Memorial Resource Development Corp.
Form 10-K
February 24, 2016

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, 2015

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	The Nasdaq Stock Market LLC (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 þ No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No 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 þ	Accelerated filer ¨
Non-accelerated filer ¨ (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, 2015 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 $1.6 billion.

As of January 31, 2016, the registrant had 205,308,614 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 13, 2016, to be filed with the Securities and Exchange Commission within 120 days after December 31, 2015, 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.

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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;
- "Classic Pipeline" refers to Classic Pipeline & Gathering, LLC, a subsidiary of MRD Holdco that owns certain immaterial midstream assets in Texas; and
- "the previous owners" for accounting and financial reporting purposes refers to the carved-out net profits interest created from working interests in certain oil and natural gas properties that WildHorse Resources originally acquired in 2010 from third parties and immediately sold to NGP Income Co-Investment Fund II, L.P. ("NGPCIF"), a NGP controlled entity, and subsequently reacquired from NGPCIF on February 28, 2014.

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 and its consolidating subsidiaries except for MEMP and its subsidiaries.
- MEMP—reflects the combined operations of MEMP and its 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 (other than MEMP GP). 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 believe we will continue to consolidate MEMP and become subject to the VIE primary beneficiary disclosure requirements. The deconsolidation of MEMP would have a material impact on our consolidated financial statements and related disclosures in the event there is a reconsideration event that triggers deconsolidation.

Overview

We are an independent natural gas and oil company focused on the acquisition, exploration and development of natural gas and oil properties with substantially all of our activity in the Terryville Complex of North Louisiana, where we are targeting over-pressured, 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, 2015, our total leasehold position was 198,024 gross (171,570 net) acres and we had estimated proved reserves of approximately 1,378 Bcfe. As of such date, we operated approximately 100% of our proved reserves, 71% of which were natural gas. For the year ended December 31, 2015, 68% of our revenues were attributable to natural gas production, 16% to NGLs and 16% to oil.

Our average net daily production for the year ended December 31, 2015 was approximately 344.5 MMcfe/d (approximately 78% natural gas, 16% NGLs and 6% oil) and our proved reserve life was approximately 11 years. The Terryville Complex represented approximately 100% of our total net production for the year ended December 31, 2015. As of December 31, 2015, we produced from 93 horizontal wells and 468 vertical wells. During 2015, we completed and brought online 33 horizontal wells in the Terryville Complex, bringing our total number of producing horizontal wells to 85 in our primary formations as of December 31, 2015.

2015 Developments

North Louisiana Acquisition

In October 2015, we closed a transaction to acquire producing and non-producing properties in North Louisiana, including approximately 45,807 gross (45,121 net) acres for approximately $284.3 million, subject to customary post-closing adjustments, from a third party (the “North Louisiana Acquisition”). The acquisition had an effective date of August 1, 2015. We financed the North Louisiana Acquisition with the net proceeds from our September 2015 equity offering (discussed below) and borrowings under our revolving credit facility.

September 2015 Equity Offering

In September 2015, we issued 13,800,000 shares of our common stock in an underwritten public offering (which included 1,800,000 shares sold pursuant to the option to purchase additional shares of our common stock granted by us to, and exercised in full by, the underwriter). The aggregate net proceeds from our September 2015 equity offering were approximately $238.1 million after deducting underwriting discounts and commissions and offering expenses. The net proceeds from the equity offering were used to temporarily pay down our revolving credit facility and subsequently re-borrowed to fund a portion of the purchase price of the North Louisiana Acquisition that closed on October 22, 2015.

North Louisiana Acreage Option

In June 2015, we entered into an oil and gas lease option agreement with a third party pursuant to which we have the right to obtain one or more oil and gas leases. The option covers 39,769 gross (39,619 net) acres in North Louisiana and is exercisable through February 2017. The purchase price of this option was approximately $4.0 million.

Amendments to MRD Revolving Credit Facility and Borrowing Base Redeterminations

In April 2015, we entered into a fourth amendment to our revolving credit facility to, among other things, add new lenders and permit the repurchase of up to $50.0 million of our common stock. In connection therewith, the lenders under our revolving credit facility reaffirmed the borrowing base under our revolving credit facility at $725.0 million.

In September 2015, we entered into a fifth amendment to our revolving credit facility to, among other things, increase (i) the borrowing base under our revolving credit facility from $725.0 million to $1.0 billion and (ii) the aggregate elected commitment amounts to $1.0 billion. We anticipate the next borrowing base redetermination will become effective in April 2016.

Property Swap

In February 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 West Louisiana for MEMP’s North Louisiana oil and gas properties and approximately $78.4 million in cash. Terms of the transaction were approved by our Board and by its special committee, which was comprised entirely of independent directors. The transaction had an effective date of January 1, 2015.

MEMP November 2015 Beta Acquisition

In November 2015, MEMP purchased the noncontolling interest in San Pedro Bay Pipeline Company for approximately $6.0 million and completed an acquisition of the remaining interests in its oil and gas properties offshore Southern California (the “Beta Properties”) from a third party for approximately $94.6 million (the “2015 Beta Acquisition”).

MEMP first acquired its interests in the Beta properties in December 2012. The 2015 Beta Acquisition consisted of the 48.25% remaining working interests in three Pacific Outer Continental Shelf blocks in the Beta Field that are located in federal waters approximately eleven miles offshore the Port of Long Beach, California and the 48.25% remaining interest in associated facilities including (i) two combined production and drilling platforms (ii) one production processing platform, (iii) a 17.5 mile long 16-inch diameter oil pipeline and (iv) an onshore pump station, tankage and metering facility.

MEMP Semi-Annual Borrowing Base Redetermination

In November 2015, in connection with the semi-annual borrowing base redetermination by lenders under MEMP’s revolving credit facility, the borrowing base under its revolving credit facility decreased from $1.30 billion to approximately $1.18 billion. The new borrowing base became effective on November 4, 2015. The borrowing base reduction was primarily the result of the deterioration of commodity prices in the oil and natural gas industry. We anticipate the next MEMP borrowing base redetermination will become effective in April 2016.

MEMP Conversion of Subordinated Units

In February 2015, the subordination period for the 5,360,912 MEMP subordinated units ended. All of the subordinated units, which were owned by MRD Holdco, converted to common units on a one-to-one basis at the end of the subordination period and were then sold by MRD Holdco during the second quarter of 2015.

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 ("MEMP Repurchase Program"). During 2015, MEMP repurchased $52.8 million of common units, which represented a repurchase and retirement of 3,547,921 common units, under the MEMP Repurchase Program. The MEMP Repurchase Program expired in December 2015.

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 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 184,371 gross (163,228 net) acres as of December 31, 2015.

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.

As of December 31, 2015, we had 1,378 Bcfe of estimated proved reserves, substantially all of which are attributable to the Terryville Complex, and a drilling inventory consisting of 113 gross proved horizontal drilling locations to which we have attributed proved undeveloped reserves as of December 31, 2015. Since initiating our horizontal drilling program in 2011, we have drilled 85 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 89% across our acreage.

We expect our redevelopment program to continue to target four of the stacked over-pressured 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 1,800 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 proved reserves. The following table summarizes production volumes for the years ended December 31, 2015, 2014 and 2013:

	For the Year Ended December 31,		
	2015	2014	2013
Production Volumes:			
Oil (MBbls)	1,331	716	386
NGLs (MBbls)	3,249	1,763	1,118
Natural gas (MMcfe)	98,269	52,512	24,380
Total (MMcfe)	125,749	67,384	33,407
Average net production (MMcfe/d)	344.5	184.6	91.5

Other North Louisiana

We own and operate approximately 13,653 gross (8,342 net) acres as of December 31, 2015 in our Other North Louisiana region.

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, 2015, we had 1,378 Bcfe of estimated proved reserves, substantially all of which are attributable to the Terryville Complex. As of this date, our proved reserves were 71% gas and 29% 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, 2015.

Region	Proved Total (Bcfe)	% Gas	% Developed	Average Net Daily Production (MMcfe/d)
Terryville Complex	1,378	71 %	46 %	344.5

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:

Maintain a disciplined, growth oriented financial strategy. We intend to fund our growth primarily with 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 37% of our acreage in the Terryville Complex was held by production as of December 31, 2015 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.

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 9 rigs running in the Terryville Complex as of December 31, 2015, 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.

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, 2015, we owned approximately 184,371 gross (163,228 net) acres in the Terryville Complex, 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. Approximately 37% of our acreage in the Terryville Complex was held by production at December 31, 2015.

De-risked acreage position with multi-year inventory of liquids-rich drilling opportunities. As of December 31, 2015, we had a drilling inventory consisting of approximately 113 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 over-pressured 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, 2015, 68% of our revenues were attributable to natural gas, 16% to NGLs and 16% to oil.

Significant operational control with low cost operations. On a proved reserves basis, we operate approximately 100% 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 6,800 lateral feet in 2015, 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 17% from $0.24 per Mcfe for the year ended December 31, 2014 to $0.20 per Mcfe for the year ended December 31, 2015.

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 21 years of experience in the oil and natural gas industry. Jay C. Graham, our Chief Executive Officer, has 23 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 their 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.

Financial strength and flexibility. We intend to continue to fund our organic growth with 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, 2015, our total liquidity, consisting of cash on hand and available borrowing capacity under our revolving credit facility, was approximately $578.6 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 36% of our common stock. Pursuant to a voting agreement, MRD Holdco also has the right to direct the vote of an additional approximately 15% of our common stock owned by Jay Graham, our Chief Executive Officer, and certain other former management members of WildHorse Resources. The Funds also collectively indirectly own 50% of MEMP's incentive distribution rights.

Founded in 1988, Natural Gas Partners ("NGP") is a family of private equity investment funds, with approximately $16.5 billion of cumulative equity commitments, organized to make investments in the natural resources sector. NGP is part of the investment platform of NGP Energy Capital Management, a premier investment franchise in the Natural Resources industry.

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, and offshore Southern California. 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, 2015:

- MEMP's total estimated proved reserves were approximately 1,268 Bcfe, of which approximately 43% were oil and 63% were classified as proved developed reserves;
- MEMP produced from 3,357 gross (1,960 net) producing wells across its properties, with an average working interest of 58%, and MEMP or the Company is the operator of record of the properties containing 95% of MEMP's total estimated proved reserves; and
- MEMP's average net production for the three months ended December 31, 2015 was 257.3 MMcfe/d, implying a reserve-to-reserve production ratio of approximately 14 years.

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).

We anticipate receiving less than $0.1 million from our partnership interests in MEMP in 2016 assuming no changes to MEMP's outstanding common units or its last declared quarterly cash distribution of $0.10 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 GP and our other employees who perform services for MEMP or on MEMP's behalf.

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 reserves (by volume) at December 31, 2015. MEMP engaged 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, 2015. The technical persons responsible for auditing our proved 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 for overseeing the preparation of the reserves estimates and liasoning with and providing oversight of our third-party reserve engineers which audited the reserve report for our 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, 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 an M.S. in petroleum engineering.

Christa Yin is the technical person at the Company primarily responsible for overseeing the preparation of the reserves estimates and liasoning with and providing oversight of MEMP's third-party reserve engineers, which audited the internally prepared reserve report for MEMP's properties. Ms. Yin has been practicing petroleum engineering at the Company since March 2015 and has over 18 years of experience in the estimation and evaluation of reserves. From March 2014 to March 2015, she was employed by Tundra Oil and Gas, where she was responsible for analysis of acquisitions, generating development plans, and managing the reserves. From August 2011 to March 2014, she worked for HighMount Exploration & Production LLC as Manager of Acquisitions and Divestitures. From February 2005 to August 2011, Ms. Yin was employed by Tecpetrol, where she was responsible for generating development plans and managing and evaluating the reserves for the Gulf Coast region. From November 2003 to February 2005, Ms. Yin was employed by Marathon Oil Company where she was responsible for evaluating reserves and field development of various fields in Oklahoma. From June 1997 to November 2003, she held various positions which included the evaluation and estimation of reserves at Coastal Oil & Gas, which subsequently merged with El Paso Production Company in 2001. Ms. Yin is a graduate of Texas A&M University with a B.S. in petroleum engineering.

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 proved reserves presented in the NSAI reserve report was overseen by Mr. Philip S. (Scott) Frost and Mr. William J. Knights.

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.

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 an M.S. in geology.

Both 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; both 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.

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, MEMP, 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 reserve report were overseen by Timothy Wayne Smith.

