsidiaries.

The Company was formed by Memorial Resource Development LLC ("MRD LLC") in January 2014 to acquire, explore and develop natural gas and oil properties in North America. MRD LLC was a Delaware limited liability company formed on April 27, 2011 by Natural Gas Partners VIII, L.P. ("NGP VIII"), Natural Gas Partners IX, L.P. ("NGP IX") and NGP IX Offshore Holdings, L.P. ("NGP IX Offshore") (collectively, the "Funds") to explore, develop and acquire natural gas and oil properties. The Funds are private equity funds managed by Natural Gas Partners ("NGP"). MRD LLC's consolidated and combined financial statements represent our predecessor for accounting and financial reporting purposes prior to our initial public offering.

Initial Public Offering and Restructuring Transactions

On June 18, 2014, the Company completed its initial public offering of 21,500,000 common units at a price of $19.00 per share, which generated net proceeds to the Company of approximately $380.2 million after deducting underwriting discounts and commissions and other offering related fees and expenses. The following restructuring events and transactions occurred in connection with our initial public offering:

The Funds contributed all of their interests in MRD LLC to MRD Holdco LLC ("MRD Holdco") and the members of our management who owned incentive units in MRD LLC exchanged those incentive units for substantially identical incentive units in MRD Holdco, after which MRD Holdco owned 100% of MRD LLC;

WildHorse Resources, LLC ("WildHorse Resources") sold its subsidiary, WildHorse Resources Management Company, LLC ("WHR Management Company"), to an affiliate of the Funds for approximately $0.2 million in cash, and WHR Management Company entered into a services agreement with the Company and WildHorse Resources pursuant to which WHR Management Company agreed to provide certain management services to WildHorse Resources, which was terminated as of March 1, 2015;

Classic Hydrocarbons Holdings, L.P. ("Classic") and Classic Hydrocarbons GP Co., L.L.C. ("Classic GP") distributed to MRD LLC the ownership interests in Classic Pipeline & Gathering, LLC ("Classic Pipeline"), which owns certain midstream assets in Texas, and Black Diamond Minerals, LLC ("Black Diamond") distributed to MRD LLC its ownership interests in Golden Energy Partners LLC ("Golden Energy"), which sold all of its assets in May 2014;

MRD LLC contributed to us substantially all of its assets, comprised of: (i) 100% of the ownership interests in Classic, Classic GP, Black Diamond, Beta Operating Company, LLC ("Beta Operating"), Memorial Resource Finance Corp., MRD Operating LLC ("MRD Operating"), Memorial Production Partners GP LLC ("MEMP GP") (including MEMP GP's ownership of 50% of Memorial Production Partners LP's ("MEMP") incentive distribution rights) and (ii) 99.9% of the membership interests in WildHorse Resources;

We issued 128,665,677 shares of our common stock to MRD LLC, which MRD LLC immediately distributed to MRD Holdco;

We assumed the obligations of MRD LLC under the indenture governing the $350 million in aggregate principal amount of 10.00% / 10.75% Senior PIK Toggle Notes due 2018 (the "PIK notes") and reimbursed MRD LLC for the

June 15, 2014 interest payment made on the PIK notes;

Certain former management members of WildHorse Resources contributed to us their outstanding incentive units in WildHorse Resources, as well as the remaining 0.1% of the membership interests in WildHorse Resources, and we issued 42,334,323 shares of our common stock and paid cash consideration of $30.0 million to such former management members of WildHorse Resources;

MEMORIAL RESOURCE DEVELOPMENT CORP.

NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

We entered into a registration rights agreement and a voting agreement with MRD Holdco and certain former management members of WildHorse Resources;

We entered into a new $2.0 billion revolving credit facility (see Note 8) and used approximately $614.5 million in borrowings under that facility to repay all amounts outstanding under WildHorse Resources' credit agreements, to partially fund the cash consideration payable to the former management members of WildHorse Resources and to reimburse MRD LLC for the June 15, 2014 interest payment made on the PIK notes;

Notice of redemption was given to the PIK notes trustee (see Note 8) specifying a redemption date of July 16, 2014 and indicating that a portion of the net proceeds from our initial public offering, which temporarily reduced amounts outstanding under our new revolving credit facility, would be used to redeem the PIK notes at a redemption price of 102% of the principal amount of the PIK notes plus accrued and unpaid interest thereon to the date of redemption;

MRD Operating entered into a merger agreement with MRD LLC pursuant to which after the termination or earlier discharge of the PIK notes MRD LLC would merge into MRD Operating;

