Memorial Resource Development Corp.
Form 424B1
November 14, 2014
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Filed pursuant to Rule 424(b)(1)
Registration No. 333-199103

PROSPECTUS

30,000,000 Shares

Memorial Resource Development Corp.

Common Stock

$23.00 per share

MRD Holdco LLC and certain former management members of WildHorse Resources, LLC (collectively, the selling stockholders) are offering 30,000,000 shares of Memorial Resource Development Corp. s common stock. The selling stockholders have granted the underwriters a 30-day option to purchase up to an additional 4,500,000 shares of common stock. We will not receive any proceeds from the sale of shares by the selling stockholders, including any shares that the selling stockholders may sell pursuant to the underwriters option to purchase additional shares of common stock.

Our common stock is listed on the NASDAQ Global Select Market under the symbol MRD. We are a controlled company as defined under the NASDAQ listing rules because the group consisting of affiliates of Natural Gas Partners beneficially owns over 50% of our shares of outstanding common stock. See Principal and Selling Stockholders.

On November 12, 2014, the last reported sale price of our common stock on the NASDAQ Global Select Market was $23.53 per share.

Investing in our common stock involves risks that are described in the Risk Factors section beginning on page 23 of this prospectus.

We are an emerging growth company as that term is used in the Jumpstart Our Business Startups Act of 2012, and as such, we have elected to take advantage of certain reduced public company reporting requirements for this prospectus and future filings. See Risk Factors and Summary Emerging Growth Company Status.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed upon the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.

	Per Share	Total
Public Offering Price	$ 23.00	$ 690,000,000
Underwriting Discounts and Commissions(1)	$ 0.7475	$ 22,425,000
Proceeds, Before Expenses, to the Selling Stockholders	$ 22.2525	$ 667,575,000

(1) See Underwriting for a description of underwriting compensation payable in connection with this offering.

The underwriters expect to deliver the shares of common stock on or about November 18, 2014.

Joint Book-Running Managers

Citigroup **Barclays**
BofA Merrill Lynch **BMO Capital Markets** **Goldman, Sachs & Co.** **J.P. Morgan**
Raymond James **RBC Capital Markets** **Wells Fargo Securities**

Co-Managers

Credit Suisse	**Scotiabank / Howard Weil**	**Simmons & Company International**	**Stephens Inc.**
Stifel	**Wunderlich Securities**	**Credit Agricole CIB**	**Natixis**

The date of this prospectus is November 12, 2014.

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You should rely only on the information contained in this prospectus. Neither we, the selling stockholders, nor the underwriters have authorized any person to provide you with any information or represent anything about us or this offering that is not contained in this prospectus. If given or made, any such other information or representation should not be relied upon as having been authorized by us. The selling stockholders are not making an offer in any jurisdiction where an offer or sale is not permitted. The information contained in this prospectus is current only as of its date.

Commonly Used Defined Terms

As used in this prospectus, 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;

- selling stockholders refers to MRD Holdco LLC and certain former management members of WildHorse Resources, LLC named herein;

- 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, our subsidiary, subsequent to our initial public offering;

- WildHorse Resources refers to WildHorse Resources, LLC, which owns our interest in the Terryville Complex and is our 100% owned subsidiary;

- 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 described beginning on page 11 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 or Classic Pipeline);

- 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 immaterial midstream assets in North Louisiana; and

Classic Pipeline refers to Classic Pipeline & Gathering, LLC, a subsidiary of MRD Holdco that owns certain immaterial midstream assets in Texas.

Industry and Market Data

The market data and certain other statistical information used throughout this prospectus are based on independent industry publications, government publications or other published independent sources. Some data is

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also based on our good faith estimates. Although we believe these third-party sources are reliable and that the information is accurate and complete, neither we nor the selling stockholders have independently verified the information.

Equivalency

This prospectus presents certain production and reserves-related information on an equivalency basis. When we refer to oil and natural gas in equivalents, we are doing so to compare quantities of oil with quantities of natural gas. In calculating equivalents, we use a generally recognized standard in which one Bbl of oil and/or NGLs is equivalent to six Mcf of natural gas. This calculation is based on an approximate energy equivalency and does not imply or reflect a value or price relationship.

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SUMMARY

This summary highlights information appearing elsewhere in this prospectus. You should read the entire prospectus carefully, including Risk Factors beginning on page 23 and the historical and pro forma financial statements and the related notes to those financial statements. Certain oil and gas industry terms, including the terms proved reserves, probable reserves and possible reserves, used in this prospectus are defined in the Glossary of Oil and Natural Gas Terms in Appendix A of this prospectus.

Because we control MEMP through our ownership of its general partner, we are required to consolidate MEMP for accounting and financial reporting purposes even though we only own a minority of its limited partner interests. Our financial statements include two reportable business segments: (i) the MRD Segment, which reflects all of our operations except for MEMP and its subsidiaries, and (ii) the MEMP Segment, which reflects the operations of MEMP and its subsidiaries. Except with respect to our consolidated and combined financial statements or as otherwise indicated, the description of our business, properties, strategies and other information in this summary does not include the business, properties or results of operations of BlueStone, MRD Royalty, MRD Midstream and Classic Pipeline (the assets of which are included in our predecessor but were not conveyed to us in the restructuring transactions) or MEMP. Our proved reserves as of December 31, 2013 have been prepared by Netherland, Sewell & Associates, Inc., our independent reserve engineers (NSAI), and our probable and possible reserves as of December 31, 2013 have been prepared by our internal reserve engineers and audited by NSAI, all of which are reflected in our reserve reports (which we collectively refer to as our reserve report), summaries of which are included in Appendices B-1 and B-2 of this prospectus. Our proved reserves within the Terryville Complex as of September 30, 2014 have been prepared by NSAI (which we refer to as our recent reserve report), a summary of which is included in Appendix C of this prospectus.

Information expressed on a pro forma basis in this summary gives effect to certain transactions as if they had occurred on September 30, 2014 for pro forma balance sheet purposes and on January 1, 2013 for pro forma statements of operations purposes. For a description of these transactions, please read Summary Historical Consolidated and Combined Pro Forma Financial Data and Corporate History and Structure.

Overview

We are an independent natural gas and oil company focused on the exploitation, development, and acquisition of natural gas, NGL and oil properties with a majority of our activity in the Terryville Complex of North Louisiana, where we are targeting overpressured, liquids-rich natural gas opportunities in multiple zones in the Cotton Valley formation. As of December 31, 2013, our total leasehold position was 347,458 gross (205,818 net) acres, of which 60,041 gross (51,522 net) acres are in what we believe to be the core of the Terryville Complex. We are focused on creating shareholder value primarily through the development of our sizeable horizontal inventory. As of December 31, 2013, we had 1,582 gross (1,091 net) identified horizontal drilling locations, of which 1,431 gross (994 net) identified horizontal drilling locations are located in the Terryville Complex. These total gross identified horizontal drilling locations represent an inventory of over 42 years based on our expected 2014 drilling program. We believe our inventory to be repeatable and capable of generating high returns based on the extensive production history in the area, the results of our horizontal wells drilled to date, and the consistent reservoir quality across multiple target formations.

As of December 31, 2013, we had estimated proved, probable and possible reserves of approximately 1,126 Bcfe, 800 Bcfe and 1,711 Bcfe, respectively. As of such date, we operated 98% of our proved reserves, 71% of which were natural gas. For the nine months ended September 30, 2014, 56% of our pro forma MRD Segment revenues were attributable to natural gas production, 22% to NGLs and 22% to oil. For the nine months ended September 30, 2014, we generated pro forma MRD Segment Adjusted EBITDA of $259 million and pro forma net loss of $914 million, and made pro forma capital expenditures of $268 million. For the year ended

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December 31, 2013, we generated pro forma MRD Segment Adjusted EBITDA of $159 million and pro forma net loss of $2.9 million, and made pro forma total capital expenditures of $203 million. Please see Summary Historical Consolidated and Combined Pro Forma Financial Data Adjusted EBITDA for an explanation of the basis for the pro forma presentation and our use of Adjusted EBITDA to measure the MRD Segment s profitability.

Our average net daily production for the nine months ended September 30, 2014 was approximately 208 MMcfe/d (approximately 76% natural gas, 17% NGLs and 7% oil) and our reserve life was 14.8 years. The Terryville Complex represented 84% of our total net production for the nine months ended September 30, 2014. As of December 31, 2013, we produced from 95 horizontal wells and 800 vertical wells. Since January 1, 2014, in the Terryville Complex we have completed and brought online 21 horizontal wells through September 30, 2014, bringing our total number of producing horizontal wells to 41 in our primary formations.

The following chart provides information regarding our production growth and the increasing proportion of our horizontal well production since the beginning of 2012.

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. To date, operators have drilled over 600 horizontal Cotton Valley wells. Some large, analogous redevelopment projects in the Cotton Valley include the Nan-Su-Gail Field in Freestone County, East Texas, where over 40 horizontal wells have been drilled by operators such as Devon Energy Corporation and Marathon Oil Corporation, and the Carthage

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Complex in Panola County, East Texas, where operators such as ExxonMobil Corporation, BP America, Memorial Production Partners LP and Anadarko Petroleum Corporation have drilled over 153 horizontal wells.

Cotton Valley Terryville Complex Horizontal Redevelopment

We are currently engaged in the horizontal redevelopment of the Terryville Complex in Lincoln Parish, Louisiana utilizing horizontal drilling and completion techniques similar to those employed at the Nan-Su-Gail Field, Carthage Complex in East Texas and other major resource plays across the United States. We have assembled a largely contiguous acreage position in the Terryville Complex of approximately 60,041 gross (51,522 net) acres as of December 31, 2013. The majority of our current and planned development is focused in and around what we believe to be the core of the Terryville Complex.

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 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. We intend to dedicate approximately $304 million of our $351 million drilling and completion budget in 2014 to develop multiple zones within the Terryville Complex, where we expect to drill 33 gross (29 net) horizontal wells and 3 gross (2.7 net) vertical wells. Our horizontal redevelopment program in the Terryville Complex will be focused on increasing our well performance and recoveries.

Within the Terryville Complex, as of December 31, 2013, we had 945 Bcfe, 688 Bcfe and 1,643 Bcfe of estimated proved, probable and possible reserves, respectively, and a drilling inventory consisting of 1,431 gross (994 net) identified horizontal drilling locations, including 91 gross (72 net) drilling locations to which we have attributed proved undeveloped reserves as of December 31, 2013. Since initiating our horizontal drilling program in 2011, we have drilled 44 gross (38 net) horizontal wells. Within the Terryville Complex, on a proved reserves basis, we operate approximately 99% of our existing acreage and hold an average working interest of approximately 74% across our acreage. Our high operating control allows us to more efficiently and economically manage the redevelopment of this extensive resource.

We believe seismic data, as well as information gathered from the results of our existing 275 vertical and 46 horizontal wells throughout the field, support the existence of at least ten stacked pay zones across the Terryville Complex. Our redevelopment program currently targets four of the stacked 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 400 to 890 feet across our acreage position. We believe the overpressured nature of this section of the Cotton Valley formation is highly productive when accessed through horizontal drilling and fracture stimulation technologies. These qualities, when combined with the liquids-rich nature of the natural gas, high initial rates of production and competitive well costs, produce what we believe to be amongst the highest rate of return wells in the nation. Further, there are additional opportunities for redevelopment in the zones above the four main zones. NSAI has audited over $1 billion PV-10 and 677 Bcfe in our possible reserve category as of December 31, 2013 for the redevelopment of these additional zones. Please see Reserves.

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Our well results have shown consistency in initial production, decline rates and estimated ultimate recovery. The consistency of these results gives us confidence that the full-scale redevelopment of the Terryville Complex that we began in 2013 will continue to be successful. The table below details certain information on estimated ultimate recoveries and production on a gross basis for our 41 existing horizontal wells currently producing from our four primary target zones in the Terryville Complex to the extent such data is available as of the dates and for the periods presented below. The wells below highlight the consistency of our drilling results in the four primary target zones in which we plan to focus our future development activity.

		Producing Wells					Gross Wellhead Flow Rates After Processing (MMcfe/d)(2)(3)				
Well Name	**Lateral Length (Feet)**	**EUR (Bcfe)(1)**	**EUR Bcfe/ 1,000**	**First Production**	**Days Producing**	**Cumulative Production (Bcfe)**	**0-30**	**0-90**	**91-180**	**181-360**	**D&C ($MM)**
Upper Red											
LD Barnett 23H-2	4,015	12.3	3.1	1/30/2012	975	5.0	14.5	12.0	7.7	5.6	6.7
Colquitt 20 17H-1	4,357	11.5	2.6	7/30/2012	793	4.3	17.5	12.6	7.2	5.1	7.8
Dowling 22 15H-1	5,376	9.4	1.8	9/22/2012	739	5.7	16.3	15.6	11.1	8.2	8.8
Nobles 13H-1	4,216	9.1	2.1	11/17/2012	683	4.6	21.5	16.7	9.9	6.5	7.8
Sidney McCullin 16 21H-1	4,604	13.8	3.0	1/19/2013	620	5.0	17.4	14.2	10.8	8.4	8.1
Wright 14 11 HC-1	5,250	11.9	2.3	5/27/2013	492	5.5	19.6	18.1	16.1	8.4	8.8
BF Fallin 22 15H-1	5,122	12.3	2.4	6/17/2013	471	3.9	14.8	13.7	11.8	5.9	7.5
Dowling 20 17H-1	4,327	9.0	2.1	7/22/2013	436	2.6	15.2	11.0	5.7	4.5	10.7
Gleason 31H-1	3,692	2.4	0.7	8/12/2013	415	0.6	2.9	2.3	1.6	1.2	9.5
Burnett 26H-1	2,405	5.5	2.3	9/22/2013	374	1.2	6.9	5.6	3.5	2.4	6.9
Drewett 17 8H-1	4,010	15.6	3.9	11/13/2013	322	3.9	22.1	18.6	11.9		7.7
Wright 13 12 HC-2	6,009	24.0	4.0	12/21/2013	284	4.6	22.7	19.6	16.3		8.5
LA Minerals 15 22H-2	5,814	17.3	3.0	1/21/2014	253	3.4	17.8	16.1	13.4		8.8
Wright 13 24 HC-3	6,606	20.9	3.2	4/14/2014	170	3.4	30.3	24.6			10.8
Wright 13 24 HC-1	6,678	15.5	2.3	4/14/2014	170	2.8	25.0	20.4			11.8
TL McCrary 14 11 HC-5	5,875	30.0	5.1	4/14/2014	170	3.0	22.9	23.3			10.2
LA Minerals 19 30 HC-2	6,912	15.1	2.2	5/29/2014	125	2.3	25.1	20.4			10.8
LA Minerals 19 30 HC-1	6,519	19.6	3.0	6/1/2014	122	2.0	21.5	17.7			11.6
Werner 29H-1	3,410	4.7	1.4	8/13/2014	49	0.4	8.6				11.0
Werner 29 32 5 HC-1	6,810	9.7	1.4	8/13/2014	49	0.8	18.4				10.4
Werner 29 32 5 HC-2	8,300	16.5	2.0	8/13/2014	49	1.2	26.1				12.2
Temple 8H-1	2,403	6.3	2.6	8/24/2014	38	0.4	12.7				9.6
Temple 8 17 HC-1	6,210	2.9	0.5	8/29/2014	33	0.3	8.4				11.9
TL McCrary 14 11 HC-2	4,401	NA	NA	9/25/2014	6	0.1					7.7
TL McCrary 14 11 HC-4	4,810	NA	NA	9/25/2014	6	0.0					9.0
Lower Red											
TL McCrary 14H-1	4,544	12.7	2.8	5/1/2012	883	4.5	14.4	11.7	8.3	5.4	7.7
Nobles 13H-2	4,060	5.6	1.4	11/17/2012	683	3.3	16.0	11.9	8.2	5.2	7.8
LA Methodist Orphanage 14H-1	3,637	9.5	2.6	2/15/2013	593	4.0	13.9	13.0	9.7	6.3	9.1
Dowling 21 16H-1	4,590	8.4	1.8	3/18/2013	562	3.0	13.0	10.1	6.5	4.5	6.6
Drewett 17 8H-2	3,700	4.2	1.1	11/13/2013	322	1.2	8.7	6.2	3.2		7.0
Wright 13 12 HC-1	5,409	9.4	1.7	12/21/2013	284	2.2	14.7	11.4	7.2		9.3
LA Minerals 15 22H-1	5,926	8.1	1.4	1/21/2014	253	1.9	13.8	10.9	6.4		7.8
Wright 13 24 HC-4	6,518	15.1	2.3	4/14/2014	170	2.6	25.7	19.6			13.4
LA Minerals 19 30 HC-3	5,356	2.5	0.5	5/29/2014	125	0.6	8.8	5.9			12.1
LA Minerals 19 30 HC-4	6,469	3.5	0.5	6/1/2014	122	0.9	13.6	8.5			13.8
TL McCrary 14 11 HC-1	4,010	NA	NA	9/25/2014	6	0.0					8.9
TL McCrary 14 11 HC-3	4,620	NA	NA	9/25/2014	6	0.0					8.3
Lower Deep Pink Zone											
LA Methodist Orphanage 14H-2	3,550	6.1	1.7	2/15/2013	593	3.5	14.2	11.6	7.6	5.7	6.1
Wright 13 12 HC-4	5,010	5.8	1.2	12/21/2013	284	1.6	11.8	8.8	4.8		7.0
Wright 13 12 HC-3	5,706	5.4	0.9	12/21/2013	284	1.6	12.5	9.3	5.0		7.4
Upper Deep Pink Zone											
Werner 29 32 5 HC-3	6,679	3.1	0.5	8/13/2014	49	0.3	7.2				10.1
Averages(4)											
All Wells	**5,071**	**10.7**	**2.1**		**319**	**2.4**	**16.1**	**13.6**	**8.4**	**5.6**	**9.2**
Upper Red	**5,125**	**12.8**	**2.5**		**314**	**2.7**	**17.7**	**15.7**	**9.8**	**5.6**	**9.4**

Lower Red	**4,903**	**7.9**	**1.6**	**334**	**2.0**	**14.3**	**10.9**	**7.1**	**5.4**	**9.3**
Lower Deep Pink	**4,755**	**5.8**	**1.3**	**387**	**2.2**	**12.8**	**9.9**	**5.8**	**5.7**	**6.8**
Upper Deep Pink	**6,679**	**3.1**	**0.5**	**49**	**0.3**	**7.2**				**10.1**

(1) EUR represents the Estimated Ultimate Recovery or sum of total gross remaining proved reserves attributable to each location in our recent reserve report and cumulative sales from such location. EUR is shown on a combined basis for oil/condensates, gas and NGLs after the effects of processing.
(2) Production data is as of September 30, 2014 and shown gross on a combined basis after the effects of processing.
(3) Periodic flow rates start on day 4, with days 1 through 3 used to allow clean up associated with well completion. The 30-day flow rates therefore start on day 4 and continue 30 days to day 33 and the 90-day flow rates go from day 4 to day 93.
(4) We also have five horizontal producing wells outside of the four primary target zones. These averages do not include such wells.

Cotton Valley Terryville Complex Proved Reserves Update

As of September 30, 2014, within the core Terryville Complex, we had proved reserves of 849 Bcfe based on our recent reserve report, and an aggregate drilling inventory of 1,411 gross identified drilling locations, taking into account drilling activity during the first nine months of 2014. The PV-10 of our proved reserves within the Terryville Complex as of September 30, 2014 was $1.6 billion. PV-10 is a non-GAAP financial measure and differs from standardized measure, the most directly comparable GAAP financial measure. Please see Reserves. SEC pricing for natural gas and oil used in calculating the PV-10 of such proved reserves as of September 30, 2014 was $4.23 per Mcf and $95.56 per Bbl, respectively, based on the unweighted average of the first-day-of-the-month prices for each of the twelve months preceding September 2014.

East Texas

We own and operate approximately 54,337 gross (42,894 net) acres as of December 31, 2013 in Texas, where we are currently producing primarily from the Cotton Valley, Travis Peak and Bossier formations and targeting the Cotton Valley formation for future development. From January 1, 2011 through December 31, 2013, we have drilled and completed 28 gross (10.3 net) wells and are operating one rig in East Texas as of December 31, 2013. In 2014, we plan to invest $29 million to drill 4 gross (4 net) wells in East Texas in the Joaquin Field of Panola and Shelby Counties. As of December 31, 2013, we had approximately 108 gross identified horizontal drilling locations in East Texas, including 54 gross (43 net) drilling locations to which we have attributed proved undeveloped reserves as of December 31, 2013. For the nine months ended September 30, 2014, our average net daily production from our East Texas properties was 27 MMcfe/d, of which 75% was natural gas. Within our East Texas properties, on a proved reserves basis, we operate approximately 94% of our existing properties.

Rockies

We own approximately 162,375 gross (66,191 net) acres as of December 31, 2013 in our Rockies region and for the nine months ended September 30, 2014 our average net daily production from this region was 6 MMcfe/d. In 2014, we plan to invest $18 million to complete 2 gross (2 net) vertical wells in the Tepee Field of the Piceance Basin targeting the Mancos and Williams Fork formations. As of December 31, 2013, we had approximately 174 gross identified vertical drilling locations in the Tepee Field in our Rockies properties.

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Reserves

Our estimates of proved reserves are prepared by NSAI, and our estimates of probable and possible reserves are prepared by our management and audited by NSAI. As of December 31, 2013, we had 1,126 Bcfe, 800 Bcfe and 1,711 Bcfe of estimated proved, probable and possible reserves, respectively. As of this date, our proved reserves were 71% gas and 29% NGLs and oil. Additionally, the PV-10 of our proved reserves was $1,469 million, the PV-10 for our probable reserves was $1,052 million and the PV-10 for our possible reserves was $2,386 million. The following table provides summary information regarding our estimated proved, probable and possible reserves data by area based on our reserve report as of December 31, 2013 and our average net daily production by area for the nine months ended September 30, 2014:

	Proved Total (Bcfe)	% Gas	% Developed	Proved PV-10 (in millions)(1)	Probable Total (Bcfe)(2)	Probable PV-10 (in millions)(1)	Possible Total (Bcfe)(2)	Possible PV-10 (in millions)(1)	Average Net Daily Production (MMcfe/d)
Terryville Complex	945	71%	33%	$ 1,341	688	$ 1,032	1,643	$ 2,383	175
East Texas	175	75%	29%	110	109	18	66	3	27
Rockies	6	49%	100%	18	2	2	2	1	6
Total	1,126	71%	33%	$ 1,469	800	$ 1,052	1,711	$ 2,386	208

(1) In this prospectus, we have disclosed our PV-10 based on our reserve report. PV-10 is a non-GAAP financial measure and represents the period-end present value of estimated future cash inflows from our natural gas and crude oil reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash flows and using SEC pricing assumptions in effect at the end of the period. SEC pricing for natural gas and oil of $3.67 per Mcf and $93.42 per Bbl was based on the unweighted average of the first-day-of-the-month prices for each of the twelve months preceding December 2013. PV-10 differs from standardized measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes. Moreover, GAAP does not provide a measure of estimated future net cash flows for reserves other than proved reserves. Because PV-10 estimates of probable and possible reserves are more uncertain than PV-10 and standardized estimates of proved reserves, but have not been adjusted for risk due to that uncertainty, they may not be comparable with each other. Nonetheless, we believe that PV-10 estimates for reserve categories other than proved present useful information for investors about the future net cash flows of our reserves in the absence of a comparable GAAP measure such as standardized measure. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. In addition, investors should be cautioned that estimates of PV-10 for probable and possible reserves, as well as the underlying volumetric estimates, are inherently more uncertain of being recovered and realized than comparable measures for proved reserves, and that the uncertainty for possible reserves is even more significant. Our PV-10 estimates of proved reserves and our standardized measure are equivalent as of December 31, 2013 because, prior to the completion of our initial public offering, we were not subject to entity level taxation. Accordingly, no provision for federal income taxes has been provided because taxable income for 2013 was passed through to our equity holders. However, had we not been a tax exempt entity as of December 31, 2013, our estimated discounted future income tax in respect of our proved, probable and possible reserves would have been approximately $401 million, $368 million and $835 million, respectively. Since the closing of our initial public offering, we are treated as a taxable entity for federal income tax purposes and our future income taxes will be dependent upon our future taxable income. Neither PV-10 nor standardized measure represents an estimate of fair market value of our natural gas and oil properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of estimated reserves held by companies without regard to the specific tax characteristics of such entities.