Mr. Smith has been practicing consulting petroleum engineering at Ryder Scott since 2008. Before joining Ryder Scott, Mr. Smith served in a number of engineering positions with Wintershall Energy and Cities Service Oil Company. Mr. Smith is a Licensed Professional Engineer in the State of Texas with over 24 years of practical experience in the estimation and evaluation of petroleum reserves. He graduated from West Virginia University with a B.S. in petroleum engineering and from University of Phoenix with an MBA.

Mr. Smith 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.

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, 2015 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and natural gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil and natural gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into four broad categories or methods: (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.

Estimated Proved Reserves

The table below identifies our proved reserves as of December 31, 2015 per our reserve report:

	Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total (MMcfe)
Proved Developed	6,101	443,983	24,583	628,081
Proved Undeveloped	7,053	529,831	29,577	749,613
Total Proved Reserves	13,154	973,814	54,160	1,377,694

Proved Undeveloped Reserves

As of December 31, 2015, we had 750 Bcfe of proved undeveloped reserves, comprised of 7 MMBbls of oil, 530 Bcf of natural gas and 30 MMBbls of NGLs. None of our PUDs as of December 31, 2015 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 2015 were due to:

- Reclassifications of 231 Bcfe into proved developed reserves for implementation of drilling projects;
- Upward revisions of 286 Bcfe, primarily as a result of performance in the Terryville Complex.
- Downward revisions of 221 Bcfe primarily as a result of uneconomic vertical PUDs due to declines in commodity prices.

Approximately 25% (231 Bcfe) of our PUDs recorded as of December 31, 2014 were developed during the twelve months ended December 31, 2015. Total costs incurred to develop these PUDs were approximately $329.3 million, of which $74.0 million was incurred in fiscal year 2014 and $255.3 million was incurred in fiscal year 2015. We incurred $184.6 million of capital expenditures during 2015 associated with PUDs to be completed in 2016. As of December 31, 2015 per our reserve report, future development costs relating to the development of PUDs for the years 2016, 2017, 2018, and 2019 are estimated at approximately $265.3 million, $185.8 million, $240.0 million, and $62.6 million, respectively, to capture the balance of drilling the PUD reserves within a five-year timeframe. 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. 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, 2015, 2014 and 2013:

	For the Year Ending December 31,		
	2015	2014	2013
	(In thousands)		
PV-10	$932,553	$2,805,789	$1,358,861
Less: present value of future income taxes discounted at 10%	112,693	995,634	—
Standardized measure	$819,860	$1,810,155	$1,358,861

Prior to our initial public offering, we were not subject to federal income tax; hence no income taxes were applied to reserve values in 2013.

Reserves Sensitivity

Historically, commodity prices have been extremely volatile and we expect this volatility to continue for the foreseeable future. For example, for the five years ended December 31, 2015, the NYMEX-WTI oil future price ranged from a high of $113.93 per Bbl to a low of $34.73 per Bbl, while the NYMEX-Henry Hub natural gas future price ranged from a high of $6.15 per MMBtu to a low of $1.76 per MMBtu. For the year ended December 31, 2015, the West Texas Intermediate posted price ranged from a high of $61.43 per Bbl on June 10, 2015 to a low of $34.73 per Bbl on December 18, 2015 and the Henry Hub spot market price ranged from a high of $3.233 per MMBtu on January 15, 2015 to a low of $1.755 per MMBtu on December 17, 2015. NGL prices have also suffered significant recent declines. From January 1, 2016 through January 31, 2016, the West Texas Intermediate posted price dropped to a low $26.55 per Bbl on January 20, 2016 and the Henry Hub spot market price dropped to a low of $2.091 per MMBtu on January 19, 2016. 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.

While it is difficult to quantify the impact of the continuation of low commodity prices on our estimated proved reserves with any degree of certainty because of the various components and assumptions used in the process of estimating reserves, the following sensitivity table is provided to illustrate the estimated impact of pricing changes on our estimated proved reserve volumes and standardized measure. In addition to different price assumptions, the sensitivity cases below include assumed capital and operating expense changes we expect to realize under each scenario. Reductions in proved reserve volumes is attributable to reaching the economic limit sooner. The proved undeveloped reduction in volumes is a result of well locations no longer meeting our investment criteria as well as reaching the economic limit sooner. These sensitivity cases are only to demonstrate the impact that a lower price and cost environment may have on reserves volumes and standardized measure. There is no assurance that these prices or cost savings will actually be achieved.

	Actual (1)	Case A (2)	Case B (2)
Crude oil price ($/Bbl)	$46.79	$40.00	$35.00
Natural gas price ($/MMBtu)	$2.587	$2.25	$2.00
NGL price ($/Bbl)	$46.79	$40.00	$35.00
Capital expenditure reduction	n/a	10 %	15 %
Operating expenditure reduction	n/a	10 %	15 %
Proved developed reserves (MMcfe)	628,081	619,704	607,899
Proved undeveloped reserves (MMcfe)	749,613	729,234	721,256
Total proved reserves (MMcfe)	1,377,694	1,348,938	1,329,155
Proved reserve PV-10 value (in thousands)	$932,553	$703,855	$511,123
Less: present value of future income taxes discounted at 10% (in thousands)	112,693	54,776	—
Standardized measure (in thousands)	$819,860	$649,079	$511,123

(1) SEC pricing before adjustment for market differentials.
(2) Prices represent potential SEC pricing based on different pricing assumptions before adjustments for market differentials.

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, 2015, 2014 and 2013, respectively. For the year ended December 31, 2015, substantially all of our production is attributable to the Terryville Complex. For the years ending December 31, 2014 and 2013, we have presented production, revenue and price history for the Rockies region, which was divested of during 2015.

	For the Year Ended December 31, 2015 Terryville Complex
Production Volumes:	

Oil (MBbls)	1,331
NGLs (MBbls)	3,249
Natural Gas (MMcf)	98,269
Total (MMcfe)	125,749
Average net production (MMcfe/d)	344.5
Average sales price:	
Oil (per Bbl)	$ 45.78
NGL (per Bbl)	18.69
Natural Gas (Mcf)	2.57
Total (Mcfe)	$ 2.97
Average unit costs per Mcfe:	
Lease operating expense	$ 0.20

	For the Year Ended December 31, 2014		
	North Louisiana	Rockies	Total
Production Volumes:			
Oil (MBbls)	811	97	908
NGLs (MBbls)	1,833	30	1,863
Natural Gas (MMcf)	55,404	1,170	56,574
Total (MMcfe)	71,266	1,934	73,200
Average net production (MMcfe/d)	195.2	5.3	200.5
Average sales price:			
Oil (per Bbl)	$ 90.39	$ 88.27	$ 90.17
NGL (per Bbl)	42.27	32.81	42.12
Natural Gas (Mcf)	4.42	3.49	4.40
Total (Mcfe)	$ 5.74	$ 7.06	$ 5.59
Average unit costs per Mcfe:			
Lease operating expense	$ 0.23	$ 0.74	$ 0.24

	For the Year Ended December 31, 2013		
	North Louisiana	Rockies	Total
Production Volumes:			
Oil (MBbls)	606	25	631
NGLs (MBbls)	1,245	37	1,282
Natural Gas (MMcf)	28,284	445	28,729
Total (MMcfe)	39,395	817	40,212
Average net production (MMcfe/d)	107.9	2.2	110.2
Average sales price:			
Oil (per Bbl)	$101.26	$95.78	$101.05
NGL (per Bbl)	38.66	40.80	38.72
Natural Gas (Mcf)	3.71	2.91	3.69
Total (Mcfe)	$5.44	$6.39	$5.46
Average unit costs per Mcfe:			
Lease operating expense	$0.40	$1.91	$0.43

Productive Wells

The following table sets forth information regarding productive wells at December 31, 2015.

	Gross	Net	Operated
North Louisiana	561	352	414

Acreage

The following table sets forth information regarding the developed and undeveloped acreage in which we own an interest as of December 31, 2015.

	Developed Acreage		Undeveloped Acreage		Total Acreage			
	Gross	Net	Gross	Net	Gross	Net	Net HBP	Avg WI
Terryville Complex	76,279	60,394	108,092	102,834	184,371	163,228	37 %	89 %
Other North Louisiana	12,965	7,822	688	520	13,653	8,342	94 %	61 %
Total	89,244	68,216	108,780	103,354	198,024	171,570	40 %	87 %

In June 2015, we entered into an oil and gas lease option agreement with a third party pursuant to which we have the right to obtain one or more oil and gas leases. The option covers 39,769 gross (39,619 net) acres in North Louisiana and is exercisable through February 2017. The purchase price of this option was approximately $4.0 million. The table above includes 866 gross (866 net) acres associated with this option that was exercised in December 2015.

Undeveloped Acreage Expirations

The following table sets forth the gross and net undeveloped acreage in our core operating areas as of December 31, 2015 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, approximately 55%, 81% and 81% of the acreage can be retained through lease extensions in 2016, 2017 and 2018, respectively. There are no proved reserves attributable to our expiring acreage.

	2016		2017		2018	
	Gross	Net	Gross	Net	Gross	Net
Terryville Complex	6,889	6,480	10,226	9,715	78,485	74,561
Other North Louisiana	—	—	489	489	305	305
Total	6,889	6,480	10,715	10,204	78,790	74,866

Drilling Activity

The following table summarizes our drilling activity for the years ended December 31, 2015, 2014 and 2013. 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, 2015, 37 gross (33.6 net) wells were in various stages of drilling or completion.

	For the Year Ending December 31,					
	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	31.0	28.5	18.0	15.3	21.0	12.5
Dry	—	—	—	—	—	—
Total development wells	31.0	28.5	18.0	15.3	21.0	12.5
Exploratory wells:						
Productive	2.0	1.8	16.0	14.4	9.0	8.0
Dry	—	—	—	—	—	—
Total exploratory wells	2.0	1.8	16.0	14.4	9.0	8.0
Total wells drilled	33.0	30.3	34.0	29.7	30.0	20.5

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, 2015.

	Estimated Total Reserves					
	Total (Bcfe)	% Gas	% Oil & NGLs	% Developed	Standardized Measure (in millions)(1)	Average Net Daily Production (MMcfe/d)
East Texas/Louisiana	536	71 %	29 %	61 %	$ 260	156.0
Rockies	490	4 %	96 %	61 %	174	43.8
South Texas	88	66 %	34 %	88 %	63	28.3
Permian Basin	18	1 %	99 %	92 %	25	9.7
California	136	0 %	100 %	57 %	68	19.5
Total	1,268	36 %	64 %	63 %	$ 590	257.3

(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, 2015, based on MEMP's audited reserve report.

	Oil (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	Total (MMcfe)
Estimated Proved Reserves				
Total Proved Developed	50,817	311,147	30,315	797,936
Total Proved Undeveloped	40,128	150,379	13,080	469,635
Total Proved Reserves	90,945	461,526	43,395	1,267,571

Development of Proved Undeveloped Reserves

As of December 31, 2015, MEMP had 470 Bcfe of proved undeveloped reserves comprised of 40.1 MMBbls of oil, 150.4 Bcfe of natural gas and 13.1 MMBbls of NGLs. None of MEMP's PUDs as of December 31, 2015 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 2015 were due to:

- Downward performance and price revisions of 196 Bcfe;
- Reclassifications of 97 Bcfe into proved developed reserves for implementation of drilling projects;
- Acquisitions of 47 Bcfe;
- Reserve additions of 22 Bcfe; and
- Divestitures of 20 Bcfe.

Approximately 14% (97 Bcfe) of MEMP's PUDs recorded as of December 31, 2014 were developed during twelve months ended December 31, 2015. Total costs incurred to develop these PUDs were approximately $151.8 million, of which $26.8 million was incurred in fiscal year 2014 and $125.0 million was incurred in 2015. In total, MEMP incurred total capital expenditures of approximately $152.0 million during fiscal year 2015 developing PUDs, which includes $27.0 million associated with PUDs to be completed in 2016. As of December 31, 2015 per MEMP's reserve report, future development costs relating to the development of PUDs for the years 2016, 2017, 2018, and 2019 are estimated at approximately $79.8 million, $198.9 million, $194.0 million, and $195.3 million, respectively, to capture the balance of drilling the PUD reserves within a five-year timeframe. As MEMP continues to develop its properties and has more well production and completion data, MEMP believes it will continue to realize cost savings and experience lower relative drilling and completion costs as MEMP converts PUDs into proved developed reserves in the upcoming years. Based on MEMP's current expectations of MEMP's cash flows, MEMP believes that it can fund the drilling of its current PUD inventory and its expansions in the next five years from MEMP's cash flow from operations and borrowings under MEMP's revolving credit facility. For a more detailed discussion of MEMP's liquidity position, see "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources."