MRD LLC distributed to MRD Holdco the following: (i) BlueStone Natural Resources Holdings, LLC ("BlueStone"), which sold substantially all of its assets in July 2013 for $117.9 million, MRD Royalty LLC, which owns certain leasehold interests and overriding royalty interests in Texas and Montana, MRD Midstream LLC, which owns an indirect interest in certain midstream assets in North Louisiana, Golden Energy and Classic Pipeline; (ii) 5,360,912 subordinated units of MEMP; (iii) the right to the remaining cash to be released from the debt service reserve account in connection with the redemption or earlier discharge of the PIK notes plus the cash received from us in reimbursement of the interest paid on June 15, 2014 in respect of the PIK notes; and (iv) approximately $6.7 million of cash received by MRD LLC in connection with the sale of Golden Energy's assets in May 2014;

We irrevocably deposited with the PIK notes trustee approximately $360.0 million on June 27, 2014, which was an amount sufficient to fund the redemption of the PIK notes on the redemption date and to satisfy and discharge our obligations under the PIK notes and the related indenture. The discharge became effective upon the irrevocable deposit of the funds with the PIK notes trustee; and

MRD LLC merged into MRD Operating.

Previous Owners

References to "the previous owners" for accounting and financial reporting purposes refer collectively to:

Certain oil and natural gas properties and related assets primarily in the Permian Basin, East Texas and the Rockies that MEMP acquired through equity transactions in October 2013 from certain affiliates of NGP. In October 2013, MEMP acquired Boaz Energy, LLC ("Boaz"), Crown Energy Partners, LLC ("Crown"), the Crown net profits interest and overriding royalty interest ("Crown NPI/ORRI"), Propel Energy SPV LLC ("Propel SPV"), together with its wholly-owned subsidiary Propel Energy Services, LLC ("Propel Energy Services"), and Stanolind Oil and Gas SPV LLC ("Stanolind SPV") from Boaz Energy Partners, LLC ("Boaz Energy Partners"), Crown Energy Partners Holdings, LLC ("Crown Holdings"), Propel Energy, LLC ("Propel Energy") and Stanolind Oil and Gas LP ("Stanolind"), all of which are primarily owned by two of the Funds.

A net profits interest that WildHorse Resources purchased from NGP Income Co-Investment Fund II, L.P. ("NGPCIF") in February 2014 ("NGPCIF NPI"). NGPCIF is controlled by NGP. Upon the completion of the 2010 Petrohawk and Clayton Williams acquisitions, WildHorse Resources sold a net profits interest in these properties to NGPCIF. Since WildHorse Resources sold the net profits interest, the historical results are accounted for as a working interest for all periods.

Our audited financial statements reported herein include the financial position and results attributable to: (i) those certain oil and natural gas properties and related assets that MEMP acquired through equity transactions in October 2013 from Boaz Energy Partners, Crown Holdings, Propel Energy and Stanolind and (ii) NGPCIF NPI.

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MEMORIAL RESOURCE DEVELOPMENT CORP.

NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

Basis of Presentation

The financial statements reported herein include the financial position and results attributable to both our predecessor and the previous owners on a combined basis for periods prior to our initial public offering. For periods after the completion of our public offering, our consolidated financial statements include our accounts and those of our subsidiaries in which we have a controlling interest. Due to our control of MEMP through our ownership of MEMP GP, we are required to consolidate MEMP for accounting and financial reporting purposes. MEMP is owned 99.9% by its limited partners and 0.1% by MEMP GP.

All material intercompany transactions and balances have been eliminated in preparation of our consolidated and combined financial statements. The accompanying consolidated and combined financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP").

We have two reportable business segments, both of which are engaged in the acquisition, exploration, development and production of oil and natural gas properties (See Note 14). Our reportable business segments are as follows:

MRD—reflects the combined operations of the Company, MRD Operating, MRD LLC, WildHorse Resources and its previous owners, Classic and Classic GP, Black Diamond, BlueStone, Beta Operating and MEMP GP.
MEMP—reflects the combined operations of MEMP, its previous owners, and historical dropdown transactions that occurred between MEMP and other MRD LLC consolidating subsidiaries.

Segment financial information has been retrospectively revised for the following common control transactions for comparability purposes:

- acquisition by MEMP of all the outstanding membership interests in Tanos Energy, LLC ("Tanos") from MRD LLC for a purchase price of approximately $77.4 million on October 1, 2013;
- acquisition by MEMP of all the outstanding membership interests in Prospect Energy, LLC ("Prospect Energy") from Black Diamond for a purchase price of approximately $16.3 million on October 1, 2013;
- acquisition by MEMP of certain of the oil and natural gas properties in Jackson County, Texas from MRD LLC for a purchase price of approximately $2.6 million on October 1, 2013;
- acquisition by MEMP of all the outstanding membership interests in WHT Energy Partners LLC ("WHT") from WildHorse Resources and Tanos for a purchase price of approximately $200.0 million on March 28, 2013;
- acquisition by MEMP of certain assets from Classic in East Texas in May 2012 for a purchase price of approximately $27.0 million; and
- acquisition by MEMP of certain assets from Tanos in East Texas in April 2012 for a purchase price of approximately $18.5 million.