(2) Substantially all of our estimated probable and possible reserves are classified as undeveloped.

Drilling Inventory and Capital Budget

We intend to develop our multi-year drilling inventory by utilizing our significant expertise in horizontal drilling and fracture stimulation to grow our production, reserves and cash flow. For 2014, we have budgeted a total of $351 million to drill 39 gross (34 net) operated horizontal wells. We expect to fund our 2014 development primarily from cash flows from operations. The majority of our drilling locations and our 2014 development program are focused on the Terryville Complex, where we plan to invest $304 million on drilling 33 gross (29 net) horizontal wells and 3 gross (2.7 net) vertical wells. In East Texas, we plan to invest $29 million on drilling and completing 4 gross (4 net) horizontal wells. In the Rockies, we plan to invest $18 million on completing 2 gross (2 net) vertical wells in the Tepee Field.

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The following table provides information regarding our acreage and drilling locations by area as of December 31, 2013:

	Net Acreage	WI%	Gross Horizontal Drilling Locations(1)(2)(3) Proved	Probable	Possible	Management	Total Gross	Total Net	Gross Horizontal Drilling Inventory (years)
Terryville Complex	96,733	74%	91	147	450	743	1,431	994	43
East Texas	42,894	79%	54	39	15		108	92	27
Rockies	66,191	41%		23	20		43	4	
Total	205,818	59%	145	209	485	743	1,582	1,091	42

(1) The above table excludes 192 proved vertical drilling locations in our reserve report in the Terryville Complex and 174 identified vertical locations based on management estimates in the Rockies.
(2) Please see Business Our Operations Drilling Locations for more information regarding the process and criteria through which these drilling locations were identified. The drilling locations on which we actually drill will depend on the availability of capital, regulatory approval, commodity prices, costs, actual drilling results and other factors. Please see Risk Factors Risks Related to Our Business 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. Proved, probable and possible locations are based on our reserve report. Management locations are based on management estimates of additional identified drilling locations.
(3) As of September 30, 2014, we had an aggregate drilling inventory of 1,411 identified gross horizontal inventory locations in the Terryville Complex, taking into account drilling activity during the first nine months of 2014. Please see Our Properties Cotton Valley Terryville Complex Proved Reserves Update.

Our extensive inventory and horizontal drilling program in the Terryville Complex is currently focused on four zones within the Cotton Valley formation the Upper Red, Lower Red, Lower Deep Pink and Upper Deep Pink. The table below sets forth our drilling locations by zone as of December 31, 2013 along with the average results for the wells we have drilled within each zone. Please see Business Our Properties Cotton Valley Terryville Complex Horizontal Redevelopment for more detail on our properties in the Terryville Complex and the table on page 99 for the 30 day initial production rate and EUR condensate volumes.

Lower Cotton Valley Zone	Gross Horizontal Drilling Locations(1)(4) Proved	Probable	Possible	Management	Total	Average Historical Results(2) Producing Wells Drilled(1)	EUR (Bcfe)(3)	Drilling and Completion Costs ($MM)
Upper Red	47	42	40	313	442	25	12.8	$ 9.4
Lower Red	40	40	36	276	392	12	7.9	9.3
Lower Deep Pink	4	28	47	79	158	3	5.8	6.8
Upper Deep Pink		37	42	75	154	1	3.1	10.1
Other Zones			285		285			
Total Terryville Complex	91	147	450	743	1,431	41	10.7	$ 9.2

(1) Please see Business Our Operations Drilling Locations for more information regarding the process and criteria through which these drilling locations were identified. The drilling locations on which we actually drill will depend on the availability of capital, regulatory approval, commodity prices, costs, actual drilling results and other factors. Please see Risk Factors Risks Related to Our Business 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. Proved, probable and possible locations are based on our reserve report. Management locations are based on management estimates of additional identified drilling locations.
(2) Relates to the 41 horizontal wells drilled by us in the four primary target zones in the Terryville Complex and included in our recent reserve report as proved developed reserves as of September 30, 2014.
(3) EUR represents the Estimated Ultimate Recovery or the sum of total gross remaining proved reserves attributable to each location in our recent reserve report and cumulative sales from such location. EUR is shown at the wellhead on a combined basis for oil/condensates and wet gas.
(4)

As of September 30, 2014, we had an aggregate drilling inventory of 1,411 identified gross horizontal inventory locations in the Terryville Complex, taking into account drilling activity during the first nine months of 2014. Please see Our Properties Cotton Valley Terryville Complex Proved Reserves Update.

Our Terryville horizontal development program in 2014 has an average working interest of 86% and our total horizontal development inventory has an average working interest of 69%.

For the Terryville Complex, our 2014 budget assumes an average drilling and completion cost of $9.5 million for gross horizontal wells ($8.3 million per net well) and is based on an average lateral length of 5,824 feet. As part of our long-term development plan, the lateral length of our planned wells is expected to increase and we expect wells within the Terryville Complex to increase to a 7,500 foot lateral length.

Business Strategies

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

Grow production, reserves and cash flow through the development of our extensive drilling inventory. We believe our extensive inventory of low-risk drilling locations, combined with our operating expertise, will enable us to continue to deliver production, reserve and cash flow growth and create shareholder value. As of December 31, 2013, we had assembled an aggregate drilling inventory of 1,582 gross identified horizontal drilling locations, 90% of which are in the Terryville Complex, representing a drilling inventory of over 43 years based on our expected 2014 drilling program. 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. Since initiating our horizontal drilling program with one rig in 2011, we have invested over $521 million in the Terryville Complex through September 30, 2014. With six rigs running in the Terryville Complex as of September 30, 2014, we are one of the most active drillers in the Cotton Valley formation. We intend to dedicate approximately $304 million of our $351 million drilling and completion budget in 2014 to develop the overpressured liquids-rich Terryville Complex through multi-well pad drilling. 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. We also believe our East Texas region has a significant inventory of low-risk, liquids-rich horizontal drilling locations. Finally, we continue to evaluate our leasehold positions in the Rockies and have preliminarily identified over 170 potential vertical locations.

Maintain a disciplined, growth oriented financial strategy. We intend to fund our growth primarily with internally generated cash flows 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 liquidity to fund our drilling program.

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Since approximately 76% of our acreage in the Terryville Complex was held by production as of December 31, 2013 and no significant drilling commitments are needed to hold our remaining acreage in the near term, we are able to allocate capital among projects in a manner that optimizes both costs and returns, resulting in a highly efficient drilling program.

Make opportunistic acquisitions that meet our strategic and financial objectives. We will seek to acquire oil and gas properties that we believe complement our existing properties in our core areas of operation. In addition to our focus on the Terryville Complex, we are pursuing 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, amassing a land position as of December 31, 2013 of 96,733 net acres, 51,522 net acres of which we believe to be in the core of the play. 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, 2013, we owned approximately 60,041 gross (51,522 net) acres in what we believe to be the core of the Terryville Complex in Lincoln Parish, which we believe to be one of North America s most prolific liquids-rich natural gas fields, characterized by consistent and predictable geology and multiple stacked pay formations confirmed by extensive vertical well control. Through September 30, 2014, our drilling program in the Terryville Complex has produced some of the top performing gas wells in the United States in the previous two years, with single horizontal well results having achieved EURs averaging 10.7 Bcfe per well. Through September 30, 2014, we have brought 41 wells online within our four primary target zones with average 30-day initial production rates of 16.1 MMcfe/d and average drilling and completion costs of $9.2 million per well. Approximately 76% of our acreage in the Terryville Complex was held by production at December 31, 2013 and there are no significant lease expirations until 2017. Additionally, all of our acreage in this play can be held by running a one-rig program over the next 18 months.

De-risked acreage position with multi-year inventory of liquids-rich drilling opportunities. As of December 31, 2013, we had a drilling inventory consisting of 1,582 gross identified horizontal drilling locations, of which approximately 145 are gross proved undeveloped locations. Based on our expected 2014 drilling program and gross identified drilling locations, we have over 42 years of liquids-rich drilling inventory. The majority of our drilling activity has been and will continue to be focused in the Terryville Complex, where we produce liquids-rich natural gas from the overpressured Cotton Valley formation. We have used subsurface data from our vertical wells coupled with 3-D seismic data to identify and prioritize our inventory based on returns. This liquids-rich gas formation allows for NGL processing that, when coupled with the condensate produced, results in strong well economics. For the nine months ended September 30, 2014, 56% of our MRD Segment revenues were attributable to natural gas, 22% to NGLs and 22% to oil.

Significant operational control with low cost operations. On a proved reserves basis, we operate 99% of our properties and have operational control of all of our drilling inventory in the Terryville Complex. We believe maintaining operational control will enable us to enhance returns by implementing more efficient and cost-effective operating practices, through the selection of economic drilling locations, opportunistic timing of development, continuous improvement of drilling, completion and stimulation techniques and development on multi-well pads. As a result of the contiguous nature of our leasehold in the Terryville Complex, its geologic continuity and cross unit lateral pooling, we are able to drill consistently long laterals, averaging over 5,071

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lateral feet, which helps us to reduce costs on a per-lateral foot basis and increase our returns. We expect the average lateral length of the 33 gross wells that we expect to drill in the Terryville Complex in 2014 to be 5,824 feet per well. Operating in mature basins in North Louisiana and East Texas 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 MRD Segment lease operating costs declining 35% from $0.50 per Mcfe for the nine months ended September 30, 2013 to $0.33 per Mcfe for the nine months ended September 30, 2014.

Proven and incentivized executive and technical team. We believe our management and technical teams are one of our principal competitive strengths due to our team s significant industry experience and long history of working together in the identification, execution and integration of acquisitions, cost efficient management of profitable, large scale drilling programs and a focus on rates of return. Additionally, our technical team has substantial expertise in advanced drilling and completion technologies and decades of expertise in operating in the North Louisiana and East Texas regions. The members of our management team collectively have an average of 22 years of experience in the oil and natural gas industry. John A. Weinzierl, our Chief Executive Officer, has 24 years of oil and natural gas industry experience as a petroleum engineer, a strong commercial and technical background and extensive experience acquiring and managing oil and natural gas properties. Our management team has a significant economic interest in us directly and through its equity interests in our controlling stockholder, MRD Holdco. We believe our management team is motivated to deliver high returns, create shareholder value and maintain safe and reliable operations.

Our relationship with MEMP. We own a 0.1% general partner interest in MEMP through our ownership of its general partner as well as 50% of MEMP s incentive distribution rights. MEMP s objective as a master limited partnership is to generate stable cash flows, allowing it to make quarterly distributions to its limited partners and, over time, to increase those quarterly distributions. As a result of its familiarity with our management team and our asset base and our track record of prior drop-down transactions, we believe that MEMP is a natural purchaser of properties from us that meet its acquisition criteria. We believe this mutually beneficial relationship enhances MEMP s ability to generate consistent returns on its oil and natural gas properties, provides us with a growing source of cash flow from our partnership interests in MEMP and allows us to monetize producing non-core properties. Since MEMP s initial public offering, we have consummated drop-down transactions with MEMP totaling approximately $391 million. In addition, we may have the opportunity to work jointly with MEMP to pursue certain acquisitions of oil and natural gas properties that may not otherwise be attractive acquisition candidates for either of us individually. While we believe that MEMP would be a preferred acquirer of our mature, non-core assets, we are under no obligation to offer to sell, and it is under no obligation to offer to buy, any of our properties.

Financial strength and flexibility. During 2013, we generated $159 million of pro forma MRD Segment Adjusted EBITDA and made pro forma total capital expenditures of $203 million. During the nine months ended September 30, 2014, we generated pro forma MRD Segment Adjusted EBITDA of $259 million and made pro forma capital expenditures of $268 million. We intend to continue to fund our organic growth predominantly with internally generated cash flows 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 three-to-five year rolling hedge program. As of September 30, 2014, our total liquidity, consisting of cash on hand and available borrowing capacity under our revolving credit facility, was approximately $650.2 million.

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Initial Public Offering and Recent Developments

On June 18, 2014, we completed our initial public offering of 49,220,000 shares of common stock at a price to the public of $19.00 per share. Of the 49,220,000 shares offered, 21,500,000 were offered by us and 27,720,000 were offered by the selling stockholder, MRD Holdco. We did not receive any proceeds from the sale of shares by MRD Holdco. We used the net proceeds of approximately $380.2 million from our sale of shares in our initial public offering (i) to redeem the 10.00%/10.75% Senior PIK toggle notes due 2018 (the PIK notes) issued by MRD LLC in their entirety and to pay the applicable premium in connection with such redemption and accrued and unpaid interest to the date of redemption, (ii) together with borrowings of approximately $614.5 million under our $2.0 billion revolving credit facility entered into in connection with the closing of our initial public offering, to make a cash payment to certain former management members of WildHorse Resources in connection with their contribution to us of their membership interests and incentive units in WildHorse Resources, (iii) to repay borrowings outstanding under WildHorse Resources revolving credit facility and second lien term loan, which we refer to collectively as WildHorse Resources credit agreements, (iv) to reimburse MRD LLC for interest paid on the PIK notes and (v) to pay costs associated with our revolving credit facility.

On July 10, 2014, we completed a private placement of $600.0 million aggregate principal amount of 5.875% senior unsecured notes (the MRD Senior Notes) at par. The MRD Senior Notes will mature on July 1, 2022. Interest on the MRD Senior Notes accrues from July 10, 2014 and will be payable semiannually on January 1 and July 1 of each year, commencing on January 1, 2015. The net proceeds of approximately $586.0 million, after deducting the initial purchasers discounts and commissions and offering expenses, were used to repay a portion of the borrowings outstanding under our revolving credit facility. The amounts to be repaid under our revolving credit facility were incurred to repay the amounts outstanding under WildHorse Resources credit facilities in connection with the closing of our initial public offering. In conjunction with the closing of the offer and sale of the MRD Senior Notes, the borrowing base under our revolving credit facility was automatically decreased by $56.5 million.

On November 4, 2014, our wholly-owned subsidiary, Terryville Mineral & Royalty Partners LP (TRVL), filed a registration statement on Form S-1 with the SEC in connection with its proposed initial public offering of common units representing limited partner interests. In connection with the closing of the proposed offering, we will contribute to TRVL certain overriding royalty interests in approximately 27,000 gross acres in the Terryville Complex in exchange for limited partner interests in TRVL. The royalty interests will entitle TRVL to receive 7% of gross revenues from production within such acreage on all of our existing horizontal producing wells and future wells completed by us. TRVL intends to distribute the net proceeds from the proposed offering to us. A registration statement relating to these securities has been filed with the SEC but has not yet become effective. These securities may not be sold nor may any offers to buy be accepted prior to the time the registration statement becomes effective, and this prospectus does not constitute an offer to sell or a solicitation of any offers to buy these securities.

Acquisition History

We built out our leasehold positions in North Louisiana, East Texas and the Rocky Mountains primarily through the following acquisition activities:

In November 2007, we acquired interests in the Joaquin Field, which is the core of our East Texas acreage;

In December 2007, we acquired interests in the Tepee Field in the Piceance Basin in Colorado;

In April and May 2010, we acquired interests in the Terryville Complex and other North Louisiana fields, which are the core of our North Louisiana acreage;

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In November 2010, we acquired interests in the Spider and E. Logansport Fields in North Louisiana;

In May 2012, we acquired interests in the Terryville Complex and Double A Field in North Louisiana and East Texas;

In April 2013, we acquired interests in the West Simsboro and Simsboro Fields of the Terryville Complex in North Louisiana;

In November 2013, we acquired the remaining equity interests in Classic Hydrocarbons Holdings, L.P., Classic Hydrocarbons GP Co., L.L.C. and Black Diamond Minerals, LLC, which hold oil and natural gas properties in East Texas, North Louisiana and the Rocky Mountains; and

In February 2014, we repurchased net profits interests in the Terryville Complex from an affiliate of NGP for $63.4 million after customary adjustments. These net profits interests were originally sold to the NGP affiliate upon the completion of certain acquisitions in 2010 by WildHorse Resources.

Our Principal Stockholder

Our principal stockholder is MRD Holdco, which is controlled by the Funds, which are three of the private equity funds managed by NGP. Upon completion of this offering, MRD Holdco, one of the selling stockholders in this offering, will own approximately 40% of our common stock (or approximately 38% if the underwriters option to purchase additional shares from the selling stockholders is exercised in full). Pursuant to a voting agreement, MRD Holdco also has the right to direct the vote of an additional approximately 18% of our common stock (or approximately 18% if the underwriters option to purchase additional shares from the selling stockholders is exercised in full) owned by certain former management members of WildHorse Resources (including the other selling stockholders). The Funds also collectively indirectly own 50% of MEMP s incentive distribution rights, and MRD Holdco owns 5,360,912 subordinated units of MEMP, representing an approximate 6.2% limited partner interest in MEMP. We are also a party to certain other agreements with MRD Holdco, the Funds and certain of their affiliates. For a description of the voting agreement and these other agreements, please read Certain Relationships and Related Party Transactions.

Founded in 1988, NGP is a family of private equity investment funds, with cumulative committed capital of over $14.5 billion since inception, 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, which together with its affiliates has managed over $17 billion in cumulative committed capital since inception.

Our Interest in Memorial Production Partners LP

Through our ownership of its general partner, we control MEMP. We also own 50% of its incentive distribution rights. MEMP is a publicly traded limited partnership 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 East Texas/North Louisiana, the Rockies, South Texas, the Permian 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. Because we control MEMP, we are required to consolidate MEMP for accounting and financial reporting purposes, even though we and MEMP have independent capital structures.

During the year ended December 31, 2013 and nine months ended September 30, 2014, less than $0.1 million and $0.1 million of distributions, respectively, were made in respect of the MEMP incentive distribution rights. Please see Business Relationship with Memorial Production Partners LP for further information on our interest in MEMP.

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Risk Factors

Investing in our common stock involves risks that include the speculative nature of oil and natural gas exploration, competition, volatile commodity prices and other material factors. For a discussion of these risks and other considerations that could negatively affect us, including risks related to this offering and our common stock, please read Risk Factors beginning on page 23 of this prospectus and Cautionary Note Regarding Forward-Looking Statements.

Corporate History and Structure

We are a Delaware corporation formed by MRD LLC in January 2014 engaged in the acquisition, exploitation, and development of natural gas, NGL and oil properties primarily in North Louisiana and East Texas. MRD LLC was a Delaware limited liability company formed on April 27, 2011 by the Funds to own, acquire, exploit and develop oil and natural gas properties.

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): (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 MEMP GP, which owns a 0.1% general partner interest and 50% of the incentive distribution rights in MEMP, and (2) its 99.9% membership interest in WildHorse Resources. In addition, certain former management members of WildHorse Resources contributed to us the remaining 0.1% membership interest in WildHorse Resources, and also exchanged their incentive units in WildHorse Resources, for shares of our common stock and cash consideration. As a result, we are majority-owned by the group consisting of MRD Holdco and certain former management members of WildHorse Resources.

Following the completion of our initial public offering, MRD LLC distributed to MRD Holdco (i) its interests in BlueStone, MRD Royalty LLC, MRD Midstream, Golden Energy Partners LLC (Golden Energy) and Classic Pipeline; (ii) the MEMP subordinated units; (iii) the remaining cash released from its debt service reserve account in connection with the redemption of the PIK notes; and (iv) approximately $6.7 million of cash received by MRD LLC in connection with the sale of Golden Energy s assets in May 2014. We 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, and MRD LLC was merged into MRD Operating upon the termination of the PIK notes indenture on June 27, 2014.

For more information regarding BlueStone, see Management s Discussion and Analysis of Financial Condition and Results of Operations Results of Operations MRD Segment. For more information about the services agreement with WildHorse Resources, see Certain Relationships and Related Party Transactions Services Agreement.

The following diagram shows our ownership structure after giving effect to this offering, assuming no exercise of the underwriters option to purchase additional shares from the selling stockholders, and does not give effect to 19,250,000 shares of common stock reserved for future issuance under the Memorial Resource Development Corp. 2014 Long Term Incentive Plan (described in Management 2014 Long Term Incentive Plan). See Principal and Selling Stockholders for the number of shares being offered by MRD Holdco and the other selling stockholders, respectively.

(1) If the underwriters exercise in full their option to purchase additional shares of common stock from the selling stockholders, the ownership interest of the public stockholders will increase to 84,779,211 shares of common stock, representing an aggregate 44% ownership interest in us, MRD Holdco will own 74,269,433 shares of common stock, representing an aggregate 38% ownership interest in us and certain former management members of WildHorse Resources will own 34,510,567 shares of common stock, representing an aggregate 18% ownership interest in us.

(2) As of October 31, 2014.

(3) The Funds refer 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. Please read Principal and Selling Stockholders for information regarding beneficial ownership. The Funds collectively indirectly own 50% of the Partnership s incentive distribution rights.

(4) Subsidiaries of MRD Holdco include BlueStone, MRD Royalty, MRD Midstream, Golden Energy and Classic Pipeline. Also, please see the Principal and Selling Stockholders table on page 148 for the beneficial ownership of our shares by our executive officers and directors.

(5) Includes Classic, Classic GP and Beta Operating.

Corporate Information

Our principal executive offices are located at 500 Dallas St., Suite 1800, Houston, Texas 77002, and our phone number is (713) 588-8300. Our website address is www.memorialrd.com. We make our periodic reports and other information filed with or furnished to the Securities and Exchange Commission, which we refer to as

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the SEC, available free of charge through our website as soon as reasonably practicable after those reports and other information are electronically filed with or furnished to the SEC. Information on our website or any other website is not incorporated by reference into, and does not constitute a part of, this prospectus.