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, 2015, 2014 and 2013, respectively:

	For the Year Ended December 31,		
	2015	2014	2013
Production Volumes:			
Oil (MBbls)	4,087	3,135	1,797
NGLs (MBbls)	2,820	2,498	1,806
Natural Gas (MMcf)	50,875	48,721	41,287
Total (MMcfe)	92,315	82,520	62,907
Average net production (MMcfe/d)	252.9	226.0	172.3
Average sales price:			
Oil (per Bbl)	$43.48	$84.97	$96.98
NGL (per Bbl)	15.28	32.55	31.31
Natural Gas (Mcf)	2.65	4.39	3.37
Total (Mcfe)	3.85	$6.81	$5.88
Average unit costs per Mcfe:			
Lease operating expense	$1.82	$1.74	$1.50

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, 2015.

	Oil		Natural Gas	
	Gross	Net	Gross	Net
Operated (1)	474	451	1,624	1,312
Non-operated	291	28	968	169
Total	765	479	2,592	1,481

(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, 2015, substantially all of MEMP's leasehold acreage was held by production. The following table sets forth information as of December 31, 2015 relating to MEMP's leasehold acreage.

	Developed Acreage	
	Gross	Net
East Texas/ Louisiana	229,146	135,949
Rockies	140,406	72,272
South Texas	110,038	95,513
Permian Basin	23,683	22,067
Total	503,273	325,801

Undeveloped Acreage

The following table sets forth information as of December 31, 2015 relating to MEMP's undeveloped leasehold acreage.

	Undeveloped Acreage	
	Gross	Net
East Texas/Louisiana	31,584	17,638
Rockies	86,263	50,616
South Texas	6,443	6,443
Permian Basin	6,776	5,268
Total	131,066	79,965

Drilling Activities

MEMP's drilling activities primarily consist 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, 2015, 6.0 gross (6.0 net) wells were in various stages of completion.

	For the Year Ending December 31,					
	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	43.0	20.0	106.0	60.8	46.0	33.4
Dry	—	—	7.0	1.9	—	—
Exploratory wells:						
Productive	—	—	—	—	—	—
Dry	1.0	1.0	—	—	—	—
Total wells:						
Productive	43.0	20.0	106.0	60.8	46.0	33.4
Dry	1.0	1.0	7.0	1.9	—	—
Total	44.0	21.0	113.0	62.7	46.0	33.4

For purposes of the table above, MEMP's previous owners refers collectively to (a) certain oil and natural gas properties acquired from WHT Energy Partners ("WHT") in March 2013; (b) 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; and (c) certain oil and natural gas properties acquired through the Property Swap.

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, except for one contract that requires them to deliver 35,000 MMbtu/d through March 2016.

MEMP has also entered into a gas gathering agreement associated with a certain portion of its East Texas production with a third party midstream service provider that has volumetric requirements. Information regarding MEMP's delivery commitments under this contract is contained in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations — Contractual Obligations" and Note 16 under "Item 8. Financial Statements and Supplementary Data," both contained herein.

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, 2015, Energy Transfer Equity, L.P. and subsidiaries and Plains Marketing, L.P. accounted for 56% and 11% of our revenues, respectively, while Sinclair Oil & Gas Company, Royal Dutch Shell plc and affiliates, and Phillips 66 accounted for 18%, 14% 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 30%, resulting in a net revenue interest to us generally ranging from 87.5% to 70%.

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 57% of our total estimated proved reserves as of December 31, 2015 and approximately 38% of MEMP's total estimated proved reserves as of December 31, 2015, 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, that 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, seismically active areas, 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. Liability under such laws and regulations is strict (i.e., no showing of "fault" is required) and can be joint and several. 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 common law-based 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, but 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 stringent requirements on the generation, storage, treatment, transportation and disposal of hazardous wastes. Certain petroleum production wastes are excluded from RCRA's hazardous waste regulations. These wastes, instead, are regulated under RCRA's less stringent solid waste provisions, state laws or other federal laws. It is also possible, 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, 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. The EPA plans to develop a Notice of Proposed Rulemaking by December 2016, which would describe a proposed mechanism – regulatory, voluntary, or a combination of both – to collect data on hydraulic fracturing chemical substances and mixtures. Also, on April 7, 2015, the EPA published a proposed rule establishing federal pre-treatment standards for wastewater discharged from onshore unconventional oil and gas extraction facilities to publicly owned treatment works ("POTW"). The EPA asserts that wastewater from such facilities can be generated in large quantities and can contain constituents that may disrupt POTW operations and/or be discharged, untreated, from the POTW to receiving waters. If adopted, the new pre-treatment rule would require unconventional oil and gas facilities to pre-treat wastewater before transferring it to a POTW. The public comment period ended on July 17, 2015, and the EPA is expected to publish a final rule by August 2016. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and gas extraction wastewater. The EPA is collecting data and information related to the extent to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities, and the environmental impacts of discharges from CWT facilities

Further, on August 16, 2012, the EPA published 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 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. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of the requests for reconsideration. For example, in September 2013 and December 2014, the EPA amended its rules to extend compliance deadlines and to clarify the NSPS. In addition, September 18, 2015, the EPA published a suite of proposed rules to reduce methane and VOC emissions from oil and gas industry, including new "downstream" requirements covering equipment in the natural gas transmission segment of the industry that was not regulated by the 2012 rules. The public comment period closed on December 4, 2015. 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, on March 26, 2015, the Bureau of Land Management ("BLM") published a final rule governing hydraulic fracturing on federal and Indian lands. The rule requires public disclosure of chemicals used in hydraulic fracturing, implementation of a casing and cementing program, management of recovered fluids, and submission to the BLM of detailed information about the proposed operation, including wellbore geology, the location of faults and fractures, and the depths of all usable water. The rule took effect on June 24, 2015, although it is the subject of several pending lawsuits filed by industry groups and at least four states, alleging that federal law does not give the BLM authority to regulate hydraulic fracturing. On September 30, 2015, the United States District Court for Wyoming issued a preliminary injunction preventing the BLM from implementing the rule nationwide. This order has been appealed to the Tenth Circuit Court of Appeals. Also, on January 22, 2016, the BLM announced a proposed rule to reduce the flaring, venting and leaking of methane from oil and gas operations on federal and Indian lands. The proposed rule would require operators to use currently available technologies and equipment to reduce flaring, periodically inspect their operations for leaks, and replace outdated equipment that vents large quantities of gas into the air. The rule would also clarify when operators owe the government royalties for flared gas.

Several states have also 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 Railroad Commission of Texas ("Commission") and the public the chemicals used in the hydraulic fracturing process, as well as the total volume of water used. Also, in May 2013, the 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. Additionally, on October 28, 2014, the 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, which became effective on November 17, 2014, 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 Commission has used this authority to deny permits for waste disposal wells. 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 EPA is currently evaluating the potential impacts of hydraulic fracturing on drinking water resources. In June 2015, the EPA released its draft assessment report for peer review and public comment, finding that, while there are certain mechanisms by which hydraulic fracturing activities could potentially impact drinking water resources, there is no evidence available showing that those mechanisms have led to widespread, systemic impacts. Also, on February 6, 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and minimizing the potential for significant injection-induced seismic events. Other governmental agencies, including the U.S. Department of Energy, the U.S. Geological Survey, and the U.S. Government Accountability Office, 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 induced seismic activity and 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. For example, the U.S. 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. 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, on August 16, 2012, the EPA published final regulations under the CAA that establish new emission controls for oil and natural gas production and processing operations, which regulations are discussed in more detail above under the caption “Hydraulic Fracturing.”

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. On December 19, 2014, the EPA issued two memoranda providing initial guidance on GHG permitting requirements in response to the Court’s decision. In its preliminary guidance, the EPA indicated that it would promulgate a rule to rescind any PSD permits issued under the portions of the tailoring rule that were vacated by the Court. In the interim, the EPA issued a narrowly crafted “no action assurance” indicating it will exercise its enforcement discretion not to pursue enforcement of the terms and conditions relating to GHGs in an EPA-issued PSD permit, and for related terms and conditions in a Title V permit. On April 30, 2015, the EPA issued a final rule allowing permitting authorities to rescind PSD permits issued under the invalid regulations.

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 October 2015, the EPA amended the GHG reporting rule to add the reporting of GHG emissions from gathering and boosting systems, completions and workovers of oil wells using hydraulic fracturing, and blowdowns of natural gas transmission pipelines. 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.

In addition, the EPA has continued to adopt GHG regulations applicable to other industries, such as its August 2015 adoption of three separate, but related, actions to address carbon dioxide pollution from power plants, including final Carbon Pollution Standards for new, modified and reconstructed power plants, a final Clean Power Plan to cut carbon dioxide pollution from existing power plants, and a proposed federal plan to implement the Clean Power Plan emission guidelines. Upon publication of the Clean Power Plan on October 23, 2015, more than two dozen States as well as industry and labor groups challenged the Clean Power Plan in the D.C. Circuit Court of Appeals. As a result of this continued regulatory focus, future GHG regulations of the oil and gas industry remain a possibility.

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, almost one-half of the states have taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. 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.

In December 2015, the United States joined the international community at the 21st Conference of the Parties (COP-21) of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris

Agreement calls for the parties to undertake “ambitious efforts” to limit the average global temperature, and to conserve and enhance sinks and reservoirs of GHGs. The Agreement, if ratified, establishes a framework for the parties to cooperate and report actions to reduce GHG emissions.

Restrictions on GHG emissions that may be imposed 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.

In addition, claims have been made against certain energy companies alleging that GHG emissions from oil and natural gas operations constitute a public nuisance under federal and/or state common law. As a result, private individuals may seek to enforce environmental laws and regulations against us and could allege personal injury or property damages. While our business is not a party to this litigation, we could be named in actions making similar allegations. An unfavorable ruling in any such case could adversely impact our business, financial condition and results of operations.

Finally, 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 at least three lawsuits. On September 1, 2015, the U.S. District Court for the Western District of Texas overturned the listing of the lesser prairie chicken, holding that the FWS's decision had been arbitrary and capricious and not consistent with its own policies. The FWS has requested that the Court amend its judgment to allow the agency to substantiate or reconsider its action. 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 2015, 2014 and 2013.

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, 2015, 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, with an additional annual aggregate retention of $1.0 million. Specific to offshore operations, the energy package policy also includes loss of production income coverage insuring us against a loss up to $48.6 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, 2015, 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 certain service providers, including 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 or during service 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, 2015, we had 484 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. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. 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, 2015, the NYMEX-WTI oil future price ranged from a high of $113.93 per Bbl to a low of $34.73 per Bbl, while the NYMEX-Henry Hub natural gas future price ranged from a high of $6.149 per MMBtu to a low of $1.755 per MMBtu. Recently, oil and natural gas prices have declined significantly. Through December 31, 2015, the West Texas Intermediate posted price had declined from a high of $61.43 per Bbl on June 10, 2015 to $37.04 per Bbl on December 31, 2015. In addition, the Henry Hub spot market price had declined from a high of $3.23 per MMBtu on January 14, 2015 to $2.34 per MMBtu on December 31, 2015. From January 1, 2016 through January 31, 2016, the West Texas Intermediate posted price dropped to a low of $26.55 per Bbl on January 20, 2016 and the Henry Hub spot market price dropped to a low of $2.091 per MMBtu on January 19, 2016. Any further substantial decline in commodity prices will likely have a material adverse effect on our business, results of operations and financial condition, as well as on our level of expenditures for the development of our reserves.

NGLs comprised 24% of our estimated proved reserves and accounted for 16% of our production on a volume equivalent basis for the year ended December 31, 2015. NGL prices have also decreased recently, principally due to significant excess 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.

While the current borrowing base under our revolving credit facility is $1 billion, our borrowing base is subject to re-determination on a semi-annual basis. Our borrowing base is based in substantial part on the value of our oil and natural gas reserves which are, in turn, impacted by prevailing oil and natural gas prices. Accordingly, declining oil and natural gas prices may have an impact on the amount we can borrow under our revolving credit facility, which could affect our cash flows and ability to execute on our business plans. The next semi-annual redetermination is scheduled for April 2016, and we may have a decrease in our borrowing base if oil and natural gas prices continue to decline. If our borrowing base declines significantly, we would have to either raise additional capital or adjust our drilling plan.

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.

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.

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 of the initial lease date, 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, 2015, we had 6,889 gross (6,480 net) acres scheduled to expire in 2016, 10,715 gross (10,204 net) acres scheduled to expire in 2017, and 78,790 gross (74,866 net) acres scheduled to expire in 2018. 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. We cannot assure you that we will have the liquidity to deploy 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, 2015, 37 gross (33.6 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.