Note 2. Summary of Significant Accounting Policies

Use of Estimates

The preparation of consolidated and combined financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated and combined financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimates.

Significant estimates include, but are not limited to, oil and natural gas reserves; depreciation, depletion, and amortization of proved oil and natural gas properties; future cash flows from oil and natural gas properties; impairment of long-lived assets; fair value of derivatives; fair value of equity and incentive unit compensation; fair values of assets acquired and liabilities assumed in business combinations and asset retirement obligations.

MEMORIAL RESOURCE DEVELOPMENT CORP.

NOTES TO CONSOLIDATED AND COMBINED FINANCIAL STATEMENTS

Principles of Consolidation and Combination

Our consolidated financial statements include our accounts and those of our subsidiaries in which we have a controlling interest, after the elimination of all intercompany accounts and transactions. Likewise, the combined financial statements include the accounts of our predecessor and the previous owners as discussed above. All material intercompany balances and transactions have been eliminated. Certain prior period balances have been reclassified to better align with financial statement presentation in the current fiscal year.

Cash and Cash Equivalents

Cash and cash equivalents represent unrestricted cash on hand and all highly liquid investments with original contractual maturities of three months or less.

Book Overdrafts

Book overdrafts, representing outstanding checks in excess of funds on deposit, are classified as accounts payable and the change in the related balance is reflected in operating activities in the statement of cash flows.

Concentrations of Credit Risk

Cash balances, accounts receivable, restricted investments and derivative financial instruments are financial instruments potentially subject to credit risk. Cash and cash equivalents are maintained in bank deposit accounts which, at times, may exceed the federally insured limits. Management periodically reviews and assesses the financial condition of the banks to mitigate the risk of loss. Various restricted investment accounts fund certain long-term contractual and regulatory asset retirement obligations and collateralize certain regulatory bonds associated with MEMP's offshore Southern California oil and gas properties. These restricted investments may consist of money market deposit accounts, money market mutual funds, commercial paper, and U.S. Government securities, all held with credit-worthy financial institutions. Derivative financial instruments are generally executed with major financial institutions that expose us to market and credit risks and which may, at times, be concentrated with certain counterparties. The credit worthiness of the counterparties is subject to continual review. We rely upon netting arrangements with counterparties to reduce credit exposure. Neither we nor our predecessor and the previous owners have experienced any losses from such instruments.

Oil and natural gas are sold to a variety of purchasers, including intrastate and interstate pipelines or their marketing affiliates and independent marketing companies. Accounts receivable from joint operations are from a number of oil and natural gas companies, partnerships, individuals, and others who own interests in the properties operated by us, our predecessor, and the previous owners. Generally, operators of crude oil and natural gas properties have the right to offset future revenues against unpaid charges related to operated wells, minimizing the credit risk associated with these receivables. Additionally, management believes that any credit risk imposed by a concentration in the oil and natural gas industry is mitigated by the creditworthiness of its customer base. An allowance for doubtful accounts is recorded after all reasonable efforts have been exhausted to collect or settle the amount owed. Any amounts outstanding longer than the contractual terms are considered past due. Management determined that an allowance for uncollectible accounts was unnecessary at both December 31, 2014 and 2013, respectively.

If we were to lose any one of our customers, the loss could temporarily delay the production and the sale of oil and natural gas in the related producing region. If we were to lose any single customer, we believe that a substitute customer to purchase the impacted production volumes could be identified.

Oil and Natural Gas Properties

Oil and natural gas exploration, development and production activities are accounted for in accordance with the successful efforts method of accounting. Under this method, costs of acquiring properties, costs of drilling successful exploration wells, and development costs are capitalized. The costs of exploratory wells are initially capitalized pending a determination of whether proved reserves have been found. At the completion of drilling activities, the costs of exploratory wells remain capitalized if determination is made that proved reserves have been found. If no proved reserves have been found, the costs of each of the related exploratory wells are charged to expense. In some cases, a determination of proved reserves cannot be made at the completion of drilling, requiring additional testing and evaluation of the wells. The costs of such exploratory wells are expensed if a determination of proved reserves has not been made within a twelve-month period after drilling is complete. Exploration costs such as geological, geophysical, and seismic costs are expensed as incurred.