Emerging Growth Company Status

We are an emerging growth company as defined in the Jumpstart Our Business Startups Act (the JOBS Act). For as long as we are an emerging growth company, unlike other public companies that are not emerging growth companies, we are not required to:

- provide an auditor s attestation report on management s assessment of the effectiveness of our system of internal control over financial reporting pursuant to Section 404 of the Sarbanes-Oxley Act of 2002;
- provide more than two years of audited financial statements and related management s discussion and analysis of financial condition and results of operations;
- comply with any new requirements adopted by the Public Company Accounting Oversight Board, or the PCAOB, requiring mandatory audit firm rotation or a supplement to the auditor s report in which the auditor would be required to provide additional information about the audit and the financial statements of the issuer;
- provide certain disclosure regarding executive compensation required of larger public companies or hold shareholder advisory votes on executive compensation required by the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act); or
- obtain shareholder approval of any golden parachute payments not previously approved.

We will cease to be an emerging growth company upon the earliest of:

- the last day of the fiscal year in which we have $1.0 billion or more in annual revenues;
- the date on which we become a large accelerated filer (the fiscal year-end on which the total market value of our common equity securities held by non-affiliates is $700 million or more as of June 30);
- the date on which we issue more than $1.0 billion of non-convertible debt over a three-year period; or
- the last day of the fiscal year following the fifth anniversary of our initial public offering.

In addition, Section 107 of the JOBS Act provides that an emerging growth company can take advantage of the extended transition period provided in Section 7(a)(2)(B) of the Securities Act of 1933, as amended, or the Securities Act, for complying with new or revised accounting standards, but we have irrevocably opted out of the extended transition period and, as a result, we will adopt new or revised accounting standards on the relevant dates in which adoption of such standards is required for other public companies.

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The Offering

Selling Stockholders	MRD Holdco and certain former management members of WildHorse Resources.
Common stock offered by the selling stockholders	30,000,000 shares (or 34,500,000 shares, if the underwriters exercise in full their option to purchase additional shares).
Common stock to be outstanding immediately after the offering	193,559,211 shares. The number of shares of common stock outstanding will not change as a result of this offering.
Option to purchase additional shares	The selling stockholders have granted the underwriters a 30-day option to purchase up to an aggregate of 4,500,000 additional shares of our common stock held by the selling stockholders.
Common stock voting rights	Each share of our common stock entitles its holder to one vote.
Use of proceeds	We will not receive any of the proceeds from the sale of shares of our common stock by the selling stockholders, including pursuant to any exercise by the underwriters of their option to purchase additional shares of our common stock. The selling stockholders may be deemed under federal securities laws to be underwriters with respect to the common stock they may sell in connection with this offering.
Dividend policy	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 of directors (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. See Dividend Policy.
Risk factors	You should carefully read and consider the information set forth under Risk Factors beginning on page 23 of this prospectus and all other information set forth in this prospectus before deciding to invest in our common stock.
Listing and trading symbol	Our common stock is listed on the NASDAQ Global Select Market (NASDAQ) under the trading symbol MRD.

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Summary Historical Consolidated and Combined Pro Forma Financial Data

Prior to the restructuring transactions and the closing of our initial public offering, MRD LLC and its consolidated subsidiaries, our accounting predecessor, controlled MEMP through its ownership of MEMP GP, the general partner of MEMP. Because MRD LLC controlled MEMP through its ownership of the general partner, MRD LLC was required to consolidate MEMP for accounting and financial reporting purposes even though MRD LLC owned a minority of its partner interests and MRD LLC and MEMP had independent capital structures. MRD LLC received cash distributions from MEMP as a result of its partner interests and incentive distribution rights in MEMP, when declared and paid by MEMP. In connection with the closing of our initial public offering, MRD LLC contributed substantially all of its existing assets to us in exchange for shares of our common stock. Through our ownership of MEMP GP, we continue to control MEMP and therefore will continue to consolidate the results of MEMP into our consolidated financial statements in future periods.

Our predecessor had two reportable business segments, both of which were engaged in the acquisition, exploitation, development and production of oil and natural gas properties:

MRD reflected all of MRD LLC s consolidating subsidiaries except for MEMP and its subsidiaries.

MEMP reflected the consolidated and combined operations of MEMP and its subsidiaries.

We continue to have two reportable segments. For more information regarding reportable business segments, please see the predecessor s audited historical financial statements and related notes and our unaudited historical interim financial statements included elsewhere in this prospectus.

The following tables include summary historical financial data for us and our predecessor, as well as the MRD Segment as of and for the periods indicated. The summary historical financial data of our predecessor as of and for the years ended December 31, 2013 and 2012 were derived from the audited historical financial statements of our predecessor included elsewhere in this prospectus. The summary historical financial data as of September 30, 2014 and for the nine months ended September 30, 2014 and 2013 were derived from our unaudited interim financial statements included elsewhere in this prospectus. The summary historical financial data of the MRD Segment as of and for the years ended December 31, 2013 and 2012 were derived from certain financial information used in the preparation of our predecessor s audited financial statements. The summary historical financial data for the MRD Segment as of September 30, 2014 and for the nine months ended September 30, 2014 and 2013 were derived from certain financial information used in the preparation of our unaudited interim financial statements.

The summary unaudited pro forma data for the nine months ended September 30, 2014 and for the year ended December 31, 2013 has been prepared to give pro forma effect to: (i) the exclusion of both BlueStone and Classic Pipeline as well as the MEMP subordinated units, none of which were conveyed to us in connection with our initial public offering; (ii) certain restructuring transactions that took place in connection with our initial public offering; (iii) the MEMP Wyoming Acquisition and the MEMP Offerings; (iv) our private placement on July 10, 2014 of $600.0 million aggregate principal amount of 5.875% senior unsecured notes at par as well as MEMP s private placement on July 17, 2014 of $500.0 million aggregate principal amount of 6.875% senior unsecured notes at 98.485% of par (collectively referred to as the Debt Offerings); and (v) incremental federal income tax expense.

We derived the data in the following tables from, and the following tables should be read together with and is qualified in its entirety by reference to, our historical financial statements (including those of our predecessor) and our pro forma financial statements and the accompanying notes included elsewhere in this prospectus. You should also read Management s Discussion and Analysis of Financial Condition and Results of Operations, and our pro forma and historical consolidated financial statements, all included elsewhere in this prospectus. Among

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other things, those historical consolidated and combined financial statements and pro forma financial statements include more detailed information regarding the basis of presentation for the following data.

	Year Ended December 31,		Nine Months Ended September 30,		Memorial Resource Development Corp. Pro Forma	
	2013	2012	2014	2013	Year Ended December 31, 2013	Nine Months Ended September 30, 2014
	(Predecessor)			(Predecessor)		
			(unaudited)		(unaudited)	
			(in thousands)			
Statement of Operations Data:						
Revenues:						
Oil and natural gas sales	$ 571,948	$ 393,631	$ 669,301	$ 420,857	$ 740,221	$ 758,811
Other revenues	3,075	3,237	3,584	1,884	2,268	3,034
Total revenues	575,023	396,868	672,885	422,741	742,489	761,845
Costs and expenses:						
Lease operating	113,640	103,754	111,887	81,746	165,092	136,561
Pipeline operating	1,835	2,114	1,596	1,343	1,835	1,596
Exploration	2,356	9,800	1,465	2,265	2,356	1,465
Production and ad valorem taxes	27,146	23,624	33,623	23,478	53,079	45,515
Depreciation, depletion and amortization	184,717	138,672	215,906	132,328	233,244	244,357
Impairment of proved oil and gas properties	6,600	28,871	67,181	21	4,201	67,181
Incentive unit compensation expense			969,390	19,069		968,367
General and administrative	125,358	69,187	61,061	55,982	101,098	61,045
Accretion of asset retirement obligations	5,581	5,009	4,601	4,016	5,803	4,741
(Gain) loss on commodity derivatives	(29,294)	(34,905)	11,580	(29,556)	(29,311)	11,580
(Gain) loss on sale of property	(85,621)	(9,761)	3,057	(86,218)	3,927	3,167
Other, net	649	502	(12)	622	649	(12)
Total costs and expenses	352,967	336,867	1,481,335	205,096	541,973	1,545,563
Operating income (loss)	222,056	60,001	(808,450)	217,645	200,516	(783,718)
Other income (expense)						
Interest expense, net	(69,250)	(33,238)	(104,928)	(41,994)	(117,843)	(108,998)
Loss on extinguishment of debt			(37,248)			(37,248)
Amortization of investment premium		(194)				
Other, net	145	535	102	81	143	102
Total other income (expense)	(69,105)	(32,897)	(142,074)	(41,913)	(117,700)	(146,144)
Income tax benefit (expense)	(1,619)	(107)	(14,398)	(1,432)	(29,814)	(21,836)
Net income (loss)	$ 151,332	$ 26,997	$ (964,922)	$ 174,300	$ 53,002	$ (951,698)
Cash Flow Data:						
Net cash provided by operating activities	$ 277,823	$ 240,404	$ 365,460	$ 237,176		
Net cash used in investing activities	367,443	606,738	1,496,677	235,883		
Net cash provided by financing activities	117,950	361,761	1,063,812	32,261		
Balance Sheet Data (at period end):						
Working capital (deficit)	$ 48,256	$ 63,054	$ (71,531)			
Total assets	2,829,161	2,459,304	4,021,667			
Total debt	1,663,217	939,382	2,111,800			
Total equity (including noncontrolling interests)	858,132	1,276,709	1,458,999			

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	MRD Segment				MRD Segment Pro Forma	
	Year Ended December 31,		Nine Months Ended September 30,		Year Ended December 31,	Nine Months Ended September 30,
	2013	2012	2014	2013	2013	2014
			(unaudited)		(unaudited)	
			(in thousands)			
Statement of Operations Data:						
Revenues:						
Oil and natural gas sales	$ 230,751	$ 138,032	$ 300,931	$ 171,013	$ 212,603	$ 299,242
Other revenues	807	782	561	348		11
Total revenues	231,558	138,814	301,492	171,361	212,603	299,253
Costs and expenses:						
Lease operating	25,006	24,438	18,657	17,065	23,354	18,723
Exploration	1,226	7,337	1,213	1,137	1,226	1,213
Production and ad valorem taxes	9,362	7,576	10,494	8,563	8,485	10,443
Depreciation, depletion and amortization	87,043	62,636	107,496	62,605	76,524	106,753
Impairment of proved oil and gas properties	2,527	18,339			128	
Incentive unit compensation expense			969,390	19,069		968,367
General and administrative	81,758	38,414	29,301	22,466	57,498	29,285
Accretion of asset retirement obligations	728	632	495	547	670	495
(Gain) loss on commodity derivatives	(3,013)	(13,488)	(17,130)	(8,361)	(3,030)	(17,130)
(Gain) loss on sale of property	(82,773)	(2)	3,057	(83,370)	6,775	3,167
Other, net	2	364		(25)	2	
Total costs and expenses	121,866	146,246	1,122,973	39,696	171,632	1,121,316
Operating income (loss)	109,692	(7,432)	(821,481)	131,665	40,971	(822,063)
Other income (expense)						
Interest expense, net	(27,349)	(12,802)	(44,355)	(15,947)	(45,972)	(32,151)
Loss on extinguishment of debt			(37,248)			(37,248)
Earnings from equity investments	1,066	4,880	(12,844)	(24)	269	18
Other, net	145	535	102	81	143	102
Total other income (expense)	(26,138)	(7,387)	(94,345)	(15,890)	(45,560)	(69,279)
Income tax (expense) benefit	(1,311)	178	(14,323)	(1,147)	1,652	(23,137)
Net income (loss)	$ 82,243	$ (14,641)	$ (930,149)	$ 114,628	$ (2,937)	$ (914,479)
Cash Flow Data (Unaudited):						
Net cash provided by operating activities	$ 83,910	$ 84,172	$ 181,683	$ 90,118		
Net cash used in investing activities	5,533	230,471	215,139	26,382		
Net cash provided by (used in) financing activities	(38,963)	133,271	(21,388)	(21,378)		
Other Financial Data:						
Adjusted EBITDA (unaudited)	$ 197,903	$ 132,105	$ 247,335	$ 153,679	$ 159,239	$ 258,982
Balance Sheet Data (at period end):						
Working capital (unaudited)	$ 51,214	$ 2,424	$ (17,799)			
Total assets	1,281,134	1,102,406	1,232,146			
Total debt	871,150	309,200	628,000			
Total equity (unaudited)	279,412	682,644	436,231			

Adjusted EBITDA

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 and our predecessor s consolidated and combined financial statements found elsewhere in this prospectus.

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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. The following table provides a reconciliation of our pro forma MRD Segment net income to our pro forma MRD Segment Adjusted EBITDA.

Calculation of Adjusted EBITDA MRD Segment Pro Forma

	Year Ended December 31, 2013	Nine Months Ended September 30, 2014
Net income (loss)	$ (2,937)	$ (914,479)
Interest expense, net	45,972	32,151
Loss on extinguishment of debt		37,248
Income tax expense (benefit)	(1,652)	23,137
Depreciation, depletion and amortization	76,524	106,753
Impairment of proved oil and gas properties	128	
Accretion of AROs	670	495
(Gain) loss on commodity derivative instruments	(3,030)	(17,130)
Cash settlements received (paid) on commodity derivative instruments	12,257	(4,930)
(Gain) loss on sale of properties	6,775	3,167
Acquisition related costs	1,584	1,568
Incentive unit-based compensation expense	22,635	970,877
Exploration costs	1,226	1,213
Non-cash equity (income) loss from MEMP	(1,050)	12,844
Cash distributions from MEMP	137	6,068
Adjusted EBITDA	$ 159,239	$ 258,982

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Summary Reserve, Production and Operating Data for the MRD Segment

The following tables present summary data with respect to the estimated historical net proved oil and natural gas reserves and production and operating data for the MRD Segment as of the dates presented.

The proved reserve estimates presented in the table below were prepared by NSAI, and the probable and possible reserve estimates were prepared by our management and audited by NSAI. Regarding our properties, estimates comprising 100% of the total proved reserves in our reserve report were prepared by NSAI. These reserve estimates were prepared in accordance with current SEC rules regarding oil and natural gas reserve reporting. The following tables also contain certain summary information regarding production and sales of oil and natural gas with respect to such properties.

Please read Business Our Operations as well as Management s Discussion and Analysis of Financial Condition and Results of Operations and the summaries of our reserve report included herein as Appendices B-1 and B-2 in evaluating the material presented below.

Reserve Data

Estimated Proved Reserves		**As of December 31, 2013**
Natural gas (MMcf)		802,254
Oil/Condensate (MBbls)		11,311
NGLs (MBbls)		42,577
Total estimated net proved reserves (MMcfe)		1,125,577
Proved developed producing (MMcfe)		323,351
Proved developed non-producing (MMcfe)		44,290
Proved undeveloped (MMcfe)		757,936
Proved developed reserves as a percentage of total proved reserves		33%
PV-10 of proved reserves (in millions)(1)	$	1,469
Estimated Probable Reserves(2)		
Natural Gas (MMcf)		535,185
Oil/Condensate (MBbls)		10,480
NGLs (MBbls)		33,709
Total estimated net probable reserves (MMcfe)		800,317
PV-10 of probable reserves (in millions)(1)	$	1,052
Estimated Possible Reserves(2)		
Natural Gas (MMcf)		1,080,539
Oil/Condensate (MBbls)		36,376
NGLs (MBbls)		68,686
Total estimated net possible reserves (MMcfe)		1,710,913

PV-10 of possible reserves (in millions)(1)	$	2,386

(1) PV-10 is a non-GAAP financial measure and differs from standardized measure, the most directly comparable GAAP financial measure. Please see Reserves.
(2) Substantially all of our estimated probable and possible reserves are classified as undeveloped.

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Production and Operating Data

	Historical MRD Segment(1)				MRD Segment Pro Forma	
	Year Ended December 31,		Nine Months Ended September 30,		Year Ended December 31,	Nine Months Ended September 30,
	2013	2012	2014	2013	2013	2014
Production and operating data:						
Oil (MBbls)	665	369	689	498	523	677
NGLs (MBbls)	1,457	898	1,612	990	1,454	1,612
Natural gas (MMcf)	34,092	24,130	43,075	25,164	33,205	43,075
Total (MMcfe)	46,819	31,731	56,869	34,075	45,066	56,799
Average net production (MMcfe/d)	128.3	86.7	208.3	124.8	123.5	208.1
Average sales price:						
Oil (per Bbl)	$ 100.76	$ 95.56	$ 96.60	$ 101.77	$ 100.15	$ 96.61
NGLs (per Bbl)	36.99	40.78	41.93	37.69	36.93	41.93
Natural gas (per Mcf)	3.22	2.74	3.87	3.30	3.21	3.87
Average price per Mcfe	$ 4.93	$ 4.35	$ 5.29	$ 5.02	$ 4.73	$ 5.29
Average unit costs per Mcfe:						
Lease operating expenses	$ 0.53	$ 0.77	$ 0.33	$ 0.50	$ 0.52	$ 0.33
Production and ad valorem taxes	$ 0.20	$ 0.24	$ 0.18	$ 0.25	$ 0.19	$ 0.18
General and administrative(2)	$ 1.75	$ 1.21	$ 0.52	$ 0.66	$ 1.27	$ 0.52
Depletion, depreciation and amortization	$ 1.86	$ 1.97	$ 1.89	$ 1.84	$ 1.69	$ 1.88

(1) Includes production and operating data for BlueStone, Golden Energy and Classic Pipeline, which were not contributed to us in connection with our initial public offering. The MRD Segment Pro Forma production and operating data has been adjusted to exclude the production and operating data for BlueStone and Classic Pipeline.

(2) Includes $0.92 and $0.30 per Mcfe of incentive unit compensation expense for the historical MRD Segment for the years ended December 31, 2013 and 2012. The pro forma general and administrative expense for the year ended December 31, 2013 includes $0.50 per Mcfe of incentive unit compensation expense.

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RISK FACTORS

Investing in our common stock involves a high degree of risk. You should carefully consider the risks and uncertainties described below, as well as other information contained in this prospectus, before investing in our common stock. If any of the following risks actually occur, our business, financial condition, operating results or cash flow could be materially and adversely affected.

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 properties 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, 2013, the NYMEX-WTI oil future price ranged from a high of $113.93 per Bbl to a low of $33.98 per Bbl, while the NYMEX-Henry Hub natural gas future price ranged from a high of $7.50 per MMBtu to a low of $1.82 per MMBtu. Any substantial decline in commodity prices will likely have a material adverse effect on our operations and financial condition, as well as on our level of expenditures for the development of our reserves.

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NGLs comprised 23% of our estimated proved reserves at December 31, 2013 and accounted for 17% of our production on a volume equivalent basis for the nine months ended September 30, 2014. Realized NGL prices have decreased recently principally due to significant supply. NGLs are made up of ethane, propane, isobutane, normal butane and natural gasoline, all of which have different uses and different pricing characteristics. A further or extended decline in NGL prices could materially and adversely affect our future business, financial condition and results of operations.

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

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

As a recently formed company, growth in accordance with our business plan, if achieved, could place a significant strain on our financial, technical, operational and management resources. As we expand our activities and increase the number of projects we are evaluating or in which we participate, there will be additional demands on our financial, technical, operational and management resources. Pursuant to a services agreement entered into in connection with our initial public offering, we depend on the services of an entity managed by certain former management members of WildHorse Resources for supervising and managing our drilling operations in the Terryville Complex. See Certain Relationships and Related Party Transactions Services Agreement. Under certain circumstances, this agreement may be terminated by the parties thereto and we may be unable to find replacement services, which could materially and adversely affect our ability to execute our plans for the development of the Terryville Complex. In addition, the failure to continue to upgrade our technical, administrative, operating and financial control systems or the occurrences of unexpected expansion difficulties, including the failure to recruit and retain experienced managers, geologists, engineers and other professionals in the oil and natural gas industry, could have a material adverse effect on our business, financial condition and results of operations and our ability to timely execute our business plan.

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

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

If commodity prices 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.

Significantly lower oil prices, or sustained lower natural gas prices, would 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.

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

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

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

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

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

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.

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;

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- running our casing the entire length of the wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

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

- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

If our drilling results are less than anticipated, the return on our investment for a particular project may not be as attractive as we anticipated and we could incur material write-downs of unevaluated properties and the value of our undeveloped acreage could decline in the future.

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

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

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

Leases on oil and natural gas properties typically have a term of three to five years, after which they expire unless, prior to expiration, production is established within the spacing units covering the undeveloped acres. As of December 31, 2013, we had 10,825 gross (6,985 net) acres scheduled to expire in 2014, 20,078 gross (12,015 net) acres scheduled to expire in 2015, 31,215 gross (20,875 net) acres scheduled to expire in 2016 and 28,228 gross (19,649 net) acres scheduled to expire in 2017. The cost to renew such leases may increase significantly, and we may not be able to renew such leases on commercially reasonable terms or at all. Moreover, many of our leases require lessor consent to pool, which may make it more difficult to hold our leases by production. Any reduction in our current drilling program, either through a reduction in capital expenditures or the unavailability of drilling rigs, could result in the loss of acreage through lease expirations. In addition, in order to hold our current leases scheduled to expire in 2014 and 2015, we will need to operate at least a one-rig program. We cannot assure you that we will have the liquidity to deploy these rigs when needed, or that commodity prices will warrant operating such a drilling program. Any such losses of leases could materially and adversely affect the growth of our asset base, cash flows and results of operations.

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

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

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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, 2013, 10 gross (9.4 net) wells were in various stages of completion. If the wells in the process of being completed do not produce sufficient revenues to return a profit or if we drill dry holes in the future, our business may be materially affected. From January 2011 through December 31, 2013, we have drilled 83 gross (51.9 net) wells and, out of these wells, 3 gross (1.5 net) wells were dry holes.

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

As of December 31, 2013, we had identified 1,582 gross (1,091 net) horizontal drilling locations on our existing acreage. Only 145 of these gross identified drilling locations had proved undeveloped reserves attributed to them in our reserve report. These drilling locations, including those with attributed proved undeveloped reserves, represent a significant part of our growth strategy. Our ability to drill and develop these 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 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.

A majority of our 1,431 gross horizontal drilling locations (as of December 31, 2013) within the Terryville Complex are identified within four distinct zones, with such gross horizontal drilling locations being roughly evenly distributed amongst such four zones. To date, we have drilled 41 horizontal wells within our four primary target zones in the Terryville Complex. Accordingly, we 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. Please see Business Our Operations Drilling Locations for more information on our gross identified drilling locations.