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 54% of our total proved reserves at December 31, 2015 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, that the results of such development will be as estimated, or that future commodity prices will justify that development. 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.

Our industry is cyclical, and historically there have been periodic shortages of rigs, equipment, supplies and crew. Sustained declines in oil and natural gas prices may reduce the number of service providers for such rigs, equipment, supplies and crews, contributing to or resulting in shortages. Alternatively, during periods of higher oil and natural gas prices, 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.

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

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.

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. For more information, see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk".

We are exposed to trade credit risk in the ordinary course of our business activities.

We are exposed to risks of loss in the event of nonperformance by our vendors and other counterparties. Some of our vendors and other counterparties may be highly leveraged and subject to their own operating and regulatory risks. Many of our vendors and other counterparties finance their activities through cash flow from operations, the incurrence of debt or the issuances of equity. The combination of reduction of cash flow resulting from declines in commodity prices and the lack of availability of debt or equity financing may result in a significant reduction in our vendors' and other counterparties' liquidity and ability to make payments or perform on their obligations to us. Even if our credit review and analysis mechanisms work properly, we may experience financial losses in our dealings with other parties. Any increase in the nonpayment or nonperformance by our vendors and/or counterparties could adversely affect our business, financial condition, results of operations and cash flows.

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 will likely continue to limit our ability to book additional PUDs as we pursue our drilling program, especially in a time of depressed commodity prices. 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 as of December 31, 2015 may be higher than 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 as of December 31, 2015, 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, 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. Our estimated proved reserves as of December 31, 2015 and related PV-10 and Standardized Measure were calculated under SEC rules using twelve-month trailing average benchmark prices of $46.79 per barrel of oil (WTI) and $2.59 per MMBtu (Henry Hub spot). 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. On February 1, 2016, the prompt month NYMEX-WTI futures price for crude oil was $31.62 per Bbl and the prompt month NYMEX-Henry Hub futures price of natural gas was $2.152 per MMBtu. 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. Using more recent prices in estimating our proved reserves, without giving effect to any acquisitions or development activities we have executed during 2016, would likely result in a reduction in proved reserve volumes due to economic limits, which would reduce the PV-10 and standardized measure of our proved reserves. See “Item 1. Business—Reserve Sensitivity”.

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, 2015, all of our total estimated proved reserves and for the year ended December 31, 2015, all 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 and the availability and cost of credit 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.

We are required to pay fees to our midstream service providers based on minimum volumes regardless of actual volume throughput.

We have contracts with midstream service providers for gathering, processing and transportation services with minimum volume delivery commitments. We are obligated to pay fees on minimum volumes to midstream service providers regardless of actual volume throughput, which fees could be significant and have a material adverse effect on our results of operations. For more information, see Note 13 and 16 of the Notes to Consolidated and Combined Financial Statements included under “Item 8. Financial Statements and Supplementary Data” as well as “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations —Contractual Obligations”.

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, seismically active areas, 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.

In December 2009, the EPA published its findings that emissions of greenhouse gases ("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. On December 19, 2014, the EPA issued two memoranda providing initial guidance on GHG permitting requirements in response to the Court's decision. In its preliminary guidance, the EPA indicated that it would promulgate a rule to rescind any PSD permits issued under the portions of the tailoring rule that were vacated by the Court. In the interim, the EPA issued a narrowly crafted "no action assurance" indicating it will exercise its enforcement discretion not to pursue enforcement of the terms and conditions relating to GHGs in an EPA-issued PSD permit, and for related terms and conditions in a Title V permit. On April 30, 2015, the EPA issued a final rule allowing permitting authorities to rescind PSD permits issued under the invalid regulations.

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. In addition, the EPA has continued to adopt GHG regulations applicable to other industries, such as its August 2015 adoption of three separate, but related, actions to address carbon dioxide pollution from power plants. 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, almost one-half of the states have taken legal measures to reduce emissions of greenhouse gases primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. 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.

In December 2015, the United States joined the international community at the 21st Conference of the Parties (COP-21) of the United Nations Framework Convention on Climate Change in Paris, France. The resulting Paris Agreement calls for the parties to undertake "ambitious efforts" to limit the average global temperature, and to conserve and enhance sinks and reservoirs of GHGs. The Paris Agreement, if ratified, establishes a framework for the parties to cooperate and report actions to reduce GHG emissions.

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations 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 at least three lawsuit. On September 1, 2015, the U.S. District Court for the Western District of Texas overturned the listing of the lesser prairie chicken, holding that the FWS's decision had been arbitrary and capricious and not consistent with its own policies. The FWS has requested that the Court amend its judgment to allow the agency to substantiate or reconsider its action. 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, the SEC, and federal regulators of financial institutions, or the Prudential Regulators, 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, the SEC and the Prudential Regulators have issued a large number of rules to implement the Dodd-Frank Act, including a rule which we refer to as the “Clearing Rule,” requiring clearing of hedges, or swaps, that are subject to it (currently, only certain interest rate and credit default swaps, which we do not presently have), a rule establishing an “end user” exception to the Clearing Rule, referred to herein as the “End User Exception,” a rule, which we refer to as the “Margin Rule,” setting forth collateral requirements in connection with swaps that are not cleared and also an exception to the Margin Rule for end users that are not financial end users, which exception we refer to as the “Non-Financial End User Exception,” and a rule, subsequently vacated by the United States District Court for the District of Columbia and remanded to the CFTC for further proceedings, imposing position limits. The CFTC has proposed a new version of this rule, which we refer to as the “Re-Proposed Position Limit Rule,” with respect to which the comment period has closed but a final rule has not been issued.

We qualify as a for End User Exception will utilize it if the Clearing Rule is expanded to cover swaps in which we participate, we qualify for the Non-Financial End User Exception and will not be required to post margin under the Margin Rule and the quantities under the swaps in which we participate are well within applicable limits under the Re-Proposed Position Limit Rule, so we do not expect to be directly affected by such rules. 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 will be required to post margin in connection with their hedging activities with other swap dealers, major swap participants, financial end users and other persons that do not qualify for the Non-Financial End User Exception. In addition, the European Union and other non-U.S. jurisdictions have enacted laws and regulations, which we refer to collectively as "Foreign Regulations" which may apply to our transactions with counterparties subject to such Foreign Regulations. The Dodd-Frank Act, the rules which have been adopted and not vacated, and, to the extent that the Re-Proposed Position Limit Rule is ultimately effected, such proposed rules could significantly increase the cost of derivative contracts, 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. The Foreign Regulations could have similar effects. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations and Foreign 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, 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. The EPA plans to develop a Notice of Proposed Rulemaking by December 2016, which would describe a proposed mechanism – regulatory, voluntary, or a combination of both – to collect data on hydraulic fracturing chemical substances and mixtures.

Hydraulic fracturing stimulation requires the use of a significant volume of water with some resulting "flowback," as well as "produced water." On April 7, 2015, the EPA published a proposed rule establishing federal pre-treatment standards for wastewater discharged from onshore unconventional oil and gas extraction facilities to publicly owned treatment works ("POTW"). The EPA asserts that wastewater from such facilities can be generated in large quantities and can contain constituents that may disrupt POTW operations and/or be discharged, untreated, from the POTW to receiving waters. If adopted, the new pre-treatment rule would require unconventional oil and gas facilities to pre-treat wastewater before transferring it to a POTW. The public comment period ended on July 17, 2015, and the EPA is expected to publish a final rule by August 2016. The EPA is also conducting a study of private wastewater treatment facilities (also known as centralized waste treatment, or CWT, facilities) accepting oil and gas extraction wastewater. The EPA is collecting data and information related to the extent to which CWT facilities accept such wastewater, available treatment technologies (and their associated costs), discharge characteristics, financial characteristics of CWT facilities, and the environmental impacts of discharges from CWT facilities.

In August 2012, the EPA published final 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 EPA received numerous requests for reconsideration of these rules from both industry and the environmental community. In response, the EPA has issued, and will likely continue to issue, revised rules responsive to some of these requests for reconsideration. For example, in September 2013 and December 2014, the EPA amended its rules to extend compliance deadlines and to clarify the NSPS. In addition, on September 18, 2015, the EPA published a suite of proposed rules to reduce methane and VOC emissions from oil and gas industry, including new "downstream" requirements covering equipment in the natural gas transmission segment of the industry that was not regulated by the 2012 rules. The public comment period closed on December 4, 2015. 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, on March 26, 2015, the federal Bureau of Land Management ("BLM") published a final rule governing hydraulic fracturing on federal and Indian lands. The rule requires public disclosure of chemicals used in hydraulic fracturing implementation of a casing and cementing program, management of recovered fluids, and submission to the BLM of detailed information about the proposed operation, including wellbore geology, the location of faults and fractures, and the depths of all usable water. This rule took effect on June 24, 2015, although it is the subject of several pending lawsuits filed by industry groups and at least four states, alleging that federal law does not give the BLM authority to regulate hydraulic fracturing. On September 30, 2015, the United States District Court for Wyoming issued a preliminary injunction preventing the BLM from implementing the rule nationwide. This order has been appealed to the Tenth Circuit Court of Appeals. Also, on January 22, 2016, the BLM announced a proposed rule to reduce the flaring, venting and leaking of methane from oil and gas operations on federal and Indian lands. The proposed rule would require operators to use currently available technologies and equipment to reduce flaring, periodically inspect their operations for leaks, and replace outdated equipment that vents large quantities of gas into the air. The rule would also clarify when operators owe the government royalties for flared gas.

Certain states, which we operate, 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, Texas requires oil and natural gas operators to disclose to the Texas Railroad Commission of Texas and the public the chemicals used in the hydraulic fracturing process, as well as the total volume of water used. Furthermore, in May 2013, the Commission adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources. Additionally, 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, which became effective on November 17, 2014, 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 Commission has used this authority to deny permits for waste disposal wells. 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. The U.S. 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. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

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 EPA is currently evaluating the potential impacts of hydraulic fracturing on drinking water resources. In June 2015, the EPA released its draft assessment report for peer review and public comment, finding that, while there are certain mechanisms by which hydraulic fracturing activities could potentially impact drinking water resources, there is no evidence available showing that those mechanisms have led to widespread, systemic impacts. Also, on February 6, 2015, the EPA released a report with findings and recommendations related to public concern about induced seismic activity from disposal wells. The report recommends strategies for managing and minimizing the potential for significant injection-induced seismic events. Other governmental agencies, including the U.S. Department of Energy, the U.S. Geological Survey, and the U.S. Government Accountability Office, 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.

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.

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, seismically active areas, 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.

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, 2015, we had aggregate indebtedness of approximately $1.0 billion 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 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 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 36% of the combined voting power of our common stock. MRD Holdco, Mr. Graham, our Chief Executive Officer, and certain other former management members of WildHorse Resources, who own in the aggregate approximately 15% of the combined voting power of our common stock, are party to a voting agreement, pursuant to which Mr. Graham, our Chief Executive Officer, and certain other former management members of

WildHorse Resources agreed, 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 in the near term. 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.

Some 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. Graham, our Chief Executive Officer and one of our directors, was a former Co-CEO of WildHorse Resources II, LLC, an affiliate, and continues to hold ownership interests in certain NGP 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 remain 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, Mr. Graham, our Chief Executive Officer, and certain other 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, including Mr. Graham, our Chief Executive Officer, are party to the Registration Rights Agreement, which required us to effect the registration of their shares. On July 8, 2015, we filed a registration statement with the SEC on Form S-3 registering all of the registrable shares. 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. 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 our independent registered 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.

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, 2015.

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 January 31, 2016, we had approximately 205,308,614 shares of common stock outstanding and 4 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
2015		
4th Quarter	$20.14	$13.37
3rd Quarter	$20.55	$14.61
2nd Quarter	$20.98	$16.92
1st Quarter	$21.57	$15.87
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

Since our initial public offering, we have not declared any dividends and 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, 2015:

Plan Category	Number of securities to be issued upon exercise of outstanding options,	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity

	warrants and rights		compensation plans
Equity compensation plans not approved by security holders (1):			
Long-Term Incentive Plan	—	—	17,367,573

(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

During the three months ended December 31, 2015, there was no repurchases of our common shares.

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.