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As exploration and development work progresses and the reserves on these properties are proven, capitalized costs attributed to the properties are subject to depreciation and depletion. Depletion of capitalized costs is provided using the units-of-production method based on proved oil and gas reserves related to the associated field. Capitalized drilling and development costs of producing oil and natural gas properties are depleted over proved developed reserves and leasehold costs are depleted over total proved reserves.

On the sale or retirement of a complete or partial unit of a proved property or pipeline and related facilities, the cost and related accumulated depreciation, depletion, and amortization are removed from the property accounts, and any gain or loss is recognized.

There were no material capitalized exploratory drilling costs pending evaluation at December 31, 2014, 2013 and 2012.

Oil and Gas Reserves

The estimates of proved oil and natural gas reserves utilized in the preparation of the consolidated and combined financial statements are estimated in accordance with the rules established by the SEC and the Financial Accounting Standards Board (“FASB”). These rules require that reserve estimates be prepared under existing economic and operating conditions using a trailing 12-month average price with no provision for price and cost escalations in future years except by contractual arrangements. Netherland, Sewell & Associates, Inc. (“NSAI”), our independent reserve engineers, was engaged to audit our internally prepared reserves estimates at December 31, 2014. MEMP engaged NSAI and Ryder Scott Company, L.P. to audit MEMP’s internally prepared reserves estimates for all of MEMP’s proved reserves (by volume) at December 31, 2014.

Reserve estimates are inherently imprecise. Accordingly, the estimates are expected to change as more current information becomes available. It is possible that, because of changes in market conditions or the inherent imprecision of reserve estimates, the estimates of future cash inflows, future gross revenues, the amount of oil and natural gas reserves, the remaining estimated lives of oil and natural gas properties, or any combination of the above may be increased or decreased. Increases in recoverable economic volumes generally reduce per unit depletion rates while decreases in recoverable economic volumes generally increase per unit depletion rates.

Other Property & Equipment

Other property and equipment is stated at historical cost and is comprised primarily of vehicles, furniture, fixtures, office build-out cost and computer hardware and software. Depreciation of other property and equipment is calculated using the straight-line method generally based on estimated useful lives of three to seven years.

Asset Retirement Obligations

An asset retirement obligation associated with retiring long-lived assets is recognized as a liability on a discounted basis in the period in which the legal obligation is incurred and becomes determinable, with an equal amount capitalized as an addition to oil and natural gas properties, which is allocated to expense over the useful life of the asset. Generally, oil and gas producing companies incur such a liability upon acquiring or drilling a well. Accretion expense is recognized over time as the discounted liabilities are accreted to their expected settlement value. Upon settlement of the liability, a gain or loss is recognized in net income (loss) to the extent the actual costs differ from the recorded liability. See Note 6 for further discussion of asset retirement obligations.

Impairments

Proved oil and natural gas properties are reviewed for impairment when events and circumstances indicate the carrying value of such properties may not be recoverable. This may be due to a downward revision of the reserve estimates, less than expected production, drilling results, higher operating and development costs, or lower commodity prices. The estimated undiscounted future cash flows expected in connection with the property are compared to the carrying value of the property to determine if the carrying amount is recoverable. If the carrying value of the property exceeds its estimated undiscounted future cash flows, the carrying amount of the property is reduced to its estimated fair value using Level 3 inputs. The factors used to determine fair value include, but are not limited to, estimates of proved reserves, future commodity prices, the timing of future production and capital expenditures and a discount rate commensurate with the risk reflective of the lives remaining for the respective oil and gas properties. Impairment expense for the years ended December 31, 2014, 2013, and 2012 was approximately \$432.1 million, \$6.6 million, \$28.9 million, respectively. See Note 4 for further discussion on impairments.

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Restricted Investments

Various restricted investment accounts fund certain long-term contractual and regulatory asset retirement obligations and collateralize certain regulatory bonds associated with MEMP's offshore Southern California oil and gas properties. These investments are classified as held-to-maturity, and such investments are stated at amortized cost. Interest earned on these investments is included in interest expense – net in the statement of operations. The amortized cost of such investments is adjusted for amortization of premiums and accretion of discounts to maturity. Such amortization and accretion is displayed as a separate line item in the statement of operations. These restricted investments consist of money market deposit accounts, money market mutual funds, commercial paper, and U.S. Government securities. See Note 7 for additional information.

Debt Issuance Costs

These costs are recorded on the balance sheet and amortized over the term of the associated debt using the straight-line method which generally approximates the effective yield method. Amortization expense, including write-off of debt issuance costs, for the years ended December 31, 2014, 2013, and 2012 was approximately $7.4 million, $8.3 million and $3.6 million, respectively.