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

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

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

Approximately 67% of our total proved reserves at December 31, 2013 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. Moreover, the development of probable and possible reserves will require additional capital expenditures and such reserves are less certain to be recovered than proved reserves. The reserve data included in our reserve report assumes that substantial capital expenditures are required to develop such undeveloped reserves. We cannot be certain that the estimated costs of the development of these reserves are accurate, that development will occur as scheduled or that the results of such development will be as estimated. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce future net revenues of our estimated proved undeveloped reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved reserves as proved undeveloped reserves.

Our acquisition and development operations require substantial capital expenditures.

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

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

Higher oil and natural gas prices generally increase the demand for rigs, equipment and crews and can lead to shortages of, and increasing costs for, development equipment, 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 thus the results of our operations.

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

We intend to maintain a portfolio of commodity derivative contracts. These commodity derivative contracts include natural gas, oil and NGL financial swaps 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 the derivative contract and, accordingly, prevent us from realizing the benefit of the derivative contract.

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

The process of estimating natural gas and oil reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect our estimated quantities and present value of our reserves.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary.

The process also requires economic assumptions about matters such as natural gas prices, oil prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

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

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

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

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

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

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

The present value of future net cash flows from our proved, probable and possible reserves shown in this prospectus, or PV-10, may not be the current market value of our estimated natural gas and oil reserves. In accordance with rules established by the SEC and the Financial Accounting Standards Board (FASB), we base the

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estimated discounted future net cash flows from our proved reserves on the 12-month average oil and gas index prices, calculated as the unweighted arithmetic average for the first-day-of-the-month price for each month and costs in effect on the date of the estimate, holding the prices and costs constant throughout the life of the properties. Actual future prices and costs may differ materially from those used in the net present value estimate, and future net present value estimates using then current prices and costs may be significantly less than the current estimate. In addition, the 10% discount factor we use when calculating discounted future net cash flows may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the natural gas and oil industry in general.

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

Our producing properties are geographically concentrated in North Louisiana and East Texas. At December 31, 2013, 99% of our total estimated proved reserves and for the nine months ended September 30, 2014, 97% 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.

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. 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.

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.

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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 have established a capital budget for 2014 of approximately $351 million and we intend to rely on cash flow from operating activities 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 decline in commodity prices or a reduction in production levels, however, and we are unable to obtain additional equity or debt financing in the capital markets or access alternative sources of funds, we may be required to reduce the level of our capital expenditures and may lack the capital necessary to replace our reserves or maintain our production levels.

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

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

Our use of 2-D and 3-D seismic data is subject to interpretation and may not accurately identify the presence of oil and natural gas, which could adversely affect the results of our drilling operations.

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

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

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

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

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

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

Recent scientific studies have suggested that emissions of certain gases, commonly referred to as greenhouse gases (GHGs), including carbon dioxide and methane, may be contributing to warming of the earth s atmosphere and other climatic changes. In December 2009, the EPA published its findings that emissions of GHGs present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to the warming of the earth s atmosphere and other climatic changes. Based on these findings, the EPA adopted regulations under existing provisions of the federal Clean Air Act (CAA) that establish Prevention of Significant Deterioration, or PSD, and Title V permit reviews for GHG emissions

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from certain large stationary sources. On June 23, 2014, the Supreme Court held that stationary sources could not become subject to PSD or Title V permitting solely by reason of their GHG emissions. The Court ruled, however, that the EPA may require installation of best available control technology for GHG emissions at sources otherwise subject to the PSD or Title V programs. The EPA has announced that it is currently evaluating the decision and awaiting further action by the courts, and that it will provide relevant guidance on GHG permitting requirements.

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

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

Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations that require reporting of GHGs or otherwise limit emissions of GHGs from our equipment and operations could require us to incur costs to monitor and report on GHG emissions or reduce emissions of GHGs associated with our operations, and such requirements also could adversely affect demand for the oil and natural gas that we produce. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations. Please read 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 Endangered Species Act (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 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

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which such parties agreed to take steps to protect the lesser prairie chicken s habitat and to pay a mitigation fee if its actions harm the lesser prairie chicken s habitat. The threatened species status of the lesser prairie chicken is currently subject to a pending lawsuit by at least three states. The lawsuit challenges FWS recent classification of the lesser prairie chicken. The presence of protected species in areas where we operate could impair our ability to timely complete or carry out those operations, lose leaseholds as we may not be permitted to timely commence drilling operations, cause us to incur increased costs arising from species protection measures, and, consequently, adversely affect our results of operations and financial position.

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

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

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

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

We qualify as a non-financial entity for purposes of the End-User Exception and we utilize such exception so our hedging activity is not subject to mandatory clearing or the margin requirements imposed in connection with mandatory clearing. However, most if not all of our hedge counterparties will be subject to mandatory clearing in connection with their hedging activities with parties who do not qualify for the End-User Exception and, if the Re-Proposed SD/MSP Margin Rule is adopted, will be subject to such rule and required to post margin in accordance with such rule in connection with their swaps with other banks, swap dealers and major swap participants. The Dodd-Frank Act, the rules which have been adopted and not vacated, and, to the extent that the Re-Proposed Position Limit Rule and the Re-Proposed SD/MSP Margin Rule are ultimately effected, such proposed rules could significantly increase the cost of derivative contracts (including through requirements to post collateral), materially alter the terms of derivative contracts, reduce the availability of derivatives to protect

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against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity contracts related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition, and our results of operations.

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

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

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

In August 2012, the EPA adopted rules that subject oil and natural gas production, processing, transmission, and storage operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants programs. The rules include NSPS standards for completions of hydraulically fractured gas wells and establishes specific new requirements for emissions from compressors, controllers, dehydrators, storage vessels, natural gas processing plants and certain other equipment. The final rules seek to achieve a 95% reduction in VOCs emitted by requiring the use of reduced emission completions or green completions on all hydraulically-fractured wells constructed or refractured after January 1, 2015. The rules could require a number of modifications to our operations including the installation of new equipment. The EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. The EPA intends to issue revised rules that are likely to be responsive to some of these requests. On September 23, 2013, the EPA finalized the portion of the rules addressing VOC emissions from storage tanks, including a phase-in period and an alternative emissions limit for older tanks. On July 1, 2014, the EPA announced proposed amendments and clarifications to the NSPS standards. These standards, as well as any future laws and their implementing regulations, may require us to

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obtain pre-approval for the expansion or modification of existing facilities or the construction of new facilities expected to produce air emissions, impose stringent air permit requirements, or utilize specific equipment or technologies to control emissions. Compliance with such rules could result in significant costs, including increased capital expenditures and operating costs, and could adversely impact our business.

In addition, in May 2013, the federal Bureau of Land Management published a supplemental notice of proposed rulemaking governing hydraulic fracturing on federal and Indian lands that replaces a prior draft of proposed rulemaking issued by the agency in May 2012. The revised proposed rule would continue to require public disclosure of chemicals used in hydraulic fracturing on federal and Indian lands, confirmation that wells used in fracturing operations meet appropriate construction standards, and development of appropriate plans for managing flowback water that returns to the surface. The Bureau of Land Management plans to issue a final rule in 2014.

There are also certain governmental reviews either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater. A draft report is expected to be released for public comment and review in late 2014. The EPA s study could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing.

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

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

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

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

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

MEMP is a publicly traded limited partnership. We own MEMP GP, the sole general partner of MEMP, and are entitled to 50% of any cash distributed in respect of MEMP s incentive distribution rights. MRD Holdco owns 5,360,912 subordinated units representing an approximate 6.2% limited partner interest in MEMP. The remainder of the outstanding limited partner interests in MEMP are common units owned by public unitholders. MEMP s partnership agreement requires it to distribute, on a quarterly basis, 100% of its available cash to its partners. We receive only our proportionate share of cash distributions from MEMP based on our partner interests in it. The remainder of the quarterly cash distributions is distributed, pro rata, to the public unitholders (and, in the case of 50% of the incentive distribution rights, to the Funds).

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

- to provide for the proper conduct of partnership business, which could include, but is not limited to, amounts reserved for capital expenditures, working capital and operating expenses;
- to comply with applicable law, any of MEMP s debt instruments or other agreements; and
- to provide funds for distributions to the unitholders and the general partner for any one or more of the next four calendar quarters.

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

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

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

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

Because of these factors, MEMP may not have sufficient available cash each quarter to continue paying distributions at their current level or at all. In addition, our 50% incentive distribution rights are only entitled to distributions from MEMP in any quarter if MEMP has paid at least $0.54625 on each outstanding common unit and subordinated unit for such quarter. If MEMP reduces its per unit distribution below such amounts, we will receive less cash.

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

We own MEMP GP, the sole general partner of MEMP. MEMP is a publicly traded limited partnership. The board of directors of MEMP GP owes specified duties to the MEMP unitholders, and also owes specified duties to us as owner of MEMP GP. As a result of these conflicts, the board of directors of MEMP GP may favor the interests of the MEMP public unitholders over our interests.

Our executive officers have significant equity interests in MEMP. As of September 30, 2014, Mr. Weinzierl, our Chief Executive Officer, owns 485,093 MEMP common units; Mr. Scarff, our President, owns 90,943 MEMP common units; Mr. Cozby, our Senior Vice President and Chief Financial Officer, owns 152,471 MEMP common units; Mr. Forney, our Senior Vice President and Chief Operating Officer, owns 143,081 MEMP common units; Mr. Roane, our Senior Vice President, General Counsel and Corporate Secretary, owns 83,818 MEMP common units; and Mr. Robbins, our Senior Vice President, Corporate Development, owns 89,782 MEMP common units. As a result of our executive officers significant holdings of MEMP common units, our executive officers may favor the interests of MEMP over our interests.

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

We currently manage our investment in MEMP through our ownership interest in MEMP GP. MEMP s partnership agreement, however, gives unitholders of MEMP the right to remove its general partner upon the affirmative vote of holders of 66 2/3% of the MEMP s outstanding units. If MEMP GP were removed as general partner of MEMP, it would receive cash or common units in exchange for its 0.1% general partner interest and incentive distribution rights and would also lose its ability to manage MEMP. While the cash or common units the general partner would receive are intended under the terms of MEMP s partnership agreement to fully compensate MEMP GP in the event such an exchange is required, the value of the investments we make with the

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cash or the common units may not over time be equivalent to the value of the general partner interest and the incentive distribution rights had MEMP GP retained them.

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

We have a substantial amount of indebtedness. As of September 30, 2014, we had aggregate indebtedness of approximately $628 million at the MRD Segment. The terms and conditions governing our indebtedness:

- require us to dedicate a substantial portion of our cash flow from operations to service our existing debt, thereby reducing the cash available to finance our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate;
- increase our vulnerability to economic downturns and adverse developments in our business;
- limit our ability to access the capital markets to raise capital on favorable terms or to obtain additional financing for working capital, capital expenditures or acquisitions or to refinance existing indebtedness;
- place restrictions on our ability to obtain additional financing, make investments, lease equipment, sell assets and engage in business combinations;
- place us at a competitive disadvantage relative to competitors with lower levels of indebtedness in relation to their overall size or less restrictive terms governing their indebtedness; and
- limit management s discretion in operating our business.

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

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

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

- refinancing or restructuring our debt;
- selling assets;
- reducing or delaying capital investments; or
- seeking to raise additional capital.

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

Furthermore, our ability to restructure or refinance our indebtedness will depend on the condition of the capital markets and our financial condition at such time. Any refinancing of our indebtedness could be at higher interest rates and may require us to comply with more onerous covenants, which could further restrict our business operations. The terms of existing or future debt instruments, including our revolving credit facility, may restrict us from adopting some of these alternatives. In addition, any failure to make payments of interest and principal on our outstanding indebtedness on a timely basis would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness. In the absence of sufficient cash flows and capital resources, we could face substantial liquidity problems and might be required to dispose of material assets or operations to meet our debt service and other obligations. Our existing debt instruments currently restrict, and we expect our revolving credit facility will restrict, our ability to dispose of assets and our use of the proceeds from such disposition. We may not be able to consummate those dispositions, and the proceeds of any such disposition may not be adequate to meet any debt service obligations then due. These alternative measures may not be successful and may not permit us to meet our scheduled debt service obligations.

Risks Relating to this Offering and Our Common Stock

The underwriters of this offering may waive or release parties to the lock-up agreements entered into in connection with this offering, which could adversely affect the price of our common stock.

The Company, the selling stockholders, our directors and officers and WHR Incentive LLC, a limited liability company beneficially owned by Messrs. Anthony Bahr and Jay Graham, have entered into lock-up agreements with respect to their common stock, pursuant to which they are subject to certain resale restrictions for a period of 60 days following the date of this prospectus. Citigroup Global Markets Inc., at any time, may release all or any portion of the common stock subject to the foregoing lock-up agreements. If the restrictions under the lock-up agreements are waived, then common stock will be available for sale into the public markets, which could cause the market price of our common stock to decline and impair our ability to raise capital.

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.

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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. Upon completion of this offering, MRD Holdco will own in the aggregate approximately 40% of the combined voting power of our common stock (or approximately 38% if the underwriters option to purchase additional shares of common stock from the selling stockholders is exercised in full). MRD Holdco and certain former management members of WildHorse Resources (which former management members, upon completion of this offering, will own in the aggregate approximately 18% of the combined voting power of our common stock (or approximately 18% if the underwriters option to purchase additional shares of common stock from the selling stockholders is exercised in full)) are party to a voting agreement, pursuant to which the former management members of WildHorse Resources agree, among other things, to vote all of their shares as directed by MRD Holdco. As a result, MRD Holdco and, thus, NGP are able to control matters requiring stockholder approval, including the election of directors, changes to our organizational documents and significant corporate transactions. This concentration of ownership makes it unlikely that any other holder or group of holders of our common stock will be able to affect the way we are managed or the direction of our business. The interests of NGP with respect to matters potentially or actually involving or affecting us, such as future acquisitions, financings and other corporate opportunities and attempts to acquire us, may conflict with the interests of our other stockholders. Given this concentrated ownership, NGP would have to approve any potential acquisition of us. In addition, certain of our directors are currently employees of NGP. These directors duties as employees of NGP may conflict with their duties as our directors, and the resolution of these conflicts may not always be in our or your best interest.

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

Most of our officers hold similar positions with MRD Holdco and MEMP GP, and many of our directors, who are responsible for managing the direction of our operations and acquisition activities, hold positions of responsibility with other entities (including NGP-affiliated entities) that are in the business of identifying and acquiring oil and natural gas properties. For example, the Funds and their affiliates (including NGP) are in the business of investing in oil and natural gas companies with independent management teams that also seek to acquire oil and natural gas properties, and MRD Holdco and MEMP are both in the business of acquiring and developing oil and natural gas properties. Mr. Hersh, one of our directors, is a managing partner of NGP; Mr. Gieselman, one of our directors, is a managing director of NGP; Mr. Weber, one of our directors, is a managing partner of NGP and serves as Chief Operating Officer for NGP; Mr. Innamorati, one of our directors, is a director of MEMP GP, and Mr. Weinzierl, our Chief Executive Officer and one of our directors, is the Chief Executive Officer and Chairman of MEMP GP, and was a managing director and operating partner of NGP and continues to hold ownership interests in the Funds and certain of their affiliates. Our officers 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. For additional discussion of our management s business affiliations and the potential conflicts of interest of which our stockholders should be aware, see Certain Relationships and Related Party Transactions.

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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. Please read Description of Capital Stock.

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

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

- the requirement that we have a majority of independent directors on our Board;

- the requirement that we have a nominating committee that is composed entirely of independent directors with a written charter addressing the committee s purpose and responsibilities;

- the requirement that we have a compensation committee that is composed entirely of independent directors; and

- the requirement for an annual performance evaluation of the nominating and compensation committees.

We utilize the foregoing exemptions from the applicable corporate governance requirements. As a result, we do not have a majority of independent directors and do not have a compensation committee. See Management. 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.

We may sell additional shares of common stock in subsequent public offerings or otherwise, including to finance acquisitions. Our amended and restated certificate of incorporation authorizes us to issue 600,000,000 shares of common stock, of which 193,559,211 shares are outstanding. The outstanding share number includes 49,220,000 shares registered and sold in our initial public offering and up to 34,500,000 shares that the selling stockholders are selling in this offering (assuming the underwriters exercise their option to acquire additional shares in full), all of which may be resold immediately in the public market. Following the expiration of the applicable lock-up period, which is 60 days after the date of this prospectus, 111,928,871 shares of our common stock may be sold into the public market (assuming the underwriters do not exercise their option to acquire additional shares), subject to compliance with the Securities Act or exemptions therefrom. See Shares Eligible for Future Sale for a discussion of the shares of our common stock that may be sold into the public market in the future.

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

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.

We cannot predict the size of future issuances of our 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.

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. See Description of Capital Stock Anti-Takeover Effects of Provisions of Our Amended and Restated Certificate of Incorporation, our Amended and Restated Bylaws and Delaware Law.

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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, as described under the caption Certain Relationships and Related Party Transactions. 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. See Description of Capital Stock Limitation of Liability and Indemnification Matters.

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 Securities and Exchange Act of 1934 (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. We also expect that being a company with publicly traded common stock and these new rules and regulations will 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

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Section 404 of the Sarbanes-Oxley Act, we will be required to include a report of management on our internal control over financial reporting in our Annual Reports on Form 10-K beginning with the Form 10-K for the year ending December 31, 2014. In order to maintain and improve the effectiveness of our disclosure controls and procedures and internal control over financial reporting, significant resources and management oversight are required. This may divert management s attention from other business concerns, which could have a material adverse effect on our business, financial condition, results of operations and cash flows. If we are unable to conclude that our disclosure controls and procedures and internal control over financial reporting are effective, or if we are no longer an emerging growth company and our independent public accounting firm is unable to provide us with an unqualified report on our internal control over financial reporting in future years, investors may lose confidence in our financial reports and our stock price may decline.

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

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

We are an emerging growth company, as defined in the JOBS Act, and we currently take advantage of certain exemptions from various reporting requirements that are applicable to other public companies, including, but not limited to, not being required to comply with the auditor attestation requirements of Section 404 of the Sarbanes-Oxley Act, reduced disclosure obligations regarding executive compensation in our periodic reports and proxy statements, and exemptions from the requirements of holding a nonbinding advisory vote on executive compensation and stockholder approval of any golden parachute payments not previously approved. We intend to take advantage of these reporting exemptions until we are no longer an emerging growth company. We cannot predict if investors will find our common stock less attractive because we rely and will continue to rely on these exemptions. If some investors find our common stock less attractive as a result, there may be a less active trading market for our common stock and our stock price may be more volatile.

We will cease to be an emerging growth company upon the earliest of (i) the last day of the fiscal year in which we have $1.0 billion or more in annual revenues, (ii) the date on which we become a large accelerated filer (the fiscal year-end on which the total market value of our common equity securities held by non-affiliates is $700 million or more as of June 30), (iii) the date on which we issue more than $1.0 billion of non-convertible debt over a three-year period, or (iv) the last day of the fiscal year following the fifth anniversary of our initial public offering.

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

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

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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 shareholders 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.

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This prospectus contains forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Securities Exchange Act of 1934, as amended (the Exchange Act). Forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements, other than statements of historical fact included in this prospectus, are forward-looking statements. When used in this prospectus, the words could, should, will, believe, anticipate, intend, estimate, expect, may, continue, pre pursue, target, project, forecast, the negative of such terms, or other similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words.

Forward-looking statements may include statements about:

- our business strategy;
- our estimated reserves and the present value thereof;
- our technology;
- our cash flows and liquidity;
- our financial strategy, budget, projections and future operating results;
- realized commodity prices;
- timing and amount of future production of reserves;
- availability of drilling and production equipment;
- availability of pipeline capacity;
- availability of oilfield labor;
- the amount, nature and timing of capital expenditures, including future development costs;
- availability and terms of capital;

drilling of wells, including statements made about future horizontal drilling activities;

competition;

government regulations;

marketing of production;

exploitation or property acquisitions;

costs of exploiting and developing our properties and conducting other operations;

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;

taxation of the oil and natural gas industry;

developments in other countries that produce oil and natural gas;

uncertainty regarding future operating results;

plans and objectives of management; and

plans, objectives, expectations and intentions contained in this prospectus that are not historical.

These types of statements, other than statements of historical fact included in this prospectus, are forward-looking statements. These forward-looking statements may be found in Summary, Risk Factors, Management s Discussion and Analysis of Financial Condition and Results of Operations and other sections of this prospectus. 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 prospectus 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 prospectus 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 the Risk Factors section of this prospectus and elsewhere in this prospectus. 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.

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USE OF PROCEEDS

We will not receive any proceeds from the sale of shares of our common stock by the selling stockholders, including pursuant to any exercise by the underwriters of their option to purchase additional shares of our common stock. The selling stockholders may be deemed under federal securities laws to be underwriters with respect to the common stock they may sell in connection with this offering.

DIVIDEND POLICY

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

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MARKET PRICE OF OUR COMMON STOCK

Our common stock began trading on the NASDAQ under the symbol MRD on June 13, 2014. Prior to that, there was no public market for our common stock. On November 12, 2014, the last reported sale price for our common stock on the NASDAQ was $23.53 per share. As of November 12, 2014, we had approximately 193,559,211 shares of common stock issued and outstanding and 64 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.

	High	Low
Fourth Quarter 2014 (through November 12, 2014)	$ 28.44	$ 19.86
Third Quarter 2014	$ 30.32	$ 22.50
Second Quarter 2014 (beginning June 13, 2014)	$ 25.90	$ 21.07

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SELECTED HISTORICAL FINANCIAL DATA

Prior to the closing of our initial public offering, MRD LLC and its consolidated subsidiaries, our accounting predecessor, controlled MEMP through its ownership of MEMP GP, the general partner of MEMP. Because MRD LLC controlled MEMP through its ownership of the general partner, MRD LLC was required to consolidate MEMP for accounting and financial reporting purposes even though MRD LLC owned a minority of its partner interests and MRD LLC and MEMP had independent capital structures. MRD LLC received cash distributions from MEMP as a result of its partner interests and incentive distribution rights in MEMP, when declared and paid by MEMP. In connection with the closing of our initial public offering, MRD LLC contributed substantially all of its existing assets to us in exchange for shares of our common stock. Through our ownership of MEMP GP, we continue to control MEMP and therefore continue to consolidate the results of MEMP into our consolidated financial statements in current and future periods.

Our predecessor had two reportable business segments, both of which were engaged in the acquisition, exploitation, development and production of oil and natural gas properties:

- MRD reflected all of MRD LLC s consolidating subsidiaries except for MEMP and its subsidiaries.

- MEMP reflected the consolidated and combined operations of MEMP and its subsidiaries.

We continue to have two reportable segments. For more information regarding reportable business segments, please see the predecessor s audited historical financial statements and related notes and our unaudited historical interim financial statements included elsewhere in this prospectus.