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, 2015. 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	December 31, 2014	December 31, 2015
MRD	$100.00	$ 94.89	$ 85.00
S&P 500 Index	$100.00	$ 107.83	$ 109.33
S&P Oil and Gas E&P Select Index	$100.00	$ 60.47	$ 38.67

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, 2015, 2014, 2013 and 2012 presented below have been derived from our consolidated financial statements and those of 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 initial 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;
- an acquisition by MEMP of certain oil and natural gas producing properties in the Eagle Ford 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 June 2014 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;
- an acquisition by MEMP of certain oil and natural gas liquid properties in Wyoming in July 2014 for a purchase price of approximately $906.1 million; and
- an acquisition by MEMP for the remaining interest in the Beta properties from a third party in November 2015 for approximately $94.6 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,			
	2015	2014	2013	2012
	(In thousands, except per share data)			
Statement of Operations Data:				
Revenues:				
Oil & natural gas sales	$729,464	$970,747	$610,992	$408,911
Other revenues	2,725	4,378	3,075	3,237
Total revenues	732,189	975,125	614,067	412,148
Costs and expenses:				
Lease operating	193,102	161,303	111,798	101,795
Gathering, processing, and transportation	107,493	77,848	42,721	19,353
Gathering, processing, and transportation - affiliate	25,403	—	—	—
Exploration	11,286	16,603	2,356	9,800
Taxes other than income	40,724	45,751	27,146	23,624
Depreciation, depletion, and amortization	384,556	314,193	184,717	138,672
Impairment of proved oil and natural gas properties	616,784	432,116	6,600	28,871
Incentive unit compensation expense	35,142	943,949	43,279	9,510
General and administrative	102,959	87,673	82,079	59,677
Accretion of asset retirement obligations	7,542	6,306	5,581	5,009
(Gain) loss on commodity derivative instruments	(744,139)	(749,988)	(29,294)	(34,905)
(Gain) loss on sale of properties	(3,045)	3,057	(85,621)	(9,761)
Other, net	(665)	(12)	649	502
Total costs and expenses	777,142	1,338,799	392,011	352,147
Operating income (loss)	(44,953)	(363,674)	222,056	60,001
Other income (expense):				
Interest expense, net	(154,128)	(133,833)	(69,250)	(33,238)
Loss on extinguishment of debt	—	(37,248)	—	—
Amortization of investment premium	—	—	—	(194)
Other, net	(979)	(337)	145	535
Total other income (expense)	(155,107)	(171,418)	(69,105)	(32,897)
Income (loss) before income taxes	(200,060)	(535,092)	152,951	27,104
Income tax benefit (expense)	(97,830)	(100,971)	(1,619)	(107)
Net income (loss)	(297,890)	(636,063)	151,332	26,997
Net income (loss) attributable to noncontrolling interest	(393,538)	126,788	49,830	(2,701)
Net income (loss) attributable to Memorial Resource Development Corp.	95,648	(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) allocated to participating restricted stockholders	(734)	—	—	—
Net income (loss) available to common stockholders	$94,914	$(784,581)	$—	$—
Earnings per common share:				
Basic	$0.49	$(4.08)	$—	$—
Diluted	$0.49	$(4.08)	$—	$—

Cash Flow Data:				
Net cash flow provided by operating activities	$633,911	$476,271	$277,823	$240,404
Net cash used in investing activities	(1,260,289)	(1,816,979)	(367,443)	(606,738)
Net cash provided by financing activities	622,595	1,268,945	117,950	361,761
Balance Sheet Data:				
Working capital	$450,950	$266,685	$44,909	$63,189
Total assets	5,082,849	4,559,826	2,796,817	2,459,304
Total debt	3,012,643	2,344,692	1,630,873	939,382
Total equity	1,467,921	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 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, Jay Graham, our Chief Executive Officer, and certain other 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. We are currently majority-owned by the group consisting of MRD Holdco, Mr. Graham, our Chief Executive Officer, and certain other 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 and its consolidating subsidiaries except for MEMP and its subsidiaries.
- MEMP—reflects the combined operations of MEMP and its subsidiaries.

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

- acquisition by MEMP of certain oil and gas properties in East Texas and West Louisiana from MRD in exchange for MEMP's North Louisiana oil and gas properties and approximately $78.4 million in cash in February 2015;
- 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; and
- 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.

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, also 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, all of which were retained by MRD Holdco after our initial public offering.

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 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 as market conditions dictate.

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Outlook

Our financial position and future prospects, including our revenues, operating results, profitability, liquidity, future growth and the value of our assets, depend primarily on prevailing commodity prices. Starting in 2014, throughout 2015 and continuing into 2016, commodity prices dropped significantly, with the West Texas Intermediate posted price declining from $107 per Bbl in June 2014 to less than $30 per Bbl in January 2016 and the Henry Hub spot market price declining from $6 per MMBtu in February 2014 to less than $3 per MMBtu in January 2016. NGL prices have also suffered significant declines. A combination of oversupply from production growth and weaker demand due to weak economic activity and increased efficiency has contributed to the falling prices.

As a result of the significant decline in commodity prices and general uncertainty regarding the timing and nature of the recovery of prices in the future, we expect 2016 to be challenging and our strategic focus will be on reducing our operating costs and seeking to preserve as much of our liquidity and financial flexibility as possible in this lower commodity price environment.

The U.S. Energy Information Administration, or EIA, forecasts that Brent crude oil prices will average $38 per Bbl in 2016 and $50 per Bbl in 2017. North Sea Brent crude oil spot prices averaged $31 per Bbl in January 2016, the lowest monthly average Brent price since December 2003, down $7 per Bbl from the December 2015 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 2016, keeping downward pressure on oil prices. Like Brent crude oil prices, WTI prices have decreased considerably, with monthly average prices falling by more than 37% as of December 2015 after reaching their 2015 peak of $59.83 per Bbl in June. The EIA expects WTI crude oil prices to average $2 per Bbl lower than Brent in 2016 and $3 per Bbl lower in 2017.

The EIA expects that natural gas inventories will end the winter heating season in 2016 at 20% above the level at the same time last year. The EIA expects the Henry Hub natural gas spot price to average $2.64 per MMBtu in 2016 and $3.22 per MMBtu in 2017, compared with $2.63 per MMBtu in 2015. The EIA expects monthly average spot prices to remain less than $3 per MMBtu until 2017.

In January 2016, we established a full year 2016 capital expenditure budget that was approximately 30% lower than our 2015 capital expenditure budget. We expect our 2016 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 spend 50% of our capital budget in the first quarter of 2016. We expect to fund our 2016 development 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. We believe we have built significant flexibility into our 2016 capital budget, not only in the timing of completions, but also in our operated rig count. We will have the option to increase or decrease our capital activity as commodity prices dictate, which will allow us to preserve liquidity while maintaining flexibility in our completions schedule.

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.

For a discussion of the potential impact of commodity price changes on our estimated proved reserves, including quantification of such potential impact, please read "Item 1. Business – Our Oil and Natural Gas Data – Reserves Sensitivity."

Commodity prices have historically been volatile, and we expect this volatility to continue for the foreseeable future. We will continue to monitor our liquidity, including opportunities for liquidity enhancement through possible joint-venture arrangements, coordinate our capital expenditure program with our expected cash flows and projected debt-repayment schedule, and evaluate available funding and other strategic alternatives in light of the current and expected commodity price environment and market conditions.

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.

Gathering, processing and transportation. These are costs incurred to deliver production of our natural gas, NGLs and oil to the market. Cost levels of these expenses can vary based on the volume of natural gas, NGLs and oil produced as well as the cost of commodity processing.

Taxes other than income. These consist of severance, ad valorem taxes, and franchise 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.

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, 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. We are a corporation subject to federal and certain state income taxes. MEMP, which is consolidated with us for financial reporting purposes, is organized as a pass-through entity for federal and most state income tax purposes, with the exception of the state of Texas. As a result, MEMP’s partners are responsible for federal and state income taxes on their share of taxable income. Certain of MEMP’s consolidated subsidiaries are taxed as corporations for federal and state income tax purposes. 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 and state income taxes.

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.

Unproved oil and natural gas properties are reviewed for impairment based on time or geologic factors. Information such as drilling results, reservoir performance, seismic interpretation or future plans to develop acreage is also considered. When unproved property investments are deemed to be impaired, the expense is reported in exploration expenses.

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 was 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 were forfeited if an employee was no longer employed. All incentive units would be forfeited if a holder resigned whether the incentive units were vested or not. If the payouts had not yet occurred, then all incentive units, whether or not vested, would be forfeited automatically (unless extended).

In connection with the closing of our initial public offering, Mr. Graham, our Chief Executive Officer, and certain other 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 recognized by us related to the incentive units will be offset by a deemed capital contribution 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 and Other Financial 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.

Embedded derivatives that are required to be bifurcated and accounted for separately are treated in the same manner as freestanding derivatives. Embedded derivatives are recorded at fair value, with the difference between the basis of the hybrid financial instrument and the fair value of the embedded derivative recorded as the carrying value of the host contract. See Note 5 of the Notes to Consolidated and Combined Financial Statements under "Item 8. Financial and Supplementary Data," contained herein for further information on certain commodity contracts that required bifurcation.

Income Tax

We are a corporation subject to federal and certain state income taxes. 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 use the asset and liability method of accounting for income taxes, under which deferred tax assets and liabilities are recognized for the future tax consequences of (1) temporary differences between the tax basis in assets and liabilities and their reported amounts in the financial statements and (2) operating loss and tax credit carryforwards.

Deferred income tax assets and liabilities are based on enacted tax rates applicable to the future period when those 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 deferred tax assets will not be realized. We recognize interest and penalties accrued to unrecognized tax benefits in other income (expense) in our consolidated statement of operations.

We recognize a tax benefit from an uncertain tax position 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 effective settlement with a taxing authority.

Results of Operations

MRD Segment

The MRD Segment's results of operations for the years ended December 31, 2015, 2014, and 2013 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 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; 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 owned certain immaterial leasehold interests and overriding royalty interests in Texas and Montana, MRD Midstream LLC, which owned 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 for comparability purposes, which includes the following transactions:

- acquisition by MEMP of certain assets from the MRD Segment in East Texas in exchange for approximately $78.4 million in cash and certain properties in North Louisiana in February 2015;
- 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; and
- acquisition by MEMP of all the outstanding membership interests in WHT for a purchase price of approximately $200.0 million in March 2013.

	For the Year Ended December 31,		
	2015	2014	2013
	(in thousands)		
Oil & natural gas sales	$374,042	$409,070	$219,552
Lease operating	24,903	17,570	17,315
Gathering, processing, and transportation (including affiliate)	97,957	45,956	17,666
Exploration	8,969	13,853	1,034
Taxes other than income	14,896	12,610	8,699
Depreciation, depletion, and amortization	188,742	128,238	70,903
Impairment expense	—	24,576	2,528
Incentive unit compensation expense	35,142	943,949	34,997
General and administrative	46,288	38,549	35,309
(Gain) loss on commodity derivative instruments	(281,249)	(257,734)	(3,161)
(Gain) loss on sale of properties	(47)	3,057	(82,773)
Interest expense, net	(39,396)	(50,283)	(24,948)
Loss on extinguishment of debt	—	(37,248)	—
Income tax benefit (expense)	(100,005)	(102,392)	(1,311)
Net income (loss)	97,274	(764,333)	91,390
Natural gas and oil revenue:			
Oil sales	$60,931	$81,871	$63,761
NGL sales	60,718	78,470	49,641
Natural gas sales	252,393	248,729	106,150
Total natural gas and oil revenue	$374,042	$409,070	$219,552
Production Volumes:			
Oil (MBbls)	1,331	908	631
NGLs (MBbls)	3,249	1,863	1,282
Natural gas (MMcf)	98,269	56,574	28,729
Total (MMcfe)	125,749	73,200	40,212
Average net production (MMcfe/d)	344.5	200.5	110.2
Average sales price:			
Oil (per Bbl)	$45.78	$90.17	$101.05
NGL (per Bbl)	18.69	42.12	38.72
Natural gas (per Mcf)	2.57	4.40	3.69
Total (Mcfe)	$2.97	$5.59	$5.46
Average unit costs per Mcfe:			
Lease operating expense	$0.20	$0.24	$0.43
Gathering, processing, and transportation (including affiliate)	0.78	0.63	0.44
Taxes other than income	0.12	0.17	0.22
General and administrative expenses	0.37	0.53	0.88
Depletion, depreciation, and amortization	1.50	1.75	1.76

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

The MRD Segment recorded net income of $97.3 million during 2015 compared to net loss of $764.3 million during 2014.