Revenue Recognition

Revenue from the sale of oil and natural gas is recognized when title passes, net of royalties due to third parties. Oil and natural gas revenues are recorded using the sales method. Under this method, revenues are recognized based on actual volumes of oil and natural gas sold to purchasers, regardless of whether the sales are proportionate to our ownership in the property. An asset or a liability is recognized to the extent there is an imbalance in excess of the proportionate share of the remaining recoverable reserves on the underlying properties. No significant imbalances existed at December 31, 2014 or 2013.

The following individual customers each accounted for 10% or more of total reported revenues for the period indicated:

	Years Ending December 31,		
	2014	2013	2012
Consolidated & Combined:			
Energy Transfer Equity, L.P. and subsidiaries	33 %	35 %	13 %
MRD Segment:			
Energy Transfer Equity, L.P. and subsidiaries	73 %	77 %	39 %
Sunoco, Inc. (1)	n/a	n/a	15 %
Dominion Gas Ventures LP	n/a	n/a	15 %
MEMP Segment:			
Sinclair Oil & Gas Company	12 %	n/a	n/a
Phillips 66 (2)	13 %	15 %	13 %
ConocoPhillips	n/a	n/a	14 %

(1) Sunoco, Inc. became a subsidiary of Energy Transfer Equity, L.P. in October 2012.
(2) Phillips 66 was a subsidiary of ConocoPhillips through April 30, 2012. Accordingly, any revenues generated from Phillips 66 prior to May 1, 2012 were reported under ConocoPhillips.

Derivative Instruments

Commodity derivative financial instruments (e.g., swaps, collars, and put options) are used to reduce the impact of natural gas, NGL and oil price fluctuations. Interest rate swaps are used to manage exposure to interest rate volatility, primarily as a result of variable rate borrowings under the credit facilities. Every derivative instrument is recorded on the balance sheet as either an asset or liability measured at its fair value. Changes in the derivative's fair value are recognized in earnings as we have not elected hedge accounting for any of our derivative positions.

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Capitalized Interest

We capitalize interest costs to oil and gas properties on expenditures made in connection with certain projects such as drilling and completion of new oil and natural gas wells and major facility installations. Interest is capitalized only for the period that such activities are in progress. Interest is capitalized using a weighted average interest rate based on our outstanding borrowings. These capitalized costs are included within intangible drilling costs and amortized using the units of production method. For the year ended December 31, 2014, we capitalized $7.3 million of interest. We did not capitalize any interest in 2013 or 2012.

Income Tax

Prior to our initial public offering, MRD LLC was organized as a pass-through entity for federal income tax purposes and was not subject to federal income taxes; however, certain of its consolidating subsidiaries were taxed as corporations and subject to federal income taxes. We are organized as a taxable C corporation and subject to federal and certain state income taxes. We are also subject to the Texas margin tax and certain aspects of the tax make it similar to an income tax.

The Company accounts for income taxes using the asset and liability method wherein deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. Deferred tax assets are reduced by a valuation allowance if, based on the weight of available evidence, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

We must recognize the tax effects of any uncertain tax positions we may adopt, if the position taken by us is more likely than not sustainable based on its technical merits. If a tax position meets such criteria, the tax effect that would be recognized by us would be the largest amount of benefit with more than 50% chance of being realized.

The evaluation of uncertain tax positions is a two-step process. The first step is a recognition process to determine whether it is more likely than not that a tax position will be sustained upon examination, including resolution of any related appeals or litigation processes, based on the technical merits of the position. In evaluating whether a tax position has met the more likely than not recognition threshold, it is presumed that the position will be examined by the appropriate taxing authority with full knowledge of all relevant information. The second step is a measurement process whereby a tax position that meets the more likely than not recognition threshold is calculated to determine the amount of benefit/expense to recognize in the consolidated financial statements. The tax position is measured at the largest amount of benefit/expense that is more likely than not of being realized upon ultimate settlement.

The Company has no liability for unrecognized tax benefits as of December 31, 2014 and 2013. Accordingly, there is no amount of unrecognized tax benefits that, if recognized, would affect the effective tax rate and there is no amount of interest or penalties currently recognized in the consolidated statements of operations or consolidated balance sheets as of December 31, 2014. In addition, the Company does not believe that there are any positions for which it is reasonably possible that the total amount of unrecognized tax benefits will significantly increase or decrease within the next twelve months.

In June 2014, we recorded a deferred tax liability of approximately $43.3 million in stockholders' equity in connection with our initial public offering and the related restructuring transactions. The tax bases of our assets and liabilities changed as a result our initial public offering and the related restructuring transactions, which represented a transaction among stockholders.

Tax audits may be ongoing at any point in time. Tax liabilities are recorded based on estimates of additional taxes which may be due upon the conclusion of these audits. Estimates of these tax liabilities are made based upon prior experience and are updated for changes in facts and circumstances. However, due to the uncertain and complex application of tax regulations, it is possible that the ultimate resolution of audits may result in liabilities which could be materially different from these estimates. See Note 15 for additional information.