The following tables include selected historical financial data for us and our predecessor, as well as the MRD Segment as of and for the periods indicated. The selected historical financial data of our predecessor as of and for the years ended December 31, 2013 and 2012 were derived from the audited historical financial statements of our predecessor included elsewhere in this prospectus. The selected historical financial data as of September 30, 2014 and for the nine months ended September 30, 2014 and 2013 were derived from our unaudited interim financial statements included elsewhere in this prospectus. The selected historical financial data of the MRD Segment as of and for the years ended December 31, 2013 and 2012 were derived from certain financial information used in the preparation of our predecessor s audited financial statements. The selected historical financial data for the MRD Segment as of September 30, 2014 and for the nine months ended September 30, 2014 and 2013 were derived from certain financial information used in the preparation of our unaudited interim financial statements.

The selected unaudited pro forma data for the nine months ended September 30, 2014 and for the year ended December 31, 2013 has been prepared to give pro forma effect to: (i) the exclusion of both BlueStone and Classic Pipeline as well as the MEMP subordinated units, none of which were conveyed to us in connection with our initial public offering; (ii) certain restructuring transactions that took place in connection with our initial public offering; (iii) the MEMP Wyoming Acquisition and the MEMP Offerings; (iv) our private placement on July 10, 2014 of $600.0 million aggregate principal amount of 5.875% senior unsecured notes at par as well as MEMP s private placement on July 17, 2014 of $500.0 million aggregate principal amount of 6.875% senior unsecured notes at 98.485% of par (collectively referred to as the Debt Offerings); and (v) incremental federal income tax expense.

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We derived the data in the following tables from, and the following tables should be read together with and is qualified in its entirety by reference to, our historical financial statements (including those of our predecessor) and our pro forma financial statements and the accompanying notes included elsewhere in this prospectus. You should also read Management s Discussion and Analysis of Financial Condition and Results of Operations and our pro forma and historical consolidated financial statements, all included elsewhere in this prospectus. Among other things, those historical consolidated and combined financial statements and pro forma financial statements include more detailed information regarding the basis of presentation for the following data.

	Year Ended December 31, 2013	Year Ended December 31, 2012 (Predecessor)	Nine Months Ended September 30, 2014 (unaudited)	Nine Months Ended September 30, 2013 (Predecessor) (unaudited)	Memorial Resource Development Corp. Pro Forma Year Ended December 31, 2013	Memorial Resource Development Corp. Pro Forma Nine Months Ended September 30, 2014 (unaudited)
	(in thousands)					
Statement of Operations Data:						
Revenues:						
Oil and natural gas sales	$ 571,948	$ 393,631	$ 669,301	$ 420,857	$ 740,221	$ 758,811
Other revenues	3,075	3,237	3,584	1,884	2,268	3,034
Total revenues	575,023	396,868	672,885	422,741	742,489	761,845
Costs and expenses:						
Lease operating	113,640	103,754	111,887	81,746	165,092	136,561
Pipeline operating	1,835	2,114	1,596	1,343	1,835	1,596
Exploration	2,356	9,800	1,465	2,265	2,356	1,465
Production and ad valorem taxes	27,146	23,624	33,623	23,478	53,079	45,515
Depreciation, depletion and amortization	184,717	138,672	215,906	132,328	233,244	244,357
Impairment of proved oil and gas properties	6,600	28,871	67,181	21	4,201	67,181
Incentive unit compensation expense			969,390	19,069		968,367
General and administrative	125,358	69,187	61,061	55,982	101,098	61,045
Accretion of asset retirement obligations	5,581	5,009	4,601	4,016	5,803	4,741
(Gain) loss on commodity derivatives	(29,294)	(34,905)	11,580	(29,556)	(29,311)	11,580
(Gain) loss on sale of property	(85,621)	(9,761)	3,057	(86,218)	3,927	3,167
Other, net	649	502	(12)	622	649	(12)
Total costs and expenses	352,967	336,867	1,481,335	205,096	541,973	1,545,563
Operating income (loss)	222,056	60,001	(808,450)	217,645	200,516	(783,718)
Other income (expense)						
Interest expense, net	(69,250)	(33,238)	(104,928)	(41,994)	(117,843)	(108,998)
Loss on extinguishment of debt			(37,248)			(37,248)
Amortization of investment premium		(194)				
Other, net	145	535	102	81	143	102
Total other income (expense)	(69,105)	(32,897)	(142,074)	(41,913)	(117,700)	(146,144)
Income tax benefit (expense)	(1,619)	(107)	(14,398)	(1,432)	(29,814)	(21,836)
Net income (loss)	$ 151,332	$ 26,997	$ (964,922)	$ 174,300	$ 53,002	$ (951,698)
Cash Flow Data:						
Net cash provided by operating activities	$ 277,823	$ 240,404	$ 365,460	$ 237,176		
Net cash used in investing activities	367,443	606,738	1,496,677	235,883		
Net cash provided by financing activities	117,950	361,761	1,063,812	32,261		

Balance Sheet Data (at period end):			
Working capital (deficit)	$ 48,256	$ 63,054	$ (71,531)
Total assets	2,829,161	2,459,304	4,021,667
Total debt	1,663,217	939,382	2,111,800
Total equity (including noncontrolling interests)	858,132	1,276,709	1,458,999

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	MRD Segment				MRD Segment Pro Forma	
	Year Ended December 31,		Nine Months Ended September 30,		Year Ended December 31,	Nine Months Ended September 30,
	2013	2012	2014	2013	2013	2014
			(unaudited)		(unaudited)	
			(in thousands)			
Statement of Operations Data:						
Revenues:						
Oil and natural gas sales	$ 230,751	$ 138,032	$ 300,931	$ 171,013	$ 212,603	$ 299,242
Other revenues	807	782	561	348		11
Total revenues	231,558	138,814	301,492	171,361	212,603	299,253
Costs and expenses:						
Lease operating	25,006	24,438	18,657	17,065	23,354	18,723
Exploration	1,226	7,337	1,213	1,137	1,226	1,213
Production and ad valorem taxes	9,362	7,576	10,494	8,563	8,485	10,443
Depreciation, depletion and amortization	87,043	62,636	107,496	62,605	76,524	106,753
Impairment of proved oil and gas properties	2,527	18,339			128	
Incentive unit compensation expense			969,390	19,069		968,367
General and administrative	81,758	38,414	29,301	22,466	57,498	29,285
Accretion of asset retirement obligations	728	632	495	547	670	495
(Gain) loss on commodity derivatives	(3,013)	(13,488)	(17,130)	(8,361)	(3,030)	(17,130)
(Gain) loss on sale of property	(82,773)	(2)	3,057	(83,370)	6,775	3,167
Other, net	2	364		(25)	2	
Total costs and expenses	121,866	146,246	1,122,973	39,696	171,632	1,121,316
Operating income (loss)	109,692	(7,432)	(821,481)	131,665	40,971	(822,063)
Other income (expense)						
Interest expense, net	(27,349)	(12,802)	(44,355)	(15,947)	(45,972)	(32,151)
Loss on extinguishment of debt			(37,248)			(37,248)
Earnings from equity investments	1,066	4,880	(12,844)	(24)	269	18
Other, net	145	535	102	81	143	102
Total other income (expense)	(26,138)	(7,387)	(94,345)	(15,890)	(45,560)	(69,279)
Income tax (expense) benefit	(1,311)	178	(14,323)	(1,147)	1,652	(23,137)
Net income (loss)	$ 82,243	$ (14,641)	$ (930,149)	$ 114,628	$ (2,937)	$ (914,479)
Cash Flow Data (Unaudited):						
Net cash provided by operating activities	$ 83,910	$ 84,172	$ 181,683	$ 90,118		
Net cash used in investing activities	5,533	230,471	215,139	26,382		
Net cash provided by (used in) financing activities	(38,963)	133,271	(21,388)	(21,378)		
Other Financial Data:						
Adjusted EBITDA (unaudited)	$ 197,903	$ 132,105	$ 247,335	$ 153,679	$ 159,239	$ 258,982
Balance Sheet Data (at period end):						
Working capital (unaudited)	$ 51,214	$ 2,424	$ (17,799)			
Total assets	1,281,134	1,102,406	1,232,146			
Total debt	871,150	309,200	628,000			
Total equity (unaudited)	279,412	682,644	436,231			

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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 included elsewhere in this prospectus. 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 described under the heading Risk Factors included elsewhere in this prospectus. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. Also see Cautionary Note Regarding Forward-Looking Statements included elsewhere in this prospectus.

Overview

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

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

Following the completion of our initial public offering, MRD LLC distributed to MRD Holdco (i) its interests in BlueStone Natural Resources Holdings, LLC (BlueStone), MRD Royalty LLC (MRD Royalty), MRD Midstream LLC (MRD Midstream), Golden Energy Partners LLC (Golden Energy) and Classic Pipeline & Gathering, LLC (Classic Pipeline), (ii) the MEMP subordinated units; (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.

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.

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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. MRD LLC previously received cash distributions from MEMP as a result of its partner interests and incentive distribution rights in MEMP, when declared and paid by MEMP. We will continue to receive cash distributions from MEMP as a result of our 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. For additional information regarding this financial measure, see Summary Historical Consolidated and Combined Pro Forma Financial Data Adjusted EBITDA.

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

MRD reflects the combined operations of the Company, MRD LLC, WildHorse Resources and its previous owners, Classic and Classic GP, Black Diamond, BlueStone, Beta Operating and MEMP GP.

MEMP reflects the combined operations of MEMP, its previous owners, and historical dropdown transactions that occurred between MEMP and other MRD LLC consolidating subsidiaries.

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

acquisition by MEMP of all the outstanding membership interests in Tanos Energy, LLC (Tanos) for a purchase price of approximately $77.4 million on October 1, 2013;

acquisition by MEMP of all the outstanding membership interests in Prospect Energy, LLC (Prospect Energy) from Black Diamond for a purchase price of approximately $16.3 million on October 1, 2013;

acquisition by MEMP of certain of the oil and natural gas properties in Jackson County, Texas from MRD LLC for a purchase price of approximately $2.6 million on October 1, 2013; 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 on March 28, 2013.

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

The MEMP Segment is engaged in the acquisition, exploitation, development and production of oil and natural gas properties, with assets consisting primarily of producing oil and natural gas properties that are principally located in East Texas/North Louisiana, the Rockies, South Texas, the Permian 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.

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Recent Developments

MRD Segment

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. We received net proceeds of approximately $380.2 million, after deducting underwriting discounts and commissions and fees and expenses associated with the offering and the restructuring transactions entered into in connection with the offering. We used approximately $360.0 million of our initial public offering proceeds to redeem the PIK notes on June 27, 2014. In addition, MRD Holdco sold 27,720,000 shares of our common stock in our initial public offering as a selling stockholder. We did not receive any proceeds from the sale of shares by MRD Holdco.

On July 10, 2014, we completed a private placement of $600.0 million aggregate principal amount of 5.875% senior unsecured notes (the MRD Senior Notes) at par. The MRD Senior Notes will mature on July 1, 2022. Interest on the MRD Senior Notes will accrue from July 10, 2014 and will be payable semiannually on January 1 and July 1 of each year, commencing on January 1, 2015. The net proceeds of approximately $586.0 million, after deducting the initial purchasers discounts and commissions and estimated offering expenses, were used to repay a portion of the borrowings outstanding under our revolving credit facility. The amounts repaid under our revolving credit facility were incurred to repay the amounts outstanding under WildHorse Resources credit facilities in connection with the closing of our initial public offering. In conjunction with the closing of the offer and sale of the MRD Senior Notes, the borrowing base under MRD s revolving credit facility was automatically decreased by $56.5 million.

MEMP Segment

On July 1, 2014, MEMP acquired certain oil and natural gas liquids properties in Wyoming (the MEMP Wyoming Acquisition) from Merit Energy Company, LLC and certain of its affiliates (Merit) for an aggregate adjusted purchase price of approximately $911.7 million, including estimated customary post-closing adjustments. The MEMP Wyoming Acquisition had an effective date of April 1, 2014. In conjunction with the closing of the MEMP Wyoming Acquisition, the borrowing base under MEMP s revolving credit facility was increased from $870 million to $1.44 billion. The MEMP Wyoming Acquisition was funded with borrowings under MEMP s revolving credit facility.

On July 15, 2014, MEMP issued 9,890,000 common units representing limited partner interests in MEMP (including 1,290,000 common units purchased pursuant to the full exercise of the underwriters option to purchase additional common units) to the underwriters at a negotiated price of $22.25 per unit generating total net proceeds of approximately $220.0 million after offering expenses. The net proceeds from this equity offering were used to repay a portion of the outstanding borrowings under MEMP s revolving credit facility.

On July 17, 2014, MEMP and its wholly-owned subsidiary Memorial Production Finance Corporation (Finance Corp. and, together with MEMP, the MEMP Issuers) completed a private placement of $500.0 million aggregate principal amount of 6.875% senior unsecured notes due 2022 (the 2022 Senior Notes). The 2022 Senior Notes were issued at 98.485% of par and are fully and unconditionally guaranteed (subject to customary release provisions) on a joint and several basis by all of the 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, commencing on February 1, 2015. The net proceeds of approximately $484.9 million, after deducting the initial purchasers discounts and commissions but before estimated offering expenses, were used to repay a portion of the borrowings outstanding under MEMP s revolving credit facility and for general partnership purposes. In conjunction with the closing of the offer and sale of the 2022 Senior Notes, the borrowing base under MEMP s revolving credit facility was automatically decreased from $1.440 billion to $1.315 billion.

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On September 9, 2014, MEMP issued 14,950,000 common units representing limited partner interests in MEMP (including 1,950,000 common units purchased pursuant to the full exercise of the underwriters option to purchase additional common units) to the public at an offering price of $22.29 per unit generating total net proceeds of approximately $321.6 million after underwriting discounts and commissions and offering expenses. The net proceeds from this equity offering were used to repay a portion of the outstanding borrowings under MEMP s revolving credit facility

Sources of Revenues

Both the MRD Segment s and the MEMP Segment 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 segments intend to periodically enter into derivative contracts with respect to a significant portion of their estimated natural gas and oil production through various transactions that fix the future prices received. These transactions may include price swaps whereby the applicable segment will receive a fixed price for production and pay a variable market price to the contract counterparty. Additionally, either segment may enter into costless collars, whereby the applicable segment receives the excess, if any, of the fixed floor over the floating rate or pay the excess, if any, of the floating rate over the fixed ceiling price. At the end of each period the fair value of these commodity derivative instruments are estimated and, because hedge accounting is not elected, the changes in the fair value of unsettled commodity derivative instruments are recognized in earnings at the end of each accounting period.

Principal Components of Cost Structure

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

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

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

Impairment of unproved and proved properties. For unproved properties, these primarily include costs associated with lease expirations. 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, NGLs and oil. 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 Unaudited Condensed Consolidated and Combined Financial Statements.

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

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

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

Results of Operations

Consolidated

Selected consolidated and combined results of operations for the years ended December 31, 2013 and 2012 and the nine months ended September 30, 2014 and 2013 are presented below and have been derived from our predecessor s and our consolidated and combined financial statements included elsewhere in this prospectus. Also see our predecessor s consolidated and combined financial statements and related notes included elsewhere in this prospectus for a description of our predecessor s previous owners.

	For Year Ended December 31,		For Nine Months Ended September 30,	
	2013	2012	2014	2013
			(unaudited)	
Oil and natural gas sales	$ 571,948	$ 393,631	$ 669,301	$ 420,857
Lease operating	113,640	103,754	111,887	81,746
Exploration	2,356	9,800	1,465	2,265
Production and ad valorem taxes	27,146	23,624	33,623	23,478
Depreciation, depletion and amortization	184,717	138,672	215,906	132,328
Incentive unit compensation expense			67,181	21
Impairment of proved oil and gas properties	6,600	28,871	969,390	19,069
General and administrative	125,358	69,187	61,061	55,982
(Gain) loss on commodity derivative instruments	(29,294)	(34,905)	11,580	(29,556)
(Gain) loss on sale of properties	(85,621)	(9,761)	3,057	(86,218)
Interest expense, net	69,250	33,238	(104,928)	(41,994)
Loss on extinguishment of debt			(37,248)	
Net income (loss)	151,332	26,997	(964,922)	174,300

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

Our predecessor recorded net income of $151.3 million in 2013 compared to net income of $27.0 million in 2012. The increase in net income was primarily due to increases in revenues and gains on the sale of properties, partially offset by increases in DD&A, general and administrative expenses and interest expense.

Oil and natural gas revenues were $571.9 million, an increase of $178.3 million from 2012. Production increased 28,062 MMcfe (approximately 37%) while the average realized sales price increased $0.31 per Mcfe. Production increases were primarily due to acquisitions and drilling activities in North Louisiana and East Texas. The favorable volume variance contributed to a $147.2 million increase in revenues and the favorable pricing variance contributed to a $31.1 million increase in revenues.

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The $46.0 million increase in DD&A expense was primarily due to increased production volumes related to acquisitions and drilling activities in North Louisiana and East Texas. Increased production volumes increased DD&A expense by $51.8 million, while a 3% decrease in the DD&A rate between periods decreased DD&A expense by $5.8 million.

During 2013, BlueStone sold its remaining interests in certain properties in East Texas to a third party and recognized a gain of $89.5 million. This gain was partially offset by a loss of $6.8 million recorded by Black Diamond on the sale of certain of its Wyoming properties. During 2012, the previous owners of oil and gas properties acquired by MEMP recognized a gain of approximately $9.8 million related to the sale of properties in West Texas.

Interest expense was $69.3 million in 2013, an increase of $36.0 million from 2012. The increase in interest expense was primarily due to higher levels of indebtedness as debt outstanding was $939.4 million at December 31, 2012 compared to $1,663.2 million at December 31, 2013.

Please see segment discussion below for further information regarding changes in other line items on a segment basis.

Nine Months Ended September 30, 2014 Compared to the Nine Months Ended September 30, 2013

A net loss of $964.9 million was generated for the nine months ended September 30, 2014 compared to net income of $174.3 million for nine months ended September 30, 2013. The net loss recorded during 2014 was primarily due to compensation expense recognized associated with incentive units as discussed below.

Oil, natural gas and NGL revenues for 2014 totaled $669.3 million, an increase of $248.4 million compared with 2013. Production increased 33.9 Bcfe (approximately 45%) primarily due to acquisitions and drilling activities in North Louisiana and East Texas. The average realized sales price increased $0.53 per Mcfe primarily due to higher natural gas prices. The favorable volume and pricing variance contributed to an approximate $190.3 million and $58.2 million increase in revenues, respectively.

Lease operating expenses were $111.9 million and $81.7 million for 2014 and 2013, respectively, an increase of $30.2 million primarily due to increased production volumes. On a per Mcfe basis, lease operating expenses decreased to $1.03 for 2014 from $1.09 for 2013. During 2014, MEMP recorded $2.9 million of estimated environmental remediation expenses associated with its Permian and Wyoming oil and gas properties.

DD&A expense for 2014 was $215.9 million compared to $132.3 million for 2013, a $83.6 million increase primarily due to both an increase in the depletable cost base and increased production volumes related to acquisitions and drilling activities in North Louisiana and East Texas. Increased production volumes caused DD&A expense to increase by an approximate $59.8 million and the change in the DD&A rate between periods caused DD&A expense to increase by an approximate $23.8 million.

Impairments for 2014 totaled $67.2 million primarily related to certain MEMP properties located in South Texas. The estimated future cash flows expected for these properties were compared to their carrying values and determined to be unrecoverable in part due to a downward revision of estimated proved reserves based on declining commodity prices and increased operating costs. We recognized impairment charges of less than $0.1 million on a consolidated basis for 2013.

Incentive unit compensation expense for 2014 was $969.4 million, of which $831.1 million related to WildHorse Resources incentive units, $137.3 million related to MRD Holdco incentive units, and $1.0 million related to BlueStone incentive units. Incentive unit compensation expense of approximately $19.1 million was recorded by BlueStone in 2013. Net proceeds generated from the sale of oil and gas properties were used to pay a distribution to BlueStone incentive unit holders. For more information regarding the recognition of compensation expense associated with incentive units during 2014, see Note 12 of the Notes to Unaudited Condensed Consolidated and Combined Financial Statements included elsewhere in this prospectus.

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General and administrative expenses for 2014 were $61.1 million compared to $56.0 million for 2013. General and administrative expenses for 2014 included $6.9 million of compensation expense associated with long-term incentive plans and $5.5 million of acquisition-related costs. General and administrative expenses for 2013 included $5.8 million recorded by Tanos associated with incentive units forfeited, $2.3 million of compensation expense associated with long-term incentive plans and $5.1 million of acquisition-related costs. Increased salaries and employee headcount also contributed to increased general and administrative expenses between periods. For more information regarding the recognition of compensation expense associated with long-term incentive plans and incentive units, see Notes 11 and 12 of the Notes to Unaudited Condensed Consolidated and Combined Financial Statements included elsewhere in this prospectus.

Net losses on commodity derivative instruments of $11.6 million were recognized during 2014, consisting of $19.9 million of cash settlement payouts, offset by a $8.3 million increase in the fair value of open hedge positions. Net gain on commodity derivative instruments of $29.6 million were recognized during 2013, consisting of $23.2 million of cash settlement receipts in addition to a $6.4 million increase in the fair value of open hedge positions.

Interest expense was $104.9 million during 2014, an increase of $62.9 million from 2013. The increase in interest expense was primarily due to higher levels of indebtedness. The mix of debt was also a contributing factor. The MRD Senior Notes, MEMP s 2022 Senior Notes and MEMP s 2021 Senior Notes carry a higher interest rate compared to debt under revolving credit facilities.

We irrevocably deposited with the PIK notes trustee approximately $360.0 million on June 27, 2014, which was an amount sufficient to fund the redemption of the PIK notes on the redemption date and to satisfy and discharge our obligations under the PIK notes and the related indenture. The discharge became effective upon the irrevocable deposit of the funds with the PIK notes trustee. An extinguishment loss of $23.6 million was recognized related to the redemption of the PIK notes.

In connection with the closing of our initial public offering, the 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.

During 2013, BlueStone entered into an agreement with a third party to sell its remaining interest in certain properties and recognized a gain of $90.1 million. This gain was partially offset by a loss of $6.8 million recorded by Black Diamond on the sale of certain oil and gas properties.

Please see segment discussion below for further information regarding changes in other line items on a segment basis.

MRD Segment

The MRD Segment s consolidated and combined results of operations for the years ended December 31, 2013 and 2012 and the nine months ended September 30, 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 sale of assets by BlueStone in East Texas in July 2013 for approximately $117.9 million;
- the acquisition by WildHorse Resources of assets in Louisiana in March 2013 for approximately $67.1 million; and

the distribution by MRD LLC of the following to MRD Holdco: (i) BlueStone, which sold substantially all of its assets in July 2013 for $117.9 million, MRD Royalty LLC, which owns certain immaterial leasehold interests and overriding royalty interests in Texas and Montana, MRD Midstream LLC, which owns an indirect interest in certain midstream assets in North Louisiana, Golden Energy and Classic Pipeline and (ii) 5,360,912 subordinated units of MEMP.