Oil and natural gas revenues for 2015 totaled $374.0 million, a decrease of $35.0 million compared with 2014. Production increased 52.5 Bcfe (approximately 72%) primarily due to drilling activities in North Louisiana. The average realized sales price decreased $2.62 per Mcfe (approximately 47%) due to lower commodity prices. The favorable volume variance contributed to an approximate $293.7 million increase and was offset by $328.7 million decrease due to the unfavorable pricing variances.

Lease operating expenses were $24.9 million and $17.6 million for 2015 and 2014, respectively. On a per Mcfe basis, lease operating expenses decreased to $0.20 for 2015 from $0.24 for 2014 due to increased production volumes and operational efficiency. Certain items, such as direct labor and materials and supplies, generally remain relatively fixed across broad production volume ranges.

DD&A expense for 2015 was $188.7 million compared to $128.2 million for 2014, a $60.5 million increase primarily due to an increase in production volumes related to drilling activities in North Louisiana. The increase was partially offset by a decrease in the DD&A rate as a result of reserves added throughout the year at a higher rate than costs. Increased production volumes caused DD&A expense to increase by an approximate $92.0 million and the change in the DD&A rate between periods caused DD&A expense to decrease by an approximate $31.5 million.

Gathering, processing, and transportation expenses, including affiliates, were $98.0 million and $46.0 million for 2015 and 2014, respectively. The increase of $52.0 million is primarily due to an increase in natural gas and NGL volumes produced and an increase in the associated rates due to cryogenic processing costs associated with new gas processing agreements. On a per Mcfe basis, gathering, processing, and transportation expense, including affiliates, were $0.78 for 2015 compared to $0.63 for 2014. For more information regarding the midstream service agreements, see Note 13 and Note 16 of the Notes to Consolidated and Combined Financial Statements under "Item 8. Financial Statements and Supplementary Data" of this report.

There was no impairment expense recorded in 2015 as compared to $24.6 million for 2014. The 2014 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 2015 was $35.1 million. We recognized $943.9 million of incentive unit compensation expense in 2014, 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.

General and administrative expenses for 2015 were $46.3 million compared to $38.5 million for 2014. General and administrative expenses for 2015 included $2.0 million of acquisition-related costs compared to $2.3 million of acquisition-related costs during 2014. Expense associated with our long-term incentive plan ("LTIP") awards was $8.8 million in 2015 compared to $2.8 million in 2014.

Net gains on commodity derivative instruments of $281.2 million were recognized during 2015, consisting of $170.9 million of cash settlement receipts on expired positions and $92.3 million in cash settlements received on terminated derivatives. These gains also included an $18.0 million increase in the fair value of open positions. 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 positions.

Given the volatility of commodity prices, it is not possible to predict future reported unrealized mark-to-market net gains or losses and the actual net gains or losses that will ultimately be realized upon settlement of the hedge positions in future years. If commodity prices at settlement are lower than the prices of the hedge positions, the hedges are expected to mitigate the otherwise negative effect on earnings of lower oil, natural gas and NGL prices. However, if commodity prices at settlement are higher than the prices of the hedge positions, the hedges are expected to dampen the otherwise positive effect on earnings of higher oil, natural gas and NGL prices and will, in this context, be viewed as having resulted in an opportunity cost.

Net interest expense during 2015 was $39.4 million, including amortization of deferred financing fees of approximately $2.8 million. Net interest expense during 2014 was $50.3 million, including amortization of deferred financing fees of approximately $3.2 million. The decrease in net interest expense is primarily the result of a higher level of indebtedness and higher interest rates during 2014 compared to 2015, including the MRD Senior Notes and the PIK notes.

Average outstanding borrowings under our revolving credit facility were $230.5 million during 2015 and $60.0 million during 2014. Average outstanding borrowings under the predecessor's revolving credit facilities were $116.7 million during 2014. During 2015, we had an average of $600.0 million aggregate principal amount of the MRD Senior Notes issued and outstanding. During 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.

During 2015, we sold certain oil and natural gas properties in Colorado and Wyoming to a third party and recorded a gain of less than $0.1 million. 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.

An extinguishment loss of $23.6 million was recognized related to the redemption of the PIK notes during 2014. 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.

Income tax expense for 2015 was $100.0 million compared to income tax expense of $102.4 million for 2014. The effective tax rate was 50.7% for 2015 compared to negative 15.5% for 2014. The effective tax rate for 2015 differed from the federal statutory income tax rate primarily due to nondeductible incentive unit compensation and state income tax. The effective tax rate for 2014 differed from the federal statutory income tax rate primary due to a pretax loss which was attributable to nondeductible incentive unit compensation and MRD's predecessor being a pass-through entity prior to the initial public offering.

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

The MRD Segment recorded a net loss of $764.3 million during 2014 compared to net income of $91.4 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 $409.1 million, an increase of $189.5 million compared with 2013. Production increased 33.0 Bcfe (approximately 82%) primarily due to drilling activities in North Louisiana. The average realized sales price increased $0.13 per Mcfe primarily due to higher natural gas and NGL prices. The favorable volume variance contributed to an approximate $180.2 million increase and the favorable pricing variances contributed to an approximate $9.3 million increase.

Lease operating expenses were $17.6 million and $17.3 million for 2014 and 2013, respectively. On a per Mcfe basis, lease operating expenses decreased to $0.24 for 2014 from $0.43 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 $128.2 million compared to $70.9 million for 2013, a $57.3 million increase primarily due to increased production volumes related to drilling activities in North Louisiana. Increased production volumes caused DD&A expense to increase by an approximate $58.1 million and the change in the DD&A rate between periods caused DD&A expense to decrease by an approximate $0.8 million.

Gathering, processing, and transportation expenses, including affiliates, were $46.0 million and $17.7 million for 2014 and 2013, respectively. The increase of $28.3 million is primarily due to an increase in natural gas and NGL volumes produced and an increase in the associated rates due to cryogenic processing costs associated with new gas processing agreements. On a per Mcfe basis, gathering, processing, and transportation expenses, including affiliates, were $0.63 for 2014 compared to $0.44 for 2013.

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 $35.0 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 $4.3 million related to the Black Diamond management buyout 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 $38.5 million compared to $35.3 million for 2013. General and administrative expenses for 2014 included $2.3 million of acquisition-related costs compared to $1.6 million of acquisition-related costs during 2013. 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 $3.2 million were recognized during 2013, consisting of $8.5 million of cash settlement receipts offset by a $5.3 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 $24.9 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 $60.0 million during 2014. Average outstanding borrowings under the predecessor’s revolving credit facilities were $116.7 million during 2014 and $204.2 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 during 2014. 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.

Income tax expense for 2014 was $102.4 million compared to an income tax expense of $1.3 million for 2013. The increase in income tax expense was primarily a result of MRD's tax status as a corporation subject to federal and state income tax subsequent to our initial public offering during 2014. The effective tax rate was negative 15.5% for 2014 compared to 1.4% for 2013. The effective tax rate for 2014 differed from the federal statutory income tax rate primary due to the nondeductible incentive unit compensation and MRD's predecessor being a pass-through entity prior to the initial public offering. The effective tax rate for 2013 differed from the federal statutory income tax rate primarily due to MRD's predecessor being a pass-through entity prior to our initial public offering.

MEMP Segment

The MEMP Segment's results of operations for the years ended December 31, 2015, 2014, and 2013 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:

- an acquisition in March 2014 by MEMP of certain oil and natural gas producing properties in the Eagle Ford for a net purchase price of $168.1 million;
- an acquisition in July 2014 by MEMP of certain oil and natural gas liquid properties in Wyoming for a purchase price of approximately $906.1 million; and
- an acquisition by MEMP for the remaining interest in the Beta properties from a third party in November 2015 for approximately $94.6 million.

	For the Year Ended December 31,		
	2015	2014	2013
	(in thousands)		
Oil & natural gas sales	$355,422	$561,677	$391,440
Lease operating	168,199	143,733	94,591
Gathering, processing, and transportation	34,939	31,892	25,055
Exploration	2,317	2,750	1,322
Taxes other than income	25,828	33,141	18,447
Depreciation, depletion, and amortization	195,814	185,955	113,814
Impairment of proved oil and natural gas properties	616,784	407,540	4,072
General and administrative	56,671	49,124	46,665
(Gain) loss on commodity derivative instruments	(462,890)	(492,254)	(26,133)
Interest expense, net	(114,732)	(83,550)	(44,302)
Net income (loss)	(395,491)	115,614	61,005
Natural gas and oil revenue:			
Oil sales	$177,711	$266,370	$174,301
NGL sales	43,102	81,316	60,212
Natural gas sales	134,609	213,991	156,927
Total natural gas and oil revenue	$355,422	$561,677	$391,440
Production Volumes:			
Oil (MBbls)	4,087	3,135	1,797
NGLs (MBbls)	2,820	2,498	1,806
Natural gas (MMcf)	50,875	48,721	41,287
Total (MMcfe)	92,315	82,520	62,907
Average net production (MMcfe/d)	252.9	226.0	172.3
Average sales price:			
Oil (per Bbl)	$43.48	$84.97	$97.00
NGL(per Bbl)	15.28	32.55	33.34
Natural gas (per Mcf)	2.65	4.39	3.80
Total (Mcfe)	$3.85	$6.81	$6.22
Average unit costs per Mcfe:			
Lease operating expense	$1.82	$1.74	$1.50
Gathering, processing, and transportation	0.38	0.39	0.40
Production and ad valorem taxes	0.28	0.40	0.29
General and administrative expenses	0.61	0.60	0.74
Depletion, depreciation, and amortization	2.12	2.25	1.81

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

A net loss of $395.5 million was generated for the year ended December 31, 2015, primarily due to impairments charges offset by significant gains on commodity derivatives. Net income of $115.6 million was generated for the year ended December 31, 2014, primarily due to significant gains on commodity derivatives which were partially offset by impairment charges.

Oil and natural gas sales for 2015 totaled $355.4 million, a decrease of $206.3 million compared with 2014. Production increased 9.8 Bcfe (approximately 12%), primarily from increased drilling activities and volumes associated with third party acquisitions. The average realized sales price decreased $2.96 per Mcfe primarily due to lower period-to-period commodity prices. The favorable volume and unfavorable pricing variance contributed to an approximate $66.6 million increase and $272.9 million decrease in revenues, respectively.

Lease operating expenses were $168.2 million and $143.7 million for the year ended December 31, 2015 and 2014, respectively. In the MEMP Wyoming acquisition, MEMP acquired oil 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 $1.82 for 2015 from $1.74 for 2014 due to 2014 oil acquisitions.

Gathering, processing and transportation expenses were $34.9 million and $31.9 million for 2015 and 2014, respectively. On a per Mcfe basis, gathering, processing and transportation expense were $0.38 for 2015 compared to $0.39 for 2014.

Taxes other than income for 2015 totaled $25.8 million, a decrease of $7.3 million compared with 2014 primarily due to a decrease in commodity prices. On a per Mcfe basis, taxes other than income decreased to $0.28 for 2015 from $0.40 for 2014 due to a decrease in commodity prices.

DD&A expense for 2015 was $195.8 million compared to $186.0 million for 2014, a $9.8 million increase primarily due to increased production volumes related to third party acquisitions and MEMP's drilling program. Increased production volumes caused DD&A expense to increase by approximately $22.0 million and the change in the DD&A rate between periods caused DD&A expense to decrease by approximately $12.2 million.

MEMP recognized $616.8 million of impairments in 2015 primarily related to certain properties in East Texas, South Texas, the Permian Basin, Wyoming and Colorado. The estimated future cash flows expected from these properties were compared to their carrying values and determined to be unrecoverable primarily due to declining commodity prices. During 2014, MEMP recorded $407.5 million of impairments related 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 due to a downward revision of estimated proved reserves as a result of declining commodity prices and updated well performance data. For additional information, see Note 4 of the Notes to Consolidated and Combined Financial Statements included under "Item 8. Financial Statements and Supplementary Data."

General and administrative expenses for 2015 were $56.7 million, which included $10.8 million of non-cash unit-based compensation expense, $1.9 million of acquisition-related costs and a $0.8 million loss on a previous corporate office lease. General and administrative expenses for 2014 totaled $49.1 million and included $7.9 million of non-cash unit-based compensation expense, $4.4 million of acquisition-related costs and $1.8 million of losses on a previous corporate office lease.

Net gains on commodity derivative instruments of $462.9 million were recognized during 2015, consisting of $254.0 million of cash settlement received on expired positions, and a $208.9 million increase in the fair value of open positions. 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 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 $114.7 million during 2015, including amortization of deferred financing fees of approximately $6.1 million and accretion of net discount associated with the senior notes of $2.4 million. Net interest expense totaled $83.6 million during 2014, including amortization of deferred financing fees of approximately $4.2 million. The increase in net interest expense is primarily due to higher aggregate principal amount of MEMP's senior notes issued and outstanding during 2015 compared to 2014.