Earnings Per Share

Basic earnings per share ("EPS") is computed using the two-class method based on net income (loss) available to common stockholders and the average number of shares of common stock outstanding for the period. Diluted EPS includes the impact of the Company's restricted shares of common stock as they are participating securities. The Company determines the more dilutive of either the two-class method or the treasury stock method for diluted EPS. See Note 10 for additional information.

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Incentive Based Compensation Arrangements

The fair value of equity-classified awards (e.g., restricted stock awards) is amortized to earnings over the requisite service or vesting period. Compensation expense for liability-classified awards are recognized over the requisite service or vesting period of an award based on the fair value of the award re-measured at each reporting period. Generally, no compensation expense is recognized for equity instruments that do not vest.

Prior to the restructuring transactions, the governing documents of MRD LLC and certain of its subsidiaries provided for the issuance of incentive units. The incentive units were subject to performance conditions that affected their vesting. Compensation cost was recognized only if the performance condition was probable of being satisfied at each reporting date.

In connection with the restructuring transactions, the MRD LLC incentive units were exchanged for substantially identical units in MRD Holdco, and such incentive units entitle holders thereof to portions of future distributions by MRD Holdco. While any such distributions made by MRD Holdco will not involve any cash payment by us, we will be required to recognize non-cash compensation expense, which may be material, in future periods. The compensation expense recognized by us related to the incentive units will be offset by a deemed capital contribution from MRD Holdco as they are remeasured at the end of each reporting period.

See Notes 11 and 12 for further information.

Accrued Liabilities

Current accrued liabilities consisted of the following at the dates indicated (in thousands):

	December 31,	
	2014	2013
Accrued capital expenditures	$80,350	$48,579
Accrued lease operating expense	16,403	13,240
Accrued general and administrative expenses	8,516	14,485
Accrued ad valorem and production taxes	8,870	3,541
Accrued interest payable	24,797	11,934
Accrued environmental	2,092	577
Accrued current deferred income taxes	51,929	382
Other miscellaneous, including operator advances	6,043	5,392
	$199,000	$98,130

Supplemental Cash Flow Information

Supplemental cash flow for the periods presented (in thousands):

	For Year Ended December 31,		
	2014	2013	2012

Supplemental cash flows:			
Cash paid for interest, net of amounts capitalized	$130,732	$61,140	$23,525
Income tax paid	838	168	22
Noncash investing and financing activities:			
Change in capital expenditures in payables and accrued liabilities	31,771	41,017	17,158
Assumptions of asset retirement obligations related to properties acquired or drilled	5,420	4,227	7,962
Contribution of oil and gas properties from NGP affiliate	—	—	6,893
Accrued distribution to NGP affiliates related to Cinco Group acquisitions	—	4,352	—
Contribution related to sale of assets to NGP affiliate - restricted cash	—	—	2,013
Accrued equity offering costs	—	—	171
Distributions to noncontrolling interests	—	—	47
Repurchase of equity under repurchase program	3,425	—	—
Accounts receivable related to acquisitions	9,569	—	—

New Accounting Pronouncements

Revenue from Contracts with Customers. In May 2014, the FASB issued a comprehensive new revenue recognition standard for contracts with customers that will supersede most current revenue recognition guidance, including industry-specific guidance. The core principle of this standard is that an entity should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. To achieve this core principle, the standard provides a five-step analysis of transactions to determine when and how revenue is recognized. Other major provisions include the capitalization and amortization of certain contract costs, ensuring the time value of money is considered in the transaction price, and allowing estimates of variable consideration to be recognized before contingencies are resolved in certain circumstances. This guidance also requires enhanced disclosures regarding the nature, amount, timing and uncertainty of revenue and cash flows arising from an entity's contracts with customers. The new standard is effective for fiscal years, and interim periods within those years, beginning after December 15, 2016. Early application is prohibited. The standard permits the use of either the retrospective or cumulative effect transition method. This guidance will be applicable to the Company beginning on January 1, 2017. The Company is currently assessing the impact that adopting this new accounting guidance will have on its consolidated financial statements and footnote disclosures.

Reporting Discontinued Operations. In April 2014, the FASB issued an accounting standards update that changes the criteria for determining when disposals can be presented as discontinued operations and modifies discontinued operations disclosures. The new guidance now defines a "discontinued operation" as (i) a disposal of a component or group of components that is disposed of or is classified as held for sale and "represents a strategic shift that has (or will have) a major effect on an entity's operations and financial results" or (ii) an acquired business or nonprofit activity that is classified as held for sale on the date of acquisition. We will adopt this guidance and apply the disclosure requirements prospectively beginning on January 1, 2015.