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

acquisition by MEMP of all the outstanding membership interests in Tanos for a purchase price of approximately $77.4 million on October 1, 2013;

acquisition by MEMP of all the outstanding membership interests in Prospect from Black Diamond for a purchase price of approximately $16.3 million on October 1, 2013;

acquisition by MEMP of certain of the oil and natural gas properties in Jackson County, Texas from MRD LLC for a purchase price of approximately $2.6 million on October 1, 2013; and

acquisition by MEMP of all the outstanding membership interests in WHT for a purchase price of approximately $200.0 million on March 28, 2013.

	For Year Ended December 31,		For Nine Months Ended September 30,	
	2013	2012	2014	2013
			(unaudited)	
Oil and natural gas sales	$ 230,751	$ 138,032	$ 300,931	$ 171,013
Lease operating	25,006	24,438	18,657	17,065
Exploration	1,226	7,337	1,213	1,137
Production and ad valorem taxes	9,362	7,576	10,494	8,563
Depreciation, depletion and amortization	87,043	62,636	107,496	62,605
Incentive unit compensation cost			969,390	19,069
Impairment of proved oil and natural gas properties	2,527	18,339		
General and administrative	81,758	38,414	29,301	22,466
(Gain) loss on commodity derivative instruments	(3,013)	(13,488)	(17,130)	(8,361)
(Gain) loss on sale of properties	(82,773)	(2)	3,057	(83,370)
Interest expense, net	27,349	12,802	(44,355)	(15,947)
Loss on extinguishment of debt			(37,248)	
Income tax benefit (expense)			(14,323)	(1,147)
Net income (loss)	82,243	(14,641)	(930,149)	114,628
Natural gas and oil revenue:				
Oil sales	$ 66,961	$ 35,264	$ 66,495	$ 50,683
NGL sales	53,881	36,611	67,539	37,311
Natural gas sales	109,909	66,157	166,897	83,019
Total natural gas and oil revenue	$ 230,751	$ 138,032	$ 300,931	$ 171,013
Production Volumes:				
Oil (MBbls)	665	369	689	498
NGLs (MBbls)	1,457	898	1,612	990
Natural gas (MMcf)	34,092	24,130	43,075	25,164
Total (MMcfe)	46,819	31,731	56,869	34,075
Average net production (MMcfe/d)	128.3	86.7	208.3	124.8
Average sales price:				

Oil (Bbl)	$ 100.76	$ 95.56	$ 96.60	$ 101.77
NGL (Bbl)	36.99	40.78	41.93	37.69
Natural gas (per Mcf)	3.22	2.74	3.87	3.30
Total (Mcfe)	$ 4.93	$ 4.35	$ 5.29	$ 5.02
Average unit costs per Mcfe:				
Lease operating expense	$ 0.53	$ 0.77	$ 0.33	$ 0.50
Production and ad valorem taxes	$ 0.20	$ 0.24	$ 0.18	$ 0.25
General and administrative expenses	$ 1.75	$ 1.21	$ 0.52	$ 0.66
Depletion, depreciation, and amortization	$ 1.86	$ 1.97	$ 1.89	$ 1.84

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

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

Oil and natural gas revenues were $230.8 million in 2013, an increase of $92.7 million from 2012. Production increased 15,088 MMcfe (approximately 48%) while the average realized sales price increased $0.58 per Mcfe. Production volume increases were primarily due to acquisitions and drilling activities in the Cotton Valley formation in North Louisiana and East Texas. The favorable volume variance contributed to a $65.6 million increase in revenues, and the favorable pricing variance contributed to a $27.1 million increase in revenues.

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

The $24.4 million increase in DD&A expense was primarily due to increased production volumes related to acquisitions and drilling activities in the Cotton Valley formation in North Louisiana and East Texas. Increased production volumes increased DD&A expense by $29.8 million, while a 6% decrease in the DD&A rate between periods decreased DD&A expense by $5.4 million. On a per Mcfe basis, DD&A expense decreased by $0.11 per Mcfe from 2012 to 2013. An increase in proved reserve volumes more than offset the impact of increases to the depletable cost base. Generally, if reserve volumes are revised up or down, then the DD&A rate per unit of production will change inversely. However, if the depletable base changes, then the DD&A rate moves in the same direction. Absolute or total DD&A, as opposed to the rate per unit of production, generally moves in the same direction as production volumes.

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

General and administrative expenses were $81.8 million in 2013, an increase of $43.3 million from 2012. The increase in general and administrative expenses was primarily due to growth in employees as a result of acquisitions and development activities and incentive unit compensation expense. General and administrative expenses during 2013 included recognition of approximately $43.3 million of compensation expense related to incentive unit payments to certain key management members of certain MRD LLC subsidiaries compared to approximately $9.5 million recorded in 2012.

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

Given the volatility of commodity prices, it is not possible to predict future changes in fair value or cash settlements that will ultimately be realized upon settlement of the open positions in future years. If commodity prices at settlement are lower than the prices of the settled positions, the derivative contracts 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 settled positions, the derivative contracts 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.

During 2013, BlueStone entered into an agreement with a publicly traded third party to sell its remaining interest in certain properties in the Mossy Grove Prospect in Walker and Madison Counties located in East

Texas and recognized a gain of $89.5 million. This gain was offset by a loss of $6.8 million recorded by Black Diamond on the sale of certain of its Wyoming oil and gas properties. During 2012, gains of less than $0.1 million were recognized by the MRD Segment.

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

Nine Months Ended September 30, 2014 Compared to the Nine Months Ended September 30, 2013

The MRD Segment recorded a net loss of $930.1 million during 2014 compared to net income of $114.6 million during 2013. The net loss recorded during 2014 was primarily due to compensation expense recognized associated with incentive units as discussed below.

Oil, natural gas and NGL revenues for 2014 totaled $300.9 million, an increase of $129.9 million compared with 2013. Production increased 22.8 Bcfe (approximately 67%) primarily due to drilling activities in North Louisiana and East Texas. The average realized sales price increased $0.27 per Mcfe primarily due to higher natural gas and NGL prices. The favorable volume and pricing variance contributed to an approximate $114.4 million and $15.5 million increase in revenues, respectively.

Lease operating expenses were $18.7 million and $17.1 million for 2014 and 2013, respectively. On a per Mcfe basis, lease operating expenses decreased to $0.33 for 2014 from $0.50 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 $107.5 million compared to $62.6 million for 2013, a $44.9 million increase primarily due to both an increase in the depletable cost base and increased production volumes related to drilling activities in North Louisiana and East Texas. Increased production volumes caused DD&A expense to increase by an approximate $41.9 million and the change in the DD&A rate between periods caused DD&A expense to decrease by an approximate $3.0 million.

Incentive unit compensation expense for 2014 was $969.4 million, of which $831.1 million related to WildHorse Resources incentive units, $137.3 million related to MRD Holdco incentive units, and $1.0 million related to BlueStone incentive units as previously discussed above. Incentive unit compensation expense of approximately $19.1 million was recorded by BlueStone 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 $29.3 million compared to $22.5 million for 2013. General and administrative expenses for 2014 included $1.5 million of compensation expense associated with the MRD LTIP and $1.6 million of acquisition-related costs. General and administrative expenses for 2013 included $1.7 million of acquisition-related costs. Increased salaries and employee headcount also contributed to increased general and administrative expenses between periods.

Net gains on commodity derivative instruments of $17.1 million were recognized during 2014, consisting of $4.9 million of cash settlement payouts offset by a $22.0 million increase in the fair value of open hedge positions. Net gains on commodity derivative instruments of $8.4 million were recognized during 2013, consisting of $9.1 million of cash settlement receipts offset by a $0.7 million decrease in the fair value of open hedge positions.

Net interest expense during 2014 was $44.4 million, including amortization of deferred financing fees of approximately $2.6 million and accretion of discount associated with the PIK notes of $0.6 million. Net interest expense during 2013 was $15.9 million, including amortization of deferred financing fees of approximately $1.7 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.

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During 2013, BlueStone entered into an agreement with a third party to sell its remaining interest in certain properties and recognized a gain of $90.1 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.

We are organized as a taxable C corporation and subject to federal and certain state income taxes. We recorded tax expense of $14.3 million in 2014 subsequent to our initial public offering.

MEMP Segment

The MEMP Segment s consolidated and combined results of operations for the years ended December 31, 2013 and 2012 and the nine months ended September 30, 2014 and 2013 presented below have been derived from our and our predecessor s consolidated and combined financial statements included elsewhere in this prospectus.

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

two separate third party acquisitions by MEMP of assets in East Texas in May and September 2012, respectively, for a combined net purchase price of approximately $126.9 million;

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;

multiple acquisitions of operated and non-operated interests in certain oil and natural gas properties primarily located in the Permian Basin for an aggregate net purchase price of $75.9 million;

the acquisition of certain oil and natural gas properties in the Eagle Ford trend from Alta Mesa Holdings, LP in March 2014 for an adjusted purchase price of $168.1 million; and

the completion of the MEMP Wyoming Acquisition on July 1, 2014 for an aggregate purchase price of approximately $911.7 million, including estimated customary post-closing adjustments.

	For Year Ended December 31, 2013	2012	For Nine Months Ended September 30, 2014 (unaudited)	2013
Oil & natural gas sales	$ 341,197	$ 255,608	$ 368,370	$ 249,844
Lease operating	88,893	80,116	93,367	64,922
Exploration	1,130	2,463	252	1,128
Production and ad valorem taxes	17,784	16,048	23,129	14,915
Depreciation, depletion and amortization	97,269	76,036	105,830	69,723
Impairment of proved oil and natural gas properties	54,362	10,532	67,181	50,310
General and administrative	43,495	30,342	31,760	33,411
(Gain) loss on commodity derivative instruments	(26,281)	(21,417)	28,710	(21,195)
(Gain) loss on sale of properties	(2,848)	(9,759)		(2,848)
Interest expense, net	41,901	20,436	(60,573)	(26,047)
Net income (loss)	20,268	46,518	(45,037)	9,359
Natural gas and oil revenue:				
Oil sales	$ 171,095	$ 145,103	$ 192,086	$ 127,436
NGL sales	51,215	26,647	48,958	35,202
Natural gas sales	118,887	83,858	127,326	87,206
Total natural gas and oil revenue	$ 341,197	$ 255,608	$ 368,370	$ 249,844
Production Volumes:				
Oil (MBbls)	1,764	1,519	2,056	1,307
NGLs (MBbls)	1,632	745	1,498	1,147
Natural gas (MMcf)	35,924	29,744	30,625	26,137
Total (MMcfe)	56,303	43,329	51,946	40,861
Average net production (MMcfe/d)	154.3	118.4	190.3	149.7
Average sales price:				
Oil (Bbl)	$ 96.98	$ 95.54	$ 93.45	$ 97.50
NGL (Bbl)	31.38	35.75	32.69	30.69
Natural gas (per Mcf)	3.31	2.82	4.16	3.34
Total (Mcfe)	$ 6.06	$ 5.90	$ 7.09	$ 6.11
Average unit costs per Mcfe:				
Lease operating expense	$ 1.58	$ 1.85	$ 1.80	$ 1.59
Production and ad valorem taxes	$ 0.32	$ 0.37	$ 0.45	$ 0.37
General and administrative expenses	$ 0.77	$ 0.70	$ 0.61	$ 0.82
Depletion, depreciation, and amortization	$ 1.73	$ 1.75	$ 2.04	$ 1.71

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

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

Oil and natural gas revenues were $341.2 million in 2013, an increase of $85.6 million from 2012. Production increased 12,974 MMcfe (approximately 30%) while the average realized sales price increased $0.16 per Mcfe. The favorable volume variance contributed to a $76.6 million increase in revenues, whereas the favorable pricing variance contributed to a $9.0

million decrease in revenues.

Lease operating expenses were $88.9 million in 2013, an increase of $8.8 million from 2012. Production and ad valorem taxes were $17.8 million in 2013, an increase of $1.7 million from 2012. Both lease operating expenses and production and ad valorem taxes increased primarily due to increased production volumes associated with properties acquired during both 2012 and 2013 and increased drilling activities.

The increase in DD&A expense was primarily due to increased production volumes related to acquisitions in 2012 and 2013 and increased drilling activities. Increased production volumes caused DD&A expense

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to increase by $22.8 million, while a 1% change in the DD&A rate between periods caused DD&A expense to decrease by $1.5 million. An increase in proved reserve volumes more than offset the impact of increases to the depletable cost base.

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

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

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

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

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

Nine Months Ended September 30, 2014 Compared to the Nine Months Ended September 30, 2013

A net loss of $45.0 million was generated for the nine months ended September 30, 2014, primarily due to impairment charges, as discussed below, and losses on commodity derivatives. Net income of $9.4 million was generated for the nine months ended September 30, 2013.

Oil, natural gas and NGL revenues for 2014 totaled $368.4 million, an increase of $118.5 million compared with 2013. Production increased 11.1Bcfe (approximately 27%), primarily from drilling activities and increased volumes from third party acquisitions. The average realized sales price increased $0.98 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 $67.7 million and $50.8 million increase in revenues, respectively.

Lease operating expenses were $93.4 million and $64.9 million for the nine months ended September 30, 2014 and 2013, respectively. On a per Mcfe basis, lease operating expenses increased to $1.80 for 2014 from $1.59 for 2013. During 2014, MEMP recorded $2.9 million of estimated environmental remediation expenses associated with its Permian and Wyoming oil and gas properties.

Production and ad valorem taxes for 2014 totaled $23.1 million, an increase of $8.2 million compared with 2013 primarily due to an increase in production volumes. On a per Mcfe basis, production and ad

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valorem taxes increased to $0.45 for 2014 from $0.36 for 2013 due to higher production tax rates on a per Mcfe basis for MEMP s Wyoming acquisition.

DD&A expense for 2014 was $105.8 million compared to $69.7 million for 2013, a $36.1 million increase primarily due to both an increase in the depletable cost base and increased production volumes related to third party acquisitions and MEMP s drilling program. Increased production volumes caused DD&A expense to increase by an approximate $18.9 million and the change in the DD&A rate between periods caused DD&A expense to increase by an approximate $17.2 million.

MEMP recognized $67.2 million of impairments in 2014 related primarily to certain properties in South Texas. The estimated future cash flows expected from these properties were compared to their carrying values and determined to be unrecoverable as a result of a downward revision of estimated proved reserves based on pricing terms specified to these properties and increased operating costs. During 2013, the MEMP Segment recorded impairments of $50.3 million. The impairments related to certain properties located in East Texas. The estimated future cash flows expected from these properties were compared to their carrying values and determined to be unrecoverable as a result of a downward revision of estimated proved reserves based on updated well performance data.

General and administrative expenses for 2014 were $31.8 million and included $5.4 million of non-cash unit-based compensation expense and $3.9 million of acquisition-related costs. General and administrative expenses for 2013 totaled $33.4 million and included $2.3 million of non-cash unit-based compensation expense and $3.4 million of acquisition-related costs. The $1.6 million decrease in general administrative expenses included a $5.8 million buyout of Tanos management during 2013 offset by increased salaries and employee count between periods.

Net losses on commodity derivative instruments of $28.7 million were recognized during 2014, consisting of $15.0 million of cash settlement payouts in addition to a $13.7 million decline in the fair value of open hedge positions. Net gains on commodity derivative instruments of $21.2 million were recognized during 2013, consisting of $14.1 million of cash settlement receipts, in addition to a $7.1 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 $60.6 million during 2014, including losses on interest rate swaps of approximately $0.9 million, amortization of deferred financing fees of approximately $2.9 million, and accretion of net discount associated with the senior notes of $1.3 million. Net interest expense totaled $26.0 million during 2013, including gains on interest rate swaps of $0.2 million and amortization of deferred financing fees of approximately $4.5 million. The increase in net interest expense is primarily the result of higher level of indebtedness during 2014 compared to 2013, including MEMP s 2022 Senior Notes.

Liquidity and Capital Resources

Although results are consolidated for financial reporting, the MRD and MEMP Segments operate with independent capital structures. With the exception of cash distributions paid to the MRD Segment by the MEMP Segment related to MEMP partnership interests held by MRD LLC, 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 equity. We expect that the cash needs of each of the MRD Segment and the MEMP Segment will continue to be met independently of each other with a combination of these funding sources.

MRD Segment

Historically, the primary sources of liquidity have been through borrowings under credit facilities, capital contributions from NGP and certain members of management, borrowings under a second lien term loan facility, issuance of senior notes, asset sales, including dropdowns to MEMP, and net cash provided by operating activities. The primary use of cash has been for the exploitation, development and acquisition of natural gas, NGLs 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. The future success in growing proved reserves and production will be highly dependent on the capital resources available. As of December 31, 2013, we had 1,582 identified gross potential horizontal well locations, which will take many years to develop. Additionally, the proved undeveloped reserves will require an estimated $1.3 billion of development capital over the next five years according to our reserve report as of December 31, 2013. A significant portion of this capital requirement will be funded out of operating cash flows. However, we may be required to generate or raise significant capital to conduct drilling activities on these identified potential well locations and to finance the development of proved undeveloped reserves.

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 or 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.

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 2014 development drilling activities. However, future cash flows are subject to a number of variables, including the level of natural gas production and prices, 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 September 30, 2014, our liquidity of $650.2 million consisted of $9.7 million of cash and cash equivalents and $640.5 million of available borrowings under our revolving credit facility. As of September 30, 2014, we had a working capital deficit balance of $17.8 million primarily due to the timing of accruals, which included accrued capital expenditures of $33.8 million offset by a net asset balance of $15.2 million of current derivative instruments.

Capital Budget

During 2013, we invested approximately $190 million of capital at the MRD Segment to drill 31 gross (21.3 net) wells. A substantial portion of our development program is focused on horizontal drilling of liquids rich wells in the Terryville Complex, where we spent approximately $163 million in capital expenditures to drill 15 gross (12.1 net) horizontal wells during 2013.

In 2014, we have budgeted a total of $351 million to drill and complete 39 gross (34 net) operated wells, which includes $268.7 million of capital expenditures related to drilling recompletions and capital workovers we made during the nine months ended September 30, 2014 (approximately 84% of which were made in the Terryville Complex, 8% of which were made in East Texas, and 8% of which were made in the Rockies). We expect to fund our 2014 development primarily from cash flows from operations. The majority of our drilling locations and our 2014 development program are focused on the Terryville Complex, where we plan to invest $304 million on drilling and completing 33 gross (29 net) horizontal wells and 3 gross (2.7 net) vertical wells. In the Terryville Complex, we plan to run six rigs for the remainder of 2014 targeting primarily our four primary zones within the Cotton Valley the Upper Red, Lower Red, Lower Deep Pink and Upper Deep Pink. Total vertical depth of these zones ranges from 8,200 to 11,200 feet.

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In our East Texas properties in the Joaquin Field, we plan to spend development capital of $29 million to drill 4 gross (4 net) horizontal wells targeting the Cotton Valley formation at vertical depths of 6,000 to 10,000 feet.

In our Rockies properties, we plan to spend $18 million of development capital, primarily in the Tepee Field in the Piceance Basin in Colorado focused on 2 gross (2 net) vertical wells.

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 included elsewhere in this prospectus.

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MRD Segment

	For Year Ended December 31, 2013	2012	For Nine Months Ended September 30, 2014	2013
	(unaudited)		(unaudited)	
Net cash provided by operating activities	$ 83,910	$ 84,172	$ 181,683	$ 90,118
Net cash provided by (used in) investing activities				
Acquisition of oil and natural gas properties	$ (67,098)	$ (83,055)	$	$ (67,098)
Additions to oil and gas properties	(198,340)	(165,203)	(267,848)	(130,064)
Additions to other property and equipment	(2,432)	(1,267)	(9,134)	(1,058)
Equity investments in MEMP Segment	(521)	(206)	(570)	(189)
Distributions received from MEMP Segment related to partnership interests	26,006	19,263	6,068	19,100
Decrease (increase) in restricted cash	(49,347)		49,946	
Proceeds from the sale of oil and gas properties to third parties	151,187		6,700	152,274
Proceeds from the sale of MEMP common units	135,012			
Other		(3)	(301)	653
Net cash provided by (used in) investing activities	$ (5,533)	$ (230,471)	$ (215,140)	$ (26,382)
Net cash provided by (used in) financing activities:				
Advances on revolving credit facilities	$ 174,400	$ 228,450	$ 1,139,800	$ 161,700
Payments on revolving credit facilities	(280,500)	(129,750)	(1,314,900)	(200,500)
Proceeds from issuance of senior notes			600,000	
Borrowings under second lien credit facility	325,000			325,000
Redemption of second lien credit facility			(328,282)	
Redemption of senior notes			(351,808)	
Deferred financing costs			(18,875)	(12,619)
Proceeds from the issuance of PIK notes	343,000			
Loan origination fees	(20,267)	(1,276)		
Purchase of noncontrolling interests in consolidated subsidiaries	(13,865)		(3,292)	
Proceeds from initial public offering			408,500	
Costs incurred in conjunction with initial public offering			(28,198)	
Contribution from NGP affiliates related to sale of properties			1,165	
Contribution from NGP affiliate		7,033		
Contributions from MEMP Segment	180,260	29,280	33,880	84,020
Distributions to noncontrolling interest	(7,446)		(325)	(7,531)
Distributions to MEMP Segment		(1,900)		
Distributions to NGP affiliates				
Distributions to Funds	(732,362)			(363,437)
Distributions to MRD Holdco			(59,803)	
Distribution to NGP affiliates related to purchase of assets			(66,693)	
Distribution to NGP affiliate related to sale of assets, net of cash received			(32,770)	
Distributions made by previous owners	(2,590)	(2,317)		(1,715)
Other cash transfers from MEMP Segment		3,751		
Other	(4,593)		213	(6,296)
Net cash provided by (used in) financing activities	$ (38,963)	$ 133,271	$ (21,388)	$ (21,378)

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

Operating Activities. Net cash flows provided by operating activities were $83.9 million in 2013 compared to $84.2 million in 2012. Although production volumes increased 15,088 MMcfe (approximately 48%), net cash flows from operating activities were impacted by $43.3 million of compensation expense recognized in 2013 related to incentive unit payments, which was an increase of $33.8 million from 2012.

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

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

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

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

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

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

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

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

Distributions to the Funds during 2013 were $732.4 million. From time to time, MRD LLC has made distributions of cash to the Funds. The timing and amount of these cash distributions is within the discretion of the board of managers of MRD LLC and is based, in part, upon available cash, the performance of its business, and other relevant factors. In 2013, substantially all of the cash distributed to the Funds was sourced from long term borrowings or sales of assets or equity in MEMP. The sources to fund these distributions primarily included $225.0 million from the WildHorse second lien term loan, $210.0 million from the December 2013 PIK notes, $63.8 million from the sale of properties to third parties, $125.0 million from the sale of properties to MEMP and $105.0 million from the sale of 7,061,294 MEMP common units that MRD LLC owned. Distributions to noncontrolling interests and previous owners totaled $15.9 million in 2013 compared to $2.3 million in 2012.