Average outstanding borrowings under MEMP's revolving credit facility were $652.2 million during 2015 compared to $413.6 million during 2014. For 2015, MEMP had an average of $1.2 billion aggregate principal amount of MEMP's senior notes issued and outstanding. For 2014, MEMP had an average of $950.7 million aggregate principal amount of MEMP's senior notes issued and outstanding.

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

Net income of $115.6 million was generated for the year ended December 31, 2014, primarily due to gains on commodity derivatives offset by impairment charges. Net income of $61.0 million was generated for the year ended December 31, 2013.

Oil and natural gas sales for 2014 totaled $561.7 million, an increase of $170.2 million compared with 2013. Production increased 19.6 Bcfe (approximately 31%), primarily from volumes associated with third party acquisitions. The average realized sales price increased $0.59 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 $122.0 million and $48.2 million increase in revenues, respectively.

Lease operating expenses were $143.7 million and $94.6 million for 2014 and 2013, respectively. In the July 2014 Wyoming acquisition, MEMP acquired oil 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 $1.74 for 2014 from $1.50 for 2013.

Taxes other than income for 2014 totaled $33.1 million, an increase of $14.7 million compared with 2013 primarily due to an increase in production volumes and ad valorem tax rates. On a per Mcfe basis, taxes other than income increased to $0.40 for 2014 from $0.29 for 2013 due to higher production tax rates on a per Mcfe basis for production from MEMP's Wyoming properties.

DD&A expense for 2014 was $186.0 million compared to $113.8 million for 2013, a $72.2 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 $35.5 million and the change in the DD&A rate between periods caused DD&A expense to increase by an approximate $36.7 million.

MEMP recognized $407.5 million of impairments during 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. MEMP recorded $4.1 million of impairments during 2013 related to certain properties in South Texas. 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.

General and administrative expenses for 2014 were $49.1 million and included $7.9 million of non-cash unit-based compensation expense and $4.4 million of acquisition-related costs and a $1.8 million allocated loss on a previous corporate office lease. General and administrative expenses for 2013 totaled $46.7 million and included $3.6 million of non-cash unit-based compensation expense and $6.7 million of acquisition-related costs.

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 $26.1 million were recognized during 2013, consisting of $23.6 million of cash settlement receipts, in addition to a $2.5 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 $44.3 million during 2013, including gains on interest rate swaps of $1.5 million and amortization of deferred financing fees of approximately $6.0 million. The increase in net interest expense is primarily the result of higher level of indebtedness during 2014 compared to 2013.

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 $101.3 million during 2013, which included $80.0 million of borrowings related to Classic. During 2014, MEMP had an average of $950.7 million aggregate principal amount of MEMP's senior notes issued and outstanding. During 2013, MEMP had an average of $342.2 million aggregate principal amount of MEMP's senior notes issued and outstanding.

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 (other than MEMP GP). 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 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 2016 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, 2015, we had $1.6 million of cash and cash equivalents and $577.0 million of available borrowings under our revolving credit facility. As of December 31, 2015, we had a working capital balance of $204.2 million, which includes a net asset balance of $274.1 million associated with our derivatives and other financial instruments. As of December 31, 2015, the borrowing base under our revolving credit facility was $1.0 billion and we had $423.0 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 2016. 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 all or 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.

MRD Segment’s total capital expenditures were $880.0 million for the year ended December 31, 2015 and included $368.7 million associated with acquisitions and unproved leasehold additions. In 2015, MRD spent approximately 100% of its capital expenditures in the Terryville Complex. Our current estimated drilling and completion capital expenditure budget for 2016 is $325 million to $375 million, with substantially all capital expenditures dedicated to the Terryville Complex.

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 $1.0 billion as of December 31, 2015. 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, 2015.

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 $1.175 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 a base indenture and supplements thereto.

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 a base indenture and supplement thereto.

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

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 the Year Ended December 31,		
	2015	2014	2013
	(In thousands)		
Net cash provided by operating activities:	$416,145	$226,906	$75,905
Net cash used in investing activities:			
Acquisition of oil and natural gas properties	$(291,536)	$(93,909)	$(67,098)
Additions to oil and gas properties	(594,901)	(376,123)	(185,194)
Additions to other property and equipment	(3,789)	(16,969)	(2,432)
Equity investments in MEMP Segment	—	(570)	(521)
Other financial instruments	(46,106)	—	—
Distributions received from MEMP Segment related to partnership interests	252	6,144	26,006
Decrease (increase) in restricted cash	—	49,946	(49,347)
Proceeds from the sale of oil and gas properties to third parties	13,612	6,700	151,187
Proceeds from the sale of MEMP common units	—	—	135,012
Other	—	(516)	—
Net cash provided by (used in) investing activities	$(922,468)	$(425,297)	$7,613
Net cash provided by financing activities:			
Advances on revolving credit facilities	$798,000	$1,300,800	$174,400
Payments on revolving credit facilities	(558,000)	(1,320,900)	(200,500)
Proceeds from issuance of senior notes	—	600,000	343,000
Borrowings under second lien credit facility	—	—	325,000
Termination of second lien credit facility	—	(328,282)	—
Redemption of senior notes	—	(351,808)	—
Deferred financing costs	(1,498)	(18,840)	(20,250)
Purchase of additional interest in subsidiaries	—	(3,292)	(13,865)
Proceeds from public offering	242,880	408,500	—
Costs incurred in conjunctions with public offering	(4,773)	(28,373)	—
Contributions from MEMP Segment	78,396	58,766	180,260
Contribution related to sale of assets to NGP affiliates	—	1,165	—
Distribution to noncontrolling interest	—	(325)	(7,446)
Distribution to Funds	—	—	(732,362)
Distribution to MEMP Segment	(1,912)	(5,990)	(89,570)
Distribution to MRD Holdco	—	(59,803)	—
Distribution to other NGP affiliates	—	(99,463)	—
Distribution made by previous owners	—	—	(2,590)
Repurchases of shares	(51,197)	(161)	—
Other	—	269	(4,593)
Net cash provided by (used in) financing activities	$501,896	$152,263	$(48,516)

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

Operating Activities. Net cash flows provided by operating activities were $416.1 million during 2015 compared to $226.9 million during 2014. Production increased 52.5 Bcfe (approximately 72%) and average realized sales price decreased $2.62 per Mcfe as previously discussed above under “Results of Operations—MRD Segment.” Net cash provided by operating activities included $92.3 million of cash receipts on terminated derivative instruments and $46.2 million of premiums paid for derivatives. Cash paid for interest during 2015 was $18.8 million compared to $67.0 million during 2014 due to timing of interest payments and lower interest rates. During 2014, compensation expense of approximately $26.7 million was paid in cash related to WildHorse Resources' incentive units.

Investing Activities. Total cash used in investing activities was $922.5 million during 2015 compared to $425.3 million during 2014. Cash used for the acquisition of oil and gas properties was $291.5 million during 2015 compared to $93.9 million used in 2014. The 2015 and 2014 acquisitions were for certain properties located in Louisiana. Cash used for additions to oil and gas properties was $594.9 million during 2015 compared to $376.1 million during 2014, which consisted primarily of drilling and completion activities in North Louisiana. Additions to other property and equipment were $3.8 million during 2015 compared to $17.0 million during 2014. Additions to other financial instruments was $46.1 million in 2015. Distributions of $0.2 million and $6.1 million were received from MEMP related to partnership interest owned by the MRD Segment during 2015 and 2014, respectively. In April 2015, we sold certain oil and natural gas properties to a third party in Colorado and Wyoming for approximately $13.6 million. 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. 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.

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 borrowings under our revolving credit facility were $240.0 million during 2015. Amounts borrowed under our revolving credit facility were primarily used for additions to oil and natural gas properties and general corporate purposes. Net repayments under the revolving credit facility were $20.1 million during 2014. 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. In connection with the closing of our initial public offering, WildHorse Resources' $325.0 million second lien term loan was repaid in full, including a premium of approximately $3.3 million.

On September 25, 2015, MRD issued 13,800,000 shares of common stock (including 1,800,000 shares of common stock sold pursuant to the full exercise of the underwriters' option to purchase additional shares of common stock) to the public generating total net proceeds of approximately $238.1 million after deducting underwriting discounts and offering expenses. The net proceeds temporarily reduced borrowings outstanding under our revolving credit facility.

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.

The MRD Segment received $78.4 million from the MEMP Segment in connection with the Property Swap. MRD made deemed distributions of $1.9 million and $6.0 million to MEMP related to the properties MEMP acquired in the Property Swap transaction during 2015 and 2014, respectively. 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.

In connection with our initial public offering, certain former management members of WildHorse Resources, including Mr. Graham, 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.

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.

Total payments remitted for employees' tax obligations to the appropriate taxing authorities were approximately $1.2 million during 2015 upon vesting of the restricted common stock. The Company repurchased 2,888,684 shares of its common stock under its December 2014 repurchase program for an aggregate price of $50.0 million during 2015, which exhausted the December 2014 repurchase program. The Company has retired all of the shares of common stock repurchased and those shares of common stock are no longer issued or outstanding.

Deferred financing costs of approximately $1.5 million and $18.8 million were incurred during 2015 and 2014, respectively.

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

Operating Activities. Net cash flows provided by operating activities were $226.9 million during 2014 compared to $75.9 million during 2013. Production increased 33.0 Bcfe (approximately 82%) and average realized sales price increased $0.13 per Mcfe as previously discussed above under "Results of Operations—MRD Segment." Cash paid for interest during 2014 was $67.0 million compared to $18.5 million during 2013. During 2014, compensation expense of approximately $26.7 million was paid in cash related to WildHorse Resources' incentive units compared to $35.0 million in 2013 related to incentive units.

Investing Activities. Total cash used in investing activities was $425.3 million during 2014 compared to $7.6 million provided 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 $376.1 million during 2014 compared to $185.2 million during 2013, which consisted primarily of drilling and completion activities in North Louisiana. 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 $26.1 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.

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 $28.6 million to MRD LLC during 2013.

In connection with our initial public offering, certain former management members of WildHorse Resources, including Mr. Graham, 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 the MEMP Segment during 2013 of $89.6 million were primarily used to repay indebtedness and terminate the revolving credit facility attributable to Classic. 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.

MEMP Segment

	For the Year Ended December 31,		
	2015	2014	2013
	(In thousands)		
Net cash provided by operating activities	$216,751	$254,273	$201,703
Net cash used in investing activities:			
Acquisition of oil and natural gas properties	$(91,160)	$(1,083,761)	$(38,664)
Additions to oil and gas properties	(241,299)	(298,274)	(174,821)
Additions to other property and equipment	—	(98)	(238)
Additions to restricted investments	(5,690)	(3,976)	(5,361)
Proceeds from the sale of oil and gas properties to third parties	580	—	4,525
Net cash provided by (used in) investing activities	$(337,569)	$(1,386,109)	$(214,559)
Net cash provided by financing activities			
Advances on revolving credit facilities	$562,000	$1,446,000	$958,355
Payments on revolving credit facilities	(138,000)	(1,137,000)	(1,565,537)
Proceeds from the issuance of senior notes	—	492,425	688,563
Repurchase of senior notes	(2,914)	—	—
Deferred financing costs	(341)	(11,494)	(20,924)
Capital contributions from previous owners	—	—	7,233
Contribution from NGP affiliate	860	—	2,013
Contribution from MRD Segment	1,912	5,990	89,570
Contribution from general partner	—	570	521
Proceeds from public equity offering	—	553,288	511,204
Costs incurred in conjunction with issuance of common units	—	(12,510)	(21,066)
Purchase of additional interest in MEMP's subsidiaries	(5,946)	—	—
Distributions to partners	(163,259)	(154,852)	(96,643)
Distributions to MRD Segment	(78,396)	(58,766)	(180,260)
Distributions to NGP affiliates	—	—	(355,495)
Distributions made by previous owners	—	—	(2,552)
Restricted units returned to plan	(1,285)	(1,012)	—
Repurchased units under unit repurchase program	(54,184)	(11,531)	—
Other		—	(9,013)
Net cash provided by (used in) financing activities	$120,447	$1,111,108	$5,969

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

Operating Activities. Net income decreased by $511.1 million as further discussed above under “Results of Operations—MEMP Segment,” and net cash provided by operating activities decreased by $37.5 million. Cash paid for interest during 2015 was $107.3 million compared to $63.7 million during 2014. Net cash provided by operating activities in 2015 included $250.0 million of cash receipts on expired derivative instruments and MEMP had a $19.7 million decrease in cash flow attributable to the timing of cash receipts and disbursements related to operating activities during 2015 compared to 2014.