Amendments to Consolidation Analysis. In February 2015, the FASB issued an accounting standards update to improve consolidation guidance for certain types of legal entities. The guidance modifies the evaluation of whether limited partnerships and similar legal entities are variable interest entities ("VIEs") or voting interest entities, eliminates the presumption that a general partner should consolidate a limited partnership, affects the consolidation analysis of reporting entities that are involved with VIEs, particularly those that have fee arrangements and related party relationships, and provides a scope exception from consolidation guidance for certain money market funds. These provisions are effective for annual reporting periods beginning after December 15, 2015, and interim periods within those annual periods, with early adoption permitted. These provisions may also be adopted using either a full retrospective or a modified retrospective approach. Although the Company is currently assessing the impact of adopting this new accounting guidance will have on its consolidated financial statements and footnote disclosures, we expect that MEMP will become a VIE. We will either: (i) continue to consolidate MEMP and become subject to the VIE primary beneficiary disclosure requirements or (ii) no longer consolidate MEMP under the revised VIE consolidation requirements and provide disclosures that apply to variable interest holders that do not consolidate a VIE. The deconsolidation of MEMP would have a material impact on our consolidated financial statements and related disclosures.

Other accounting standards that have been issued by the FASB or other standards-setting bodies are not expected to have a material impact on the Company's financial position, results of operations and cash flows.

Note 3. Acquisitions and Divestitures

The third party acquisitions discussed below were accounted for under the acquisition method of accounting. Accordingly, we, our predecessor, and the previous owners conducted assessments of net assets acquired and recognized amounts for identifiable assets acquired and liabilities assumed at their estimated acquisition date fair values, while acquisition costs associated with the acquisitions were expensed as incurred. The operating revenues and expenses of acquired properties are included in the accompanying financial statements from their respective closing dates forward. The transactions were financed through equity offerings, capital contributions and borrowings under credit facilities.

The fair values of oil and natural gas properties are measured using valuation techniques that convert future cash flows to a single discounted amount. Significant inputs to the valuation of oil and natural properties include estimates of: (i) economic reserves; (ii) future operating and development costs; (iii) future commodity prices; and (iv) a market-based weighted average cost of capital.

MEMP has consummated several common control acquisitions since completing its initial public offering in December 2011, as further discussed in Note 13, from certain affiliates of NGP. These acquisitions were each accounted for as a transaction between entities under common control, similar to a pooling of interests, whereby the net assets acquired were recorded at historical cost.

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Acquisition-related costs

Acquisition-related costs for both related party and third party transactions are included in general and administrative expenses in the accompanying statements of operations for the periods indicated below (in thousands):

For the Year Ended December 31,		
2014	2013	2012
$6,668	$8,313	$4,538

2014 Acquisitions

On December 30, 2014, MRD acquired certain oil and natural gas producing properties from third parties in the Terryville Complex for approximately $71.9 million, including estimated customary post-closing adjustments (the “Louisiana Acquisition”).

During the fourth quarter 2014, MRD acquired incremental interests in certain oil and gas properties and leases in the Terryville Complex from third parties in four separate transactions for an aggregate purchase price of approximately $24.0 million.

On July 1, 2014, MEMP consummated a transaction to acquire certain oil and natural gas liquids properties from a third party in Wyoming for an aggregate purchase price of approximately $906.1 million, including estimated post-closing adjustments (the “Wyoming Acquisition”). Revenues of $72.0 million were recorded in the statement of operations generated earnings of approximately $22.9 million related to the Wyoming Acquisition subsequent to the closing date.

On March 25, 2014, MEMP closed a transaction to acquire certain oil and natural gas producing properties from a third party in the Eagle Ford for approximately $168.1 million (the “Eagle Ford Acquisition”). In addition, MEMP acquired a 30% interest in the seller’s Eagle Ford leasehold. During the year ended December 31, 2014, revenues of approximately $36.5 million were recorded in the statement of operations related to the Eagle Ford Acquisition subsequent to the closing date and MEMP generated earnings of approximately $16.3 million.