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Nine Months Ended September 30, 2014 Compared to the Nine Months Ended September 30, 2013

Operating Activities. Net cash flows provided by operating activities were $181.7 million during 2014 compared to $90.1 million during 2013. Production increased 22.8 Bcfe (approximately 67%) and average realized sales price increased $0.27 per Mcfe as previously discussed under Results of Operations MRD Segment. Cash paid for interest during 2014 was $35.5 million compared to $12.8 million during 2013. During 2014, compensation expense of approximately $26.7 million was paid in cash related to WildHorse Resources incentive units compared to $19.1 million in 2013 related to BlueStone units.

Investing Activities. Total cash used in investing activities was $215.1 million during 2014 compared to $26.4 million for the same period in 2013. Cash used for additions to oil and gas properties $267.8 million during 2014 compared to $130.1 million for the same period in 2013, which consisted primarily of drilling and completion activities in the Cotton Valley in North Louisiana and East Texas area. Additions to other property and equipment were $9.1 million which consisted primarily of computer hardware, software, and other leased office space build out during 2014. On April 30, 2013, WildHorse Resources purchased certain oil and gas properties and leases in Louisiana from a third party for approximately $67.1 million. Distributions of $6.1 million were received from MEMP primarily from the subordinated units owned by MRD LLC during 2014 compared to $19.1 million during 2013 received from MEMP primarily from the common and subordinated units owned by MRD LLC. On May 9, 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, subject to customary post-closing adjustments. 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. 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 $380.3 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 $175.1 million during 2014 compared to net repayments of $38.8 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 onetime 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 $584.9 million from the issuance of our MRD Senior Notes during the nine months ending September 30, 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

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$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 Unaudited Condensed Consolidated and Combined Financial Statements included under Item 1 of this quarterly report.

MEMP paid $33.9 million to WildHorse Resources in connection with MEMP s April 1, 2014 acquisition of certain oil and natural gas properties in East Texas. MEMP paid $55.4 million to WildHorse Resources in connection with MEMP s March 28, 2013 acquisition of all the outstanding equity interests in WHT. Tanos also distributed approximately $28.6 million to MRD LLC during 2013.

In connection with the our initial public offering, certain former management members of WildHorse Resources contributed their 0.1% membership interest in WildHorse Resources as well as their incentive units 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 Golden Energy s 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 $363.4 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. During 2013, substantially all of the cash distributed to the Funds was sourced from long term borrowings or sales of assets. The sources to fund these distributions primarily included $225.0 million from the WildHorse second lien term loan, $75.0 million from the sale of properties to MEMP, and approximately $63.4 million related to the sale of properties by BlueStone.

Deferred financing costs of approximately $18.9 million were incurred during 2014 compared to approximately $12.6 million during 2013.

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MEMP Segment

	For Year Ended December 31, 2013	2012	For Nine Months Ended September 30, 2014	2013
	(unaudited)		(unaudited)	
Net cash provided by operating activities	$ 193,697	$ 156,844	$ 183,777	$ 147,005
Net cash provided by (used in) investing activities:				
Acquisition of oil and natural gas properties	$ (38,664)	$ (277,623)	$ (1,083,167)	$ (37,828)
Additions to oil and gas properties	(161,675)	(107,789)	(189,990)	(127,449)
Additions to other property and equipment	(238)	(1,748)		(126)
Additions to restricted investments	(5,361)	(4,599)	(2,883)	(4,263)
Proceeds from the sale of oil and gas properties	4,525	34,521		4,525
Deposits for property acquisitions				(25,310)
Other		29		
Net cash provided by (used in) investing activities	$ (201,413)	$ (357,209)	$ (1,276,040)	$ (190,451)
Net cash provided by (used in) financing activities:				
Advances on revolving credit facilities	$ 958,355	$ 391,000	$ 1,325,000	$ 316,355
Payments on revolving credit facilities	(1,485,537)	(121,819)	(1,127,000)	(699,868)
Proceeds from the issuance of senior notes	688,563		492,425	397,563
Deferred financing costs	(20,908)	(2,225)	(11,409)	(11,218)
Contributions from previous owners	7,233	44,072		7,233
Contribution from NGP affiliate	2,013	38,125		2,013
Contribution from general partner	521	206	570	189
Contributions from MRD Segment		1,900		
Net proceeds from public equity offering	490,138	194,304	541,066	171,779
Distributions to partners	(96,643)	(34,436)	(107,070)	(62,888)
Distributions to MRD Segment	(180,260)	(29,280)	(33,880)	(84,020)
Distributions to NGP affiliates	(355,495)	(242,174)		
Distributions made by previous owners	(2,552)	(26,455)		(2,552)
Other cash transfers to MRD Segment		(3,751)		
Other	(9,013)	(646)		55
Net cash provided by (used in) financing activities	$ (3,585)	$ 208,821	$ 1,079,702	$ 34,641

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

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

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

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Various restricted investment accounts fund certain long-term contractual and regulatory asset retirement obligations and collateralize certain regulatory bonds associated with the offshore Southern California oil properties. For the years ended December 31, 2013 and 2012, additions to restricted investments were $5.4 million and $4.6 million, respectively.

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

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

MEMP generated total net proceeds of $490.1 million from two separate equity offerings in 2013 compared to $194.3 million in 2012. In March 2013, MEMP issued 9,775,000 common units to the public at an offering price of $18.35 per unit generating net proceeds of approximately $171.8 million. In October 2013, MEMP issued 16,675,000 common units to the public at an offering price of $19.90 per unit generating net proceeds of approximately $318.3 million. In December 2012, MEMP generated net proceeds of $194.3 million from a public offering of common units.

MEMP completed a private placement of 7.625% senior notes due 2021 (the Senior Notes) with two additional issuances during 2013. MEMP issued $300.0 million aggregate principal amount of the Senior Notes at 98.521% of par in April 2013, an additional $100.0 million aggregate principal amount at 102.0% of par in May 2013 and an additional $300.0 million aggregate principal amount at 97.0% of par in October 2013. Total proceeds, net of discounts, from the issuance of the Senior Notes were $688.6 million during 2013.

Distributions to partners were $96.6 million during the year ended December 31, 2013 compared to $34.4 million during the year ended December 31, 2012 due to increases in both declared distribution rates per unit and increases in the number of outstanding units. Distributions to the MRD Segment totaled $180.3 million in 2013 compared to $29.3 million in 2012. These distributions were primarily associated with the acquisition of assets by MEMP from the MRD Segment. Distributions to NGP affiliates were $355.5 million in 2013 compared to $242.2 million in 2012. The 2013 distribution was associated with the acquisition of assets by MEMP from certain affiliates of NGP in October 2013. The 2012 distribution was associated with the acquisition of assets located offshore Southern California from an affiliate of NGP.

The previous owners received contributions of $7.2 million during 2013 compared to $44.1 million during 2012. Distributions made by the previous owners totaled $2.6 million in 2013 compared to $26.5 million in 2012.

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

Nine Months Ended September 30, 2014 Compared to the Nine Months Ended September 30, 2013

Operating Activities. Key drivers of net operating cash flows are commodity prices, production volumes and operating costs. Net income decreased by $54.4 million as further discussed above under Results of Operations MEMP Segment, and net cash provided by operating activities increased by $36.8 million. Cash paid for interest during 2014 was $32.0 million compared to $10.1 million during 2013. Net cash provided by

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operating activities included $11.4 million period-to-period increase in cash flow attributable to the timing of cash receipts and disbursements related to operating activities during 2014 compared to 2013.

Investing Activities. Net cash used in investing activities during 2014 was $1.28 billion, of which $1.08 billion was used to acquire oil and natural gas properties from a third parties and $190.0 million was used for additions to oil and gas properties. Cash used in investing activities during 2013 was $190.4 million, of which $37.8 million was used to acquire oil and natural gas properties from a third parties and $127.4 million was used for additions to oil and gas properties. During the nine months ended September 30, 2013, we paid a deposit of $25.3 million related to the Cinco Acquisition. During the nine months ended September 30, 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.

Financing Activities. For the nine months ended September 30, 2014, MEMP issued a total of 24,840,000 common units generating gross proceeds of approximately $553.3 million offset by approximately $12.2 million of costs incurred in conjunction with the issuance of common units. The net proceeds from these issuances were primarily used to repay borrowings on MEMP s revolving credit facility. On March 25, 2013, MEMP issued 9,775,000 common units representing limited partner interests in the Partnership to the public at an offering price of $18.35 per unit 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.

Distributions to partners during 2014 were $107.1 million compared to $62.9 million during 2013, of which the MRD Segment received $6.1 million during 2014 compared to $19.1 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 distributed 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 1, 2014 acquisition of certain oil and natural gas properties in East Texas. MEMP paid $55.4 million to WildHorse Resources in connection with its March 28, 2013 acquisition of all of the outstanding equity interests in WHT and repaid $89.3 million of indebtedness under WHT s credit facility. Tanos also 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 $5.2 million from MRD LLC. Distributions made by MEMP s previous owners totaled $2.6 million in 2013.

MEMP had net payments of $276.0 million under its revolving credit facility during 2013. The Cinco Group had advances of $18.4 million under their credit facilities and repaid $36.6 million of outstanding borrowings during the nine months ending September 30, 2013. MEMP had borrowings of $1.33 billion under its revolving credit facility during 2014 that were used primarily to fund their acquisitions and drilling program. Deferred financing costs of approximately $11.4 million were incurred during 2014 compared to approximately $11.2 million during 2013.

Proceeds of $492.4 million from the issuances of the 2022 Senior Notes during 2014 were used to repay borrowings outstanding under MEMP s revolving credit facility.

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Debt Agreements MRD Segment

Revolving Credit Facility

On June 18, 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 an initial borrowing base of $725 million and aggregate elected commitments of $725 million. On October 3, 2014, the borrowing base and aggregate elected commitments was increased from $668.5 million to $725 million.

We are permitted to borrow under the revolving credit facility in an amount up to the least of (i) the face amount of our revolving credit facility, (ii) the borrowing base and (iii) the aggregate elected commitments. The revolving credit facility is reserve-based, and thus our borrowing base is primarily based on the estimated value of our oil, NGL and natural gas properties and our commodity derivative contracts as determined semi-annually by our lenders in their sole discretion. Our borrowing base is subject to redetermination on a semi-annual basis based on an engineering report with respect to our estimated oil, NGL and natural gas reserves, which will take into account the prevailing oil, NGL 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. In addition, we may, subject to certain conditions, increase our aggregate elected commitments in an amount not to exceed the then effective borrowing base on or following a scheduled redetermination of our borrowing base once before the next scheduled redetermination date. 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 future 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.

Borrowings under the revolving credit facility are secured by liens on substantially all of our properties, but in any event, not less than 80% of the total value of our oil and natural gas properties, and all of our equity interests in any future guarantor subsidiaries and all of our other assets including personal property. Additionally, borrowings bear interest, at our option, at either (i) the greatest of (x) the prime rate as determined by the administrative agent, (y) the federal funds effective rate plus 0.50%, and (z) the one-month adjusted LIBOR plus 1.0% (adjusted upwards, if necessary, to the next 1/100th of 1%), in each case, plus a margin that varies from 0.50% to 1.50% per annum according to the total commitment usage (which is the ratio of outstanding borrowings and letters of credit to the borrowing base then in effect), or (ii) the applicable LIBOR plus a margin that varies from 1.50% to 2.50% per annum according to the total commitment usage. The unused portion of the total commitments is subject to a commitment fee that varies from 0.375% to 0.50% per annum according to our total commitments usage.

The revolving credit facility requires maintenance of a ratio of Consolidated EBITDAX to Consolidated Net Interest Expense (as each term is determined under the revolving credit facility), which we refer to as the interest coverage ratio, of not less than 2.5 to 1.0, and a ratio of consolidated current assets to consolidated current liabilities, each as determined under the revolving credit facility, which we refer to as the current ratio, of not less than 1.0 to 1.0.

Additionally, the revolving credit facility contains various covenants and restrictive provisions that, among other things, limit our ability to incur additional debt, guarantees or liens; consolidate, merge or transfer all or substantially all of our assets; make certain investments, acquisitions or other restricted payments; modify certain material agreements; engage in certain types of transactions with affiliates; dispose of assets; incur commodity hedges exceeding a certain percentage of our production and prepay certain indebtedness.

Events of default under the revolving credit facility include, but are not limited to, failure to make payments when due, breach of any covenant continuing beyond the applicable cure period, default under any other material debt, change in management or change of control, bankruptcy or other insolvency event and certain material adverse effects on our business.

If we fail to perform our obligations under these and other covenants, 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.

MRD Senior Notes

The MRD Senior Notes will mature on July 1, 2022. Interest on the MRD Senior Notes will accrue from July 10, 2014 and will be payable semiannually on January 1 and July 1 of each year, commencing on January 1, 2015. The MRD Senior Notes are fully and unconditionally guaranteed on a senior unsecured basis by certain of our existing subsidiaries. The MRD Senior Notes and the guarantees of the MRD Senior Notes will rank equally with our and the guarantors existing and future senior indebtedness, will be effectively junior to all of our and the guarantors existing and future secured indebtedness (to the extent of the value of the assets securing such indebtedness), and senior in right of payment to all of our and the guarantors subordinated indebtedness. The MRD Senior Notes will be structurally subordinated to the indebtedness and other liabilities of our non-guarantor subsidiaries, including MEMP and its subsidiaries and MEMP GP.

The MRD Senior Notes are governed by an indenture dated as of July 10, 2014. The MRD Senior Notes are subject to optional redemption at prices specified in the indenture plus accrued and unpaid interest, if any, to the date of redemption. The Company may also be required to repurchase the MRD Senior Notes upon a change of control. The indenture contains customary covenants and restrictive provisions, many of which will terminate if at any time no default exists under the indenture and the MRD Senior Notes receive an investment grade rating from both of two specified ratings agencies. MEMP and its subsidiaries are not subject to these covenants. The indenture also provides for customary and other events of default. In the case of an event of default arising from certain events of bankruptcy or insolvency with respect to either the Company or the guarantors, all outstanding MRD Senior Notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of the then outstanding MRD Senior Notes may declare all the MRD Senior Notes to be due and payable immediately.

MRD LLC Revolving Credit Agreement (Terminated)

On July 13, 2012, MRD LLC entered into a two-year $50.0 million senior secured revolving credit facility with an initial borrowing base of $35.0 million. MRD LLC pledged 7,061,294 MEMP common units and 5,360,912 MEMP subordinated units as security under the credit facility as well as its oil and gas properties and certain other assets of MRD LLC. On November 20, 2012, MRD LLC entered into a first amendment to its credit agreement, which among other things: (i) increased the aggregate maximum credit to $1.0 billion (ii) increased the borrowing base to $120.0 million and (iii) extended the maturity date to November 20, 2016. On April 25, 2013, MRD LLC entered into a second amendment to its credit agreement, which among other things: (i) increased the borrowing base to $170.0 million and (ii) designated Tanos together with its consolidating subsidiaries as additional guarantors.

On October 1, 2013, Tanos and its consolidating subsidiaries were removed as guarantors and the borrowing base was reduced to $120.0 million. On November 1, 2013, MRD LLC entered into a third amendment to its credit agreement, which among other things: (i) designated Black Diamond together with its consolidating subsidiaries as additional guarantors, (ii) reduced the borrowing base to $100.0 million, and (iii) permitted second lien indebtedness. On November 22, 2013, the borrowing base was automatically reduced to $60.0 million upon MRD LLC s sale of 7,061,294 MEMP common units in a secondary offering. On December 18, 2013, indebtedness then outstanding under the revolving credit facility of $59.7 million and all accrued interest were paid off in full and the revolving credit facility was terminated in connection with the issuance of the PIK notes discussed below.

PIK Notes (Redeemed)

A redemption notice was delivered to the PIK notes trustee on June 16, 2014, which specified a redemption date of July 16, 2014 at a redemption price of 102% of the principal amount of the PIK notes plus accrued and unpaid interest thereon to the date of redemption. In connection with the closing of our initial public offering, we assumed the obligations of MRD LLC under the PIK notes indenture and the related debt security agreement. We irrevocably deposited with the PIK notes trustee approximately $360.0 million on June 27, 2014, which was an amount sufficient to fund the redemption of the PIK notes on the redemption date and to satisfy and discharge our obligations under the PIK notes and the related indenture. The discharge became effective upon the irrevocable deposit of the funds with the PIK notes trustee.

WildHorse Resources Revolving Credit Facility and Second Lien Facility (Terminated)

In connection with the closing of our initial public offering, the WildHorse Resources revolving credit facility and second lien term loan were repaid in full and terminated.

Black Diamond Revolving Credit Facility (Terminated)

On July 27, 2011, the Black Diamond entered into a second amended and restated revolving credit facility, which extended the maturity date of the original agreement to May 9, 2015. Borrowings under the revolving credit facility are collateralized by Black Diamond s oil and natural gas properties. On November 1, 2013, the Black Diamond revolving credit facility was terminated. There was no indebtedness outstanding or accrued interest payable on such date.

Debt Agreements MEMP Segment

MEMP Revolving Credit Facility

On December 14, 2011, Memorial Production Operating LLC (OLLC), a wholly-owned subsidiary of MEMP, entered into multi-year $1.0 billion senior secured revolving credit facility with an initial borrowing base of $300.0 million. A sixth amendment to the credit agreement was entered into on September 26, 2013, which among other things: (i) increased the facility from $1.0 billion to $2.0 billion and (ii) increased the borrowing base from $480.0 million to $920.0 million upon the closing of MEMP s $603.0 million acquisition that closed October 1, 2013. On October 10, 2013, borrowing base was automatically reduced by $75.0 million in conjunction with the issuance of additional senior notes as discussed below in accordance with the terms of the credit facility. A seventh amendment to the credit agreement was entered into on June 13, 2014, which among other things increased the borrowing base to $1.44 billion upon the closing of the MEMP Wyoming Acquisition. On

July 17, 2014, the borrowing base was automatically reduced by $125.0 million in conjunction with the issuance of the 2022 Senior Notes in accordance with the terms of the credit facility. Borrowings under the revolving credit facility are secured by liens on substantially all of MEMP s properties, but in any event, not less than 80% of the total value of MEMP s oil and natural gas properties, and all of MEMP s equity interests in OLLC and any future guarantor subsidiaries (other than San Pedro Bay Pipeline Company) and all of MEMP s other assets including personal property. Additionally, borrowings under the revolving credit facility bear interest, at MEMP s option, at: (i) the Alternative Base Rate defined as the greatest of (x) the prime rate as determined by the administrative agent, (y) the federal funds effective rate plus 0.50%, and (z) the one-month adjusted LIBOR plus 1.0% (adjusted upwards, if necessary, to the next 1/100th of 1%), in each case, plus a margin that varies from 0.50% to 1.50% per annum according to the borrowing base usage (which is the ratio of outstanding borrowings and letters of credit to the borrowing base then in effect), (ii) the applicable LIBOR plus a margin that varies from 1.50% to 2.50% per annum according to the borrowing base usage, or (iii) the applicable LIBOR Market Index plus a margin that varies from 1.75% to 2.75% per annum according to the borrowing base usage. The unused portion of the borrowing base will be subject to a commitment fee that varies from 0.375% to 0.50% per annum according to the borrowing base usage.

2021 Senior Notes

On April 17, 2013, MEMP and Finance Corp. completed a private placement of $300.0 million aggregate principal amount of 7.625% senior unsecured notes due 2021 (the Senior Notes). The Senior Notes were issued at 98.521% of par and are fully and unconditionally guaranteed (subject to customary release provisions) on a joint and several basis by all of the MEMP s subsidiaries (other than Finance Corp., which is co-issuer of the Senior Notes, and certain immaterial subsidiaries). On May 23, 2013, the Issuers issued an additional $100.0 million aggregate principal amount of the Senior Notes at 102% of par. The 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, commencing November 1, 2013. The Senior Notes are governed by an indenture. The Senior Notes are subject to optional redemption at prices specified in the indenture plus accrued and unpaid interest, if any. The Issuers may also be required to repurchase the Senior Notes upon a change of control. The indenture contains customary covenants and restrictive provisions, many of which will terminate if at any time no default exists under the indenture and the Senior Notes receive an investment grade rating from both of two specified ratings agencies. The indenture also provides for customary and other events of default. In the case of an event of default arising from certain events of bankruptcy or insolvency with respect to either of the Issuers, all outstanding Senior Notes will become due and payable immediately without further action or notice. If any other event of default occurs and is continuing, the trustee or the holders of at least 25% in principal amount of the then outstanding Senior Notes may declare all the Senior Notes to be due and payable immediately.

2022 Senior Notes

On July 17, 2014, the MEMP Issuers issued the 2022 Senior Notes as previously discussed under Significant Recent Developments MEMP Segment.

For additional information regarding the 2022 Senior Notes, see Note 8 of the Notes to Unaudited Condensed Consolidated and Combined Financial Statements included elsewhere in this prospectus.

Previous Owner Revolving Credit Facilities (Terminated)

On October 1, 2013, the debt balance then outstanding under the Boaz and Crown revolving credit facilities and all accrued interest was paid off in full and these revolving credit facilities were terminated. On October 1, 2013, the debt balance then outstanding under the Stanolind and Propel Energy revolving credit facilities and all accrued interest was paid off in full by MEMP on behalf of Stanolind and Propel Energy, respectively.

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Contractual Obligations

In the table below, we set forth MRD LLC s consolidated and combined contractual obligations as of December 31, 2013. 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.

During the nine months ended September 30, 2014, there were no significant changes in our consolidated and combined contractual obligations except for borrowings and repayments under revolving credit facilities, the redemption of the PIK notes, the repayment and termination of WildHorse Resources revolving and second lien credit facilities, the issuance of senior notes by both MRD and MEMP, and the assumption of a purchase commitment presented in the table below.

	Payments Due by Period (in thousands)				
Contractual Obligations	**Total**	**2014**	**2015 - 2016**	**2017 2018**	**Beyond 2018**
Revolving credit facility(1)					
MRD Segment	$ 203,100	$	$	$ 203,100	$
MEMP Segment	103,000			103,000	
Estimated interest payments(2)					
MRD Segment	20,242	4,671	9,342	6,229	
MEMP Segment	14,227	3,348	6,695	4,184	
Notes and Second Lien Term Loan(3)					
MRD Segment	973,500	59,700	119,400	794,400	
MEMP Segment	1,100,313	53,375	106,750	106,750	833,438
Asset retirement obligations(4)					
MRD Segment	12,150	90	1,818	2,775	7,467
MEMP Segment	99,619		1,878	6,373	91,368
Decommissioning Trust Agreement(5)					
MRD Segment					
MEMP Segment	12,392	2,042	10,350		
Operating leases					
MRD Segment	16,340	1,840	4,153	5,091	5,256
MEMP Segment	3,985	549	976	410	2,050
Compression services					
MRD Segment	583	572	11		
MEMP Segment	6,507	6,507			
Drilling services					
MRD Segment	20,323	20,323			
MEMP Segment					
Processing Plant Demand Fees					
MRD Segment	118,182	19,347	51,606	47,229	
MEMP Segment					
Total	$ 2,704,463	$ 172,364	$ 312,979	$ 1,279,541	$ 939,579

(1) Represents the scheduled future maturities of principal amounts outstanding for the periods indicated. See the Notes to the Consolidated and Combined Financial Statements included elsewhere in this prospectus 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, 2013. In calculating these amounts, we applied the weighted-average interest rate during 2013 associated with such debt. See the Notes to the Consolidated and Combined Financial Statements included elsewhere in this prospectus for the weighted-average variable interest rate charged during 2013 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, 2013.