Investing Activities. Net cash used in investing activities during 2015 was $337.6 million, of which $100.7 million was used to acquire oil and natural gas properties from third parties and $241.3 million was used for additions to oil and gas properties. MEMP received a post-closing settlement of $9.6 million during 2015 related to the July 2014 Wyoming acquisition, which has been netted against the amount used to acquire oil and natural gas properties. Cash used in investing activities during 2014 was $1.39 billion, of which $1.08 billion was used to acquire oil and natural gas properties from third parties and $298.3 million was used for additions to oil and 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 2015 and 2014, additions to restricted investments were $5.7 million and $4.0 million, respectively. See Note 7 of the Notes to Consolidated and Combined Financial Statements included under "Item 8. Financial Statements and Supplementary Data" for additional information regarding MEMP's restricted investments.

Financing Activities. Distributions to partners during 2015 were $163.3 million compared to $154.9 million during 2014, of which the MRD Segment received $0.2 million during 2015 compared to $6.1 million during 2014. The increase in total distributions is primarily due to an increase in MEMP's outstanding units between periods partially offset by a decrease in the distribution paid during the fourth quarter of 2015. The decrease in distributions to the MRD Segment is due to the distribution of 5,360,912 subordinated units to MRD Holdco in June 2014 in connection with our initial public offering.

The MEMP Segment distributed $78.4 million to the MRD Segment in connection with the Property Swap acquisition. MEMP received a contribution of $1.9 million and $6.0 million from the MRD Segment related to the properties MEMP acquired in the Property Swap transaction during 2015 and 2014, respectively. The MEMP Segment distributed $43.8 million to the MRD Segment, of which $33.9 million was related to the acquisition of certain oil and gas properties in East Texas during 2014 by MEMP and $9.9 million was a deemed contribution related to the properties MEMP acquired in the Property Swap. MEMP paid $15.0 million to MRD in connection with MEMP's October 2014 acquisition of certain oil and gas properties in the Rockies.

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, including MEMP GP's proportional capital contributions, were primarily used to repay borrowings on MEMP's revolving credit facility.

MEMP had net borrowings of $424.0 million under its revolving credit facility during 2015 that were primarily used to fund: (i) the purchase of the remaining interest in the Beta properties from a third party in November 2015, (ii) the Property Swap, (iii) common unit repurchases and (iv) MEMP's drilling program. MEMP had borrowings of $1.45 billion under MEMP's revolving credit facility during 2014 that were used primarily to fund the Eagle Ford and Wyoming acquisitions and to fund MEMP's drilling program. Deferred financing costs of approximately $0.3 million were incurred during 2015 compared to approximately $11.5 million during 2014.

MEMP repurchased $54.2 million in common units during 2015, which represented a repurchase and retirement of 3,641,721 common units under the MEMP Repurchase Program (including common unit repurchases of $1.4 million, representing 93,800 common units, accrued at December 31, 2014). MEMP repurchased a principal amount of approximately $3.0 million of the 2022 Senior Notes at a price of 83.000% of the face value of the 2022 Senior Notes in January 2015, of which $2.9 million was classified as a financing outflow representing repayment of the original proceeds and $0.3 million classified as an operating inflow.

Proceeds of $492.4 million from the issuances of senior notes were generated during 2014 and used to repay borrowings outstanding under MEMP's revolving credit facility.

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

Operating Activities. Net income increased by $54.6 million as further discussed above under "Results of Operations—MEMP Segment," and net cash provided by operating activities increased by $52.6 million. Cash paid for interest during 2014 was $63.7 million compared to $42.6 million during 2013. Net cash provided by operating activities included $7.8 million period-to-period decrease 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 $1.39 billion, of which $1.08 billion was used to acquire oil and natural gas properties from third parties and $298.3 million was used for additions to oil and gas properties. Cash used in investing activities during 2013 was $214.6 million, of which $38.7 million was used to acquire oil and natural gas properties from a third parties and $174.8 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. Contributions from the MRD Segment of $89.6 million during 2013 were primarily used to repay indebtedness and terminate the revolving credit facility attributable to Classic.

MEMP had net payments of $607.2 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.

Contractual Obligations

In the table below, we set forth our consolidated contractual obligations as of December 31, 2015 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	2016	2017-2018	2019-2020	Thereafter
Revolving credit facility (1)					
MRD Segment	$423,000	$—	$—	$423,000	$—
MEMP Segment	836,000	—	836,000	—	—
Estimated interest payments (2)					
MRD Segment	28,426	8,122	16,243	4,061	—
MEMP Segment	39,877	17,723	22,154	—	—
Senior Notes (3)					
MRD Segment	846,750	35,250	70,500	70,500	670,500
MEMP Segment	1,729,729	87,543	175,086	175,086	1,292,014
Asset retirement obligation (4)					
MRD Segment	9,249	354	2,550	1,090	5,255
MEMP Segment	164,164	1,175	10,875	8,691	143,423
Decommissioning trust agreement (5)					
MEMP Segment	7,992	7,992	—	—	—
Operating leases (6)					
MRD Segment	45,322	10,509	16,711	12,979	5,123
MEMP Segment	15,004	9,904	611	589	3,900
Drilling services					
MRD Segment	34,740	34,229	511	—	—
Midstream service fees (7)					
MRD Segment	1,306,187	142,461	231,990	236,280	695,456
MEMP Segment	35,788	5,121	10,227	10,213	10,227
CO_2 minimum purchase commitment (8)					
MEMP Segment	30,307	7,393	12,580	10,334	—
Other					
MEMP Segment	4,662	4,662	—	—	—
MRD subtotal	2,693,674	230,925	338,505	747,910	1,376,334
MEMP subtotal	2,863,523	141,513	1,067,533	204,913	1,449,564
Total	5,557,197	372,438	1,406,038	952,823	2,825,898

(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, 2015. In calculating these amounts, we applied the weighted-average interest rate during 2015 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 2015 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, 2015.

(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, 2015 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 as well as equipment rental. 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 midstream service providers. See the Notes to the Consolidated and Combined Financial Statements under “Item 8. Financial Statements and Supplementary Data,” contained herein, for information regarding midstream service provider fees.

(8) Represents a firm agreement to purchase CO_2 volumes related to MEMP’s Bairoil properties in Wyoming.

Off–Balance Sheet Arrangements

As of December 31, 2015, 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 believe we will continue to consolidate MEMP and become subject to the VIE primary beneficiary disclosure requirements. The deconsolidation of MEMP would have a material impact on our consolidated financial statements and related disclosures in the event there is a reconsideration event that triggers deconsolidation.

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 into 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, 2015, the MRD Segment had the following open commodity positions (excluding embedded derivatives):

	2016	2017
Natural Gas Derivative Contracts:		
Fixed price swap contracts:		
Average Monthly Volume (MMBtu)	2,570,000	1,770,000
Weighted-average fixed price	$4.09	$4.24
Collar contracts:		
Average Monthly Volume (MMBtu)	1,100,000	1,050,000
Weighted-average floor price	$4.00	$4.00
Weighted-average ceiling price	$4.71	$5.06
Purchased put option contracts:		
Average Monthly Volume (MMBtu)	6,000,000	5,350,000
Weighted-average strike price	$3.51	$3.48
Weighted-average deferred premium paid	$(0.34)	$(0.32)
TGT Z1 basis swaps:		
Average Monthly Volume (MMBtu)	1,120,000	200,000
Spread - Henry Hub	$(0.10)	$(0.08)
Crude Oil Derivative Contracts:		
Fixed price swap contracts:		
Average Monthly Volume (Bbls)	35,583	28,000
Weighted-average fixed price	$83.58	$84.70
Collar contracts:		
Average Monthly Volume (Bbls)	27,000	—
Weighted-average floor price	$80.00	$—
Weighted-average ceiling price	$99.70	$—
NGL Derivative Contracts:		
Fixed price swap contracts:		
Average Monthly Volume (Bbls)	353,399	—
Weighted-average fixed price	$39.68	$—

During the year ended December 31, 2015, MRD restructured its existing 2018 crude oil and natural gas hedges for crude oil and NGL swaps that will settle in 2016. Cash settlements of approximately $92.3 million from the terminated 2018 positions were received and applied as premiums for the new crude oil and NGL swaps. Certain contracts are classified as hybrid financial instruments, which require bifurcation, based on the relationship between the fixed swap price and the market price at the restructure dates.

At December 31, 2015, the MRD Segment had the following open embedded derivative positions:

	2016
Oil Hybrid Contracts:	
Fixed price swap contracts:	
Average Monthly Volume (Bbls)	27,080
Weighted-average fixed price	$46.51
Initial net investment price	62.16
Total contract swap price	$108.67
NGL Hybrid Contracts:	
Fixed price swap contracts:	
Average Monthly Volume (Bbls)	83,101
Weighted-average fixed price	$15.84
Initial net investment price	25.98
Total contract swap price	$41.82

In February 2015, MEMP restructured a portion of its commodity derivative portfolio by effectively terminating "in-the-money" crude oil derivatives settling in 2015 through 2017 and entering into NGL derivatives with the same tenor. Cash settlement receipts of approximately $27.1 million from the termination of the crude oil derivatives were applied as premiums for the new NGL derivatives. In November 2015, MEMP had cash settlement receipts of $16.5 million from the termination of certain WTI crude oil derivatives that were applied as premiums for new Brent crude oil derivatives. As a part of MEMP's 2015 Beta Acquisition, MEMP acquired $4.6 million in crude oil derivatives. These derivatives were subsequently restructured by terminating "in-the-money" crude oil derivatives settling in 2015 through 2016 and entering into new crude oil derivatives. Cash settlement receipts of approximately $4.4 million from the termination of the crude oil derivatives were applied as premiums for the new crude oil swaps.

At December 31, 2015, the MEMP Segment had the following open commodity positions:

	2016	2017	2018	2019
Natural Gas Derivative Contracts:				
Fixed price swap contracts:				
Average Monthly Volume (MMBtu)	3,592,442	3,350,067	3,060,000	2,814,583
Weighted-average fixed price	$4.14	$4.06	$4.18	$4.31
Basis swaps:				
Average Monthly Volume (MMBtu)	3,578,333	2,210,000	1,315,000	900,000
Spread	$(0.07)	$(0.04)	$(0.02)	$0.01
Crude Oil Derivative Contracts:				
Fixed price swap contracts:				
Average Monthly Volume (Bbls)	304,813	301,600	312,000	160,000
Weighted-average fixed price	$85.48	$85.00	$83.74	$85.52
Basis swaps:				
Average Monthly Volume (Bbls)	140,000	67,500	—	—
Spread	$(10.02)	$(7.82)	$—	$—
NGL Derivative Contracts:				
Fixed price swap contracts:				
Average Monthly Volume (Bbls)	213,100	43,300	—	—
Weighted-average fixed price	$35.64	$37.55	$—	$—

The MEMP Segment's basis swaps as of December 31, 2015 included in the table above are presented on a disaggregated basis below:

	2016	2017	2018	2019
Natural Gas Derivative Contracts:				
NGPL TexOk basis swaps:				
Average Monthly Volume (MMBtu)	3,003,333	1,800,000	1,200,000	900,000
Spread - Henry Hub	$(0.07)	$(0.07)	$(0.03)	$0.01
HSC basis swaps:				

Average Monthly Volume (MMBtu)	135,000	115,000	115,000	—
Spread - Henry Hub	$0.07	$0.14	$0.15	$—
CIG basis swaps:				
Average Monthly Volume (MMBtu)	170,000	—	—	—
Spread - Henry Hub	$(0.30)	$—	$—	$—
TETCO STX basis swaps:				
Average Monthly Volume (MMBtu)	270,000	295,000	—	—
Spread - Henry Hub	$0.06	$0.03	$—	$—
Crude Oil Derivative Contracts:				
Midway-Sunset basis swaps:				
Average Monthly Volume (Bbls)	100,000	37,500	—	—
Spread - Brent	$(12.29)	$(12.20)	$—	$—
Midland basis swaps:				
Average Monthly Volume (Bbls)	40,000	30,000	—	—
Spread - WTI	$(4.34)	$(2.35)	$—	$—

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	$—
Purchased put option contracts:				
Average Monthly Volume (MMBtu)	3,000,000	4,100,000	3,450,000	2,850,000
Weighted-average strike price	$3.75	$3.75	$3.75	$3.75
Weighted-average deferred premium paid	$(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:				