The following table summarizes the fair value assessment of the assets acquired and liabilities assumed as of the acquisition dates (in thousands):

	MRD Louisiana Acquisition	MEMP Eagle Ford Acquisition	MEMP Wyoming Acquisition
Oil and gas properties	$ 72,141	$ 168,606	$ 930,168
Asset retirement obligations	(271)	(285)	(3,980)
Revenue Payable	—	—	(375)
Accrued liabilities	—	(250)	(19,693)
Total identifiable net assets	$ 71,870	$ 168,071	$ 906,120

The following unaudited pro forma combined results of operations are provided for the year ended December 31, 2014 and 2013 as though the Wyoming Acquisition had been completed on January 1, 2013. The unaudited pro forma financial information was derived from the historical combined statements of operations of the Company and the previous owners and adjusted to include: (i) the revenues and direct operating expenses associated with oil and gas properties acquired, (ii) depletion expense applied to the adjusted basis of the properties acquired and (iii) interest expense on additional borrowings necessary to finance the acquisition. The unaudited pro forma financial information does not purport to be indicative of results of operations that would have occurred had the transaction occurred on the basis assumed above, nor is such information indicative of expected future results of operations.

	For the Year Ended December 31,	
	2014	2013
	(In thousands, except per share amounts)	
Revenues	$990,544	$761,443
Net income (loss)	(602,044)	257,839
Basic earnings per share	$(4.08)	$—
Diluted earnings per share	$(4.08)	$—

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2014 Divestitures

On May 9, 2014, MRD LLC sold certain producing and non-producing properties in the Mississippian oil play of Northern Oklahoma to a third party for approximately $7.6 million and recorded a loss of $3.2 million.

2013 Acquisitions

On April 30, 2013, WildHorse Resources purchased certain oil and gas properties and leases in Louisiana from a third party for approximately $67.1 million.

MEMP closed two separate transactions during 2013 to acquire certain oil and natural gas properties from third parties in East Texas (the “East Texas Acquisition”) and the Rockies (the “Rockies Acquisition”) for approximately $29.4 million in aggregate. The East Texas Acquisition closed on September 6, 2013 and the Rockies Acquisition closed on August 30, 2013.

	Louisiana Acquisition	East Texas Acquisition	Rockies Acquisition
Oil and gas properties	$ 68,887	$ 9,974	$ 20,744
Asset retirement obligation	(1,789)	(78)	(1,163)
Accrued liabilities	-	-	(118)
Total identifiable net assets	$ 67,098	$ 9,896	$ 19,463

During 2013, Propel Energy acquired incremental interests in certain oil and gas properties and leases in the Hendrick Field located in Winkler County, Texas from third parties in three separate transactions for an aggregate purchase price of approximately $9.3 million.

2013 Divestitures

On January 1, 2013, Tanos sold a natural gas gathering pipeline located in East Texas, which it had originally acquired in April 2010, to a privately held gas transportation company for a minimum purchase price of $1.5 million. The maximum allowable additional proceeds are $2.0 million. The contingent consideration is based on the natural gas pipeline servicing any new wells that Tanos drills in the area over the following three years. The contingent consideration portion of an arrangement is recorded when the consideration is determined to be realizable. Tanos recorded an aggregate gain of approximately $1.4 million related to this transaction, of which $0.4 million was contingent consideration. During 2013, Tanos also sold certain non-operated oil and gas properties for $2.9 million and recorded a gain of $1.4 million.

On May 10, 2013, Black Diamond entered into a purchase and sale agreement with a third party to sell certain of its Wyoming oil and gas properties with an estimated net book value of $39.8 million for $33.0 million, before customary adjustments. As a result, Black Diamond recorded a loss on the sale of $6.8 million. This transaction closed on June 4, 2013.

During 2013, BlueStone entered into an agreement with a third party to sell its remaining interest in certain properties in the Mossy Grove Prospect in Walker and Madison Counties located in East Texas. Total cash consideration received by BlueStone was approximately $117.9 million, which exceeded the net book value of the properties sold by $89.5 million. The transaction closed on July 31, 2013.

2012 Acquisitions

On May 1, 2012, MEMP and WildHorse jointly acquired operating and non-operating interests in certain oil and natural gas properties located in East Texas and North Louisiana from an undisclosed third party seller ("Undisclosed Seller Acquisition") for a final net purchase price of approximately $112.1 million. These properties are located primarily in Polk County, Texas and Lincoln and Claiborne Parishes, Louisiana. During the year ended December 31, 2012, approximately $22.1 million of revenue and $9.2 million of earnings were recorded in the statement of operations related to the Undisclosed Seller Acquisition subsequent to the closing date.

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On September 28, 2012, MEMP acquired certain oil and natural gas properties in East Texas from Goodrich Petroleum Corporation (“Goodrich Acquisition”) for a final net purchase price of $90.4 million after customary post-closing adjustments. The effective date of this transaction was July 1, 2012. This transaction was financed with borrowings under MEMP’s revolving credit facility. These properties are located in the East Henderson field of Rusk County, Texas. During the year ended December 31, 2012, approximately $4.6 million of revenue and $2.0 million of earnings were recorded in the statement of operations related to the Goodrich Acquisition subsequent to the closing date.