(3) Represents the scheduled future interest payments and principal payments on the PIK notes, the Senior Notes and the WildHorse Resources second lien term loan. See the Notes to the Consolidated and Combined Financial Statements included elsewhere in this prospectus for information regarding debt agreements.

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(4) Asset retirement obligations represent estimated discounted costs for future dismantlement and abandonment costs. These obligations are recorded as liabilities on our December 31, 2013 balance sheet. See the Notes to the Consolidated and Combined Financial Statements included elsewhere in this prospectus for additional information regarding our asset retirement obligations.

(5) Pursuant to a Bureau of Ocean Energy Management decommissioning trust agreement, the Partnership is required to fund a trust account to comply with supplemental regulatory bonding requirements related to decommissioning obligations for the offshore Southern California production facilities. See the Notes to the Consolidated and Combined Financial Statements included elsewhere in this prospectus for additional information.

During the nine months ended September 30, 2014, MEMP assumed the following contractual obligation as a result of its Wyoming Acquisition as noted above (in thousands):

		Payment or Settlement due by Period			
Purchase commitment	**Total**	**Remainder 2014**	**2015 -2016**	**2017 -2018**	**Beyond 2018**
CO_2 minimum purchase commitment:					
Estimated payment obligation(1)	$ 62,103	$ 3,203	$ 24,323	$ 19,496	$ 15,081

(1) Represents firm agreement to purchase CO_2 volumes as of September 30, 2014.

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 use NSAI to prepare a reserve report as of December 31 of each year for a vast majority of our proved reserves and to prepare internal estimates of our proved reserves as of June 30 of each year.

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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.

Asset Retirement Obligations

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

Incentive Units

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

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

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

In connection with the closing of our initial public offering, certain former management members of WildHorse Resources contributed to us their incentive units in WildHorse Resources, as well as the remaining 0.1% of the membership interests in WildHorse Resources in exchange for approximately 42.3 million shares of our common stock and cash consideration of $30.0 million. See Note 12 of the Notes to Unaudited Condensed Consolidate and Combined Financial Statements included elsewhere in this prospectus 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 within general and administrative expenses, 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 Unaudited Condensed Consolidate and Combined Financial Statements included elsewhere in this prospectus for additional information.

Revenue Recognition

Revenue from the sale of natural gas and oil is recognized when title passes, net of royalties due to third parties. Natural gas and oil revenues are recorded using the sales method. Under this method, revenues are recognized based on actual volumes of natural gas and oil sold to purchasers, regardless of whether the sales are proportionate to our ownership in the property. An asset or a liability is recognized to the extent that we have an imbalance in excess of our proportionate share of the remaining recoverable reserves on the underlying properties.

Derivative Instruments

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

Income Tax

Our predecessor was organized as a pass-through entity for federal income tax purposes. As a result, members are responsible for federal income taxes on their share of our taxable income. Certain of our predecessor s consolidated subsidiaries are taxed as corporations and subject to federal income taxes. Our predecessor was also subject to the Texas margin tax and certain aspects of the tax make it similar to an income tax as the tax is assessed on 1% of taxable margin apportioned to operations in Texas. Deferred taxes arise due to temporary differences between the financial statement carrying value of existing assets and liabilities and their respective tax basis.

Our predecessor had to recognize the tax effects of any uncertain tax positions it may adopt if the position taken is more likely than not sustainable based on its technical merits. If a tax position meets such criteria, the tax effect that would be recognized by us would be the largest amount of benefit with more than a 50% chance of being realized. There were no uncertain tax positions that required recognition in the financial statements at December 31, 2013 or 2012.

Following our initial public offering, we are treated as a taxable C corporation and are subject to federal and certain state income taxes. Accordingly, a pro forma income tax provision has been disclosed as if our predecessor was a taxable corporation for the years ended December 31, 2013 and 2012. A pro forma effective tax rate of 36.06% and 35.39% was used for the years ended December 31, 2013 and 2012, respectively. If MRD LLC had affected the change in tax status on December 31, 2013, MRD LLC would have recognized a deferred tax liability of approximately $114.9 million primarily related to the tax basis of its long-lived assets being less than its book basis in those assets. MRD LLC would not have recognized any material deferred tax assets.

Unaudited Pro Forma Earnings Per Share

MRD LLC has presented pro forma earnings per share for the years ended December 31, 2013 and 2012. Pro forma net income (loss) per basic and diluted share was determined by dividing the pro forma net income (loss) by the number of common shares that were expected to be outstanding immediately following our initial public offering.

Off Balance Sheet Arrangements

As of September 30, 2014, we had no off balance sheet arrangements.

Recently Issued Accounting Pronouncements

For a discussion of recent accounting pronouncements that will affect us, see the Notes to the Consolidated and Combined Financial Statements included elsewhere in this prospectus.

Emerging Growth Company

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

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 hedging purposes, rather 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 and oil prices. Natural gas 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 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 and oil production through various transactions that fix the future 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. Additionally, we may enter into collars, whereby we receive

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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. These hedging activities are intended to support natural gas and oil prices at targeted levels and to manage our exposure to natural gas and oil price fluctuations. We do not enter derivative contracts for speculative trading purposes. Our revolving credit facility contains various covenants and restrictive provisions which, among other things, limit our ability to enter into commodity price hedges exceeding a certain percentage of production.

For additional information regarding the volumes of our production covered by commodity derivative contracts and the average prices at which production is hedged as of September 30, 2014, December 31, 2013 and December 31, 2012, see the Notes to the Consolidated and Combined Financial Statements included elsewhere in this prospectus as well as the tables below.

At September 30, 2014, the MRD Segment had the following open commodity positions:

	Remaining 2014	2015	2016	2017	2018
Natural Gas Derivative Contracts:					
Fixed price swap contracts:					
Average Monthly Volume (MMBtu)	4,540,000	2,250,000	1,670,000	1,270,000	1,500,000
Weighted-average fixed price	$ 4.18	$ 4.08	$ 4.18	$ 4.30	$ 4.30
Collar contracts:					
Average Monthly Volume (MMBtu)	730,000	1,580,000	1,100,000	1,050,000	
Weighted-average floor price	$ 4.11	$ 4.14	$ 4.00	$ 4.00	$
Weighted-average ceiling price	$ 5.15	$ 4.61	$ 4.71	$ 5.06	$
TGT Z1 basis swaps:					
Average Monthly Volume (MMBtu)	2,270,000	1,730,000	220,000	200,000	
Spread	$ (0.08)	$ (0.09)	$ (0.08)	$ (0.08)	$
Crude Oil Derivative Contracts:					
Fixed price swap contracts:					
Average Monthly Volume (Bbls)	56,000	33,500		9,500	7,625
Weighted-average fixed price	$ 94.43	$ 93.86	$	$ 87.62	$ 87.00
Collar contracts:					
Average Monthly Volume (Bbls)	12,000	2,000	27,000		
Weighted-average floor price	$ 86.67	$ 85.00	$ 80.00	$	$
Weighted-average ceiling price	$ 112.33	$ 101.35	$ 99.70	$	$
Put option contracts:					
Average Monthly Volume (Bbls)		26,000			
Weighted-average fixed price	$	$ 85.00	$	$	$
Weighted-average deferred premium	$	$ (3.80)	$	$	$
NGL Derivative Contracts:					
Fixed price swap contracts:					
Average Monthly Volume (Bbls)	184,000	151,000	148,500		
Weighted-average fixed price	$ 44.84	$ 41.61	$ 39.75	$	$

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At September 30, 2014, the MEMP Segment had the following open commodity positions:

	Remaining 2014	2015	2016	2017	2018	2019
Natural Gas Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (MMBtu)	2,580,200	2,605,278	2,692,442	2,450,067	2,160,000	1,914,583
Weighted-average fixed price	$ 4.34	$ 4.28	$ 4.40	$ 4.31	$ 4.51	$ 4.75
Collar contracts:						
Average Monthly Volume (MMBtu)	340,000	350,000				
Weighted-average floor price	$ 5.00	$ 4.62	$	$	$	$
Weighted-average ceiling price	$ 6.31	$ 5.80	$	$	$	$
Call spreads(1):						
Average Monthly Volume (MMBtu)	120,000	80,000				
Weighted-average sold strike price	$ 5.17	$ 5.25	$	$	$	$
Weighted-average bought strike price	$ 6.53	$ 6.75	$	$	$	$
Basis swaps:						
Average Monthly Volume (MMBtu)	2,830,000	2,940,000	1,635,000	300,000		
Spread	$ (0.09)	$ (0.12)	$ (0.06)	$ (0.05)	$	$
Crude Oil Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (Bbls)	283,452	314,281	332,813	326,600	312,000	160,000
Weighted-average fixed price	$ 95.83	$ 90.96	$ 85.83	$ 84.38	$ 83.74	$ 85.52
Collar contracts:						
Average Monthly Volume (Bbls)	23,000	5,000				
Weighted-average floor price	$ 82.83	$ 80.00	$	$	$	$
Weighted-average ceiling price	$ 105.31	$ 94.00	$	$	$	$
Basis swaps:						
Average Monthly Volume (Bbls)	134,000	97,500				
Spread	$ (4.32)	$ (7.07)	$	$	$	$
NGL Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (Bbls)	167,500	149,200	55,000			
Weighted-average fixed price	$ 43.13	$ 43.02	$ 39.28	$	$	$

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

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At December 31, 2013, the MRD Segment had the following open commodity positions:

	2014	2015	2016	2017
Natural Gas Derivative Contracts:				
Fixed price swap contracts:				
Average Monthly Volume (MMBtu)	1,190,000	880,000	670,000	520,000
Weighted-average fixed price	$ 4.10	$ 4.19	$ 4.32	$ 4.45
Collar contracts:				
Average Monthly Volume (MMBtu)	330,000	130,000		
Weighted-average floor price	$ 4.09	$ 4.00	$	$
Weighted-average ceiling price	$ 5.24	$ 4.64	$	$
Basis swaps:				
Average Monthly Volume (MMBtu)	270,000	180,000	220,000	200,000
Spread	$ (0.07)	$ (0.09)	$ (0.08)	$ (0.08)
Crude Oil Derivative Contracts:				
Fixed price swap contracts:				
Average Monthly Volume (Bbls)	18,000	6,000		
Weighted-average fixed price	$ 91.66	$ 88.50	$	$
Collar contracts:				
Average Monthly Volume (Bbls)	8,000	2,000		
Weighted-average floor price	$ 85.00	$ 85.00	$	$
Weighted-average ceiling price	$ 117.50	$ 101.35	$	$
NGL Derivative Contracts:				
Fixed price swap contracts:				
Average Monthly Volume (Bbls)	18,000			
Weighted-average fixed price	$ 64.27	$	$	$

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At December 31, 2013, the MEMP Segment had the following open commodity positions:

	2014	2015	2016	2017	2018	2019
Natural Gas Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (MMBtu)	2,575,458	2,145,278	2,342,442	2,230,067	2,060,000	1,814,583
Weighted-average fixed price	$ 4.34	$ 4.30	$ 4.42	$ 4.31	$ 4.52	$ 4.77
Collar contracts:						
Average Monthly Volume (MMBtu)	340,000	350,000				
Weighted-average floor price	$ 4.93	$ 4.62	$	$	$	$
Weighted-average ceiling price	$ 6.12	$ 5.80	$	$	$	$
Call spreads(1):						
Average Monthly Volume (MMBtu)	120,000	80,000				
Weighted-average sold strike price	$ 5.08	$ 5.25	$	$	$	$
Weighted-average bought strike price	$ 6.31	$ 6.75	$	$	$	$
Basis swaps:						
Average Monthly Volume (MMBtu)	2,822,083					
Spread	$ (0.09)	$	$	$	$	$
Crude Oil Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (Bbls)	136,444	148,281	142,313	130,600	122,000	40,000
Weighted-average fixed price	$ 95.82	$ 93.07	$ 86.85	$ 85.96	$ 85.62	$ 85.00
Collar contracts:						
Average Monthly Volume (Bbls)	23,000	5,000				
Weighted-average floor price	$ 82.83	$ 80.00	$	$	$	$
Weighted-average ceiling price	$ 105.31	$ 94.00	$	$	$	$
Basis swaps:						
Average Monthly Volume (Bbls)	57,292	57,500				
Spread	$ (9.21)	$ (9.73)	$	$	$	$
NGL Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (Bbls)	118,500	112,800				
Weighted-average fixed price	$ 36.23	$ 35.04	$	$	$	$

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

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At December 31, 2012, the MRD Segment had the following open commodity positions:

	2013	2014	2015
Natural Gas Derivative Contracts:			
Fixed price swap contracts:			
Average Monthly Volume (MMBtu)	961,000	540,000	210,000
Weighted-average fixed price	$ 4.08	$ 3.96	$ 4.09
Collar contracts:			
Average Monthly Volume (MMBtu)	661,000	430,000	130,000
Weighted-average floor price	$ 4.61	$ 4.18	$ 4.00
Weighted-average ceiling price	$ 5.56	$ 5.10	$ 4.64
Basis swaps:			
Average Monthly Volume (MMBtu)	230,000	230,000	390,000
Spread	$ (0.09)	$ (0.09)	$ (0.09)
Crude Oil Derivative Contracts:			
Fixed price swap contracts:			
Average Monthly Volume (Bbls)	6,000		
Weighted-average fixed price	$ 98.44	$	$
Collar contracts:			
Average Monthly Volume (Bbls)	22,750	14,000	2,000
Weighted-average floor price	$ 84.66	$ 87.86	$ 85.00
Weighted-average ceiling price	$ 108.89	$ 111.34	$ 101.35
NGL Derivative Contracts:			
Fixed price swap contracts:			
Average Monthly Volume (Bbls)	28,500	2,000	
Weighted-average fixed price	$ 54.12	$ 84.00	$

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At December 31, 2012, the MEMP Segment had the following open commodity positions:

	2013	2014	2015	2016	2017	2018
Natural Gas Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (MMBtu)	1,017,672	1,462,125	1,156,112	1,113,275	1,020,067	900,000
Weighted-average fixed price	$ 4.35	$ 4.38	$ 4.28	$ 4.53	$ 4.30	$ 4.75
Collar contracts:						
Average Monthly Volume (MMBtu)	1,014,000	340,000	350,000			
Weighted-average floor price	$ 4.76	$ 4.93	$ 4.62	$	$	$
Weighted-average ceiling price	$ 5.82	$ 6.12	$ 5.80	$	$	$
Call spreads(1):						
Average Monthly Volume (MMBtu)	430,000	120,000	80,000			
Weighted-average sold strike price	$ 4.59	$ 5.08	$ 5.25	$	$	$
Weighted-average bought strike price	$ 5.84	$ 6.31	$ 6.75	$	$	$
Basis swaps:						
Average Monthly Volume (MMBtu)	813,432	1,318,750				
Spread	$ (0.11)	$ (0.09)	$	$	$	$
Crude Oil Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (Bbls)	70,632	35,102	12,031	11,013	10,000	
Weighted-average fixed price	$ 103.32	$ 94.27	$ 90.29	$ 90.39	$ 88.30	$
Collar contracts:						
Average Monthly Volume (Bbls)	36,750	52,158	50,000	44,000	42,000	
Weighted-average floor price	$ 84.73	$ 90.51	$ 89.00	$ 85.00	$ 85.00	$
Weighted-average ceiling price	$ 108.07	$ 107.03	$ 103.31	$ 103.40	$ 99.00	$
Call contracts:						
Average Monthly Volume (Bbls)	10,000					
Weighted-average fixed price	$ 115.00	$	$	$	$	$
NGL Derivative Contracts:						
Fixed price swap contracts:						
Average Monthly Volume (Bbls)	30,805	16,300				
Weighted-average fixed price	$ 53.19	$ 58.91	$	$	$	$

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

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Interest Rate Risk

Periodically, we enter into interest rate swaps to mitigate exposure to market rate fluctuations by converting variable interest rates such as those in our credit agreement to fixed interest rates. See the Notes to the Consolidated and Combined Financial Statements included elsewhere in this prospectus for additional information regarding fixed-for-floating interest rate swap open positions as of September 30, 2014, December 31, 2013 and December 31, 2012 as well as the tables below.

At September 30, 2014, we had the following interest rate swap open positions:

Credit Facility	**Remaining 2014**	**2015**	**2016**
MEMP:			
Average Monthly Notional (in thousands)	$ 248,333	$ 280,833	$ 150,000
Weighted-average fixed rate	1.299%	1.416%	1.193%
Floating rate	1 Month LIBOR	1 Month LIBOR	1 Month LIBOR

At December 31, 2013, we had the following interest rate swap open positions:

Credit Facility	**2014**	**2015**	**2016**
MEMP:			
Average Monthly Notional (in thousands)	$ 173,958	$ 280,833	$ 150,000
Weighted-average fixed rate	1.306%	1.416%	1.193%
Floating rate	1 Month LIBOR	1 Month LIBOR	1 Month LIBOR
WildHorse Resources:			
Average Monthly Notional (in thousands)	$ 118,750	$ 100,000	$
Weighted-average fixed rate	0.773%	0.758%	
Floating rate	1 Month LIBOR	1 Month LIBOR	

At December 31, 2012, we had the following interest rate swap open positions:

Credit Facility	**2013**	**2014**	**2015**	**2016**
MEMP:				
Average Monthly Notional (in thousands)	$ 162,500	$ 150,000	$ 150,000	$ 150,000
Weighted-average fixed rate	1.148%	1.193%	1.193%	1.193%
Floating rate	1 Month LIBOR	1 Month LIBOR	1 Month LIBOR	1 Month LIBOR
WildHorse Resources:				
Average Monthly Notional (in thousands)	$ 150,667	$ 118,750	$ 100,000	$
Weighted-average fixed rate	0.779%	0.773%	0.758%	
Floating rate	1 Month LIBOR	1 Month LIBOR	1 Month LIBOR	
Tanos:				
Average Monthly Notional (in thousands)	$ 30,000	$	$	$
Weighted-average fixed rate	1.362%			
Floating rate	1 Month LIBOR			
WHT:				
Average Monthly Notional (in thousands)	$ 75,000	$ 25,000	$	$

Weighted-average fixed rate	1.510%	1,510%		
Floating rate	1 Month LIBOR	1 Month LIBOR		
			$	
Previous Owners:				
Average Monthly Notional (in thousands)	$ 11,500	$ 5,750		$
Weighted-average fixed rate	0.500%	0.500%	$	
Floating rate	1 Month LIBOR	1 Month LIBOR		

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Counterparty and Customer Credit Risk

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

By using derivative instruments that are not traded on an exchange to hedge exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates the credit risk. To minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market-makers. The creditworthiness of our counterparties is subject to periodic review. As of September 30, 2014, our derivative contracts are with major financial institutions, certain of which are also lenders under our revolving credit facilities. See the Notes to the Consolidated and Combined Financial Statements included elsewhere in this prospectus for additional information.

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

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BUSINESS

We have two reportable business segments, both of which are engaged in the acquisition, exploitation, development and production of oil and natural gas properties:

- MRD reflects the combined operations of the Company, MRD LLC, WildHorse Resources and its previous owners, Classic and Classic GP, Black Diamond, BlueStone, Beta Operating and MEMP GP.

- MEMP reflects the combined operations of MEMP, its previous owners, and historical dropdown transactions that occurred between MEMP and other MRD LLC consolidating subsidiaries.

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 limited partner interests. As a result, our financial statements and notes thereto included elsewhere in this prospectus consolidate MEMP s business and assets with ours. However, 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. See MEMP for information regarding MEMP s business and assets. In addition, because BlueStone, MRD Royalty, MRD Midstream and Classic Pipeline were not included in the assets that MRD LLC contributed to us in connection with the restructuring transactions, unless stated otherwise, the information in this section does not include BlueStone, MRD Royalty, MRD Midstream or Classic Pipeline.

We are an independent natural gas and oil company focused on the exploitation, development, and acquisition of natural gas, NGL and oil properties with a majority of our activity in the Terryville Complex of North Louisiana, where we are targeting overpressured, liquids-rich natural gas opportunities in multiple zones in the Cotton Valley formation. As of December 31, 2013, our total leasehold position was 347,458 gross (205,818 net) acres, of which 60,041 gross (51,522 net) acres are in what we believe to be the core of the Terryville Complex. We are focused on creating shareholder value primarily through the development of our sizeable horizontal inventory.

MEMP 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 principally located in East Texas/North Louisiana, the Rockies, South Texas, the Permian 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. MEMP is focused on generating stable cash flows, to allow MEMP to make quarterly cash distributions to its unitholders and, over time, to increase those quarterly cash distributions.

MRD

Overview

As of December 31, 2013, we had 1,582 gross (1,091 net) identified horizontal drilling locations, of which 1,431 gross (994 net) identified horizontal drilling locations are located in the Terryville Complex. These total gross identified horizontal drilling locations represent an inventory of over 42 years based on our expected 2014 drilling program. We believe our inventory to be repeatable and capable of generating high returns based on the extensive production history in the area, the results of our horizontal wells drilled to date, and the consistent reservoir quality across multiple target formations. As of December 31, 2013, we had estimated proved, probable and possible reserves of approximately

1,126 Bcfe, 800 Bcfe and 1,711 Bcfe, respectively. As of such date, we operated 98% of our proved reserves, 71% of which were natural gas. For the nine months ended September 30, 2014, 56% of our pro forma MRD Segment revenues were attributable to natural gas production, 22% to NGLs and 22% to oil. For the nine months ended September 30, 2014, we generated pro forma MRD Segment Adjusted EBITDA of $259 million and pro forma net loss of $914 million, and made pro forma capital expenditures of

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$268 million. For the year ended December 31, 2013, we generated pro forma MRD Segment Adjusted EBITDA of $159 million and pro forma net loss of $2.9 million, and made pro forma total capital expenditures of $203 million. Please see Summary Historical Consolidated and Combined Pro Forma Financial Data Adjusted EBITDA for an explanation of the basis for the pro forma presentation and our use of Adjusted EBITDA to measure the MRD Segment s profitability.

Our average net daily production for the nine months ended September 30, 2014 was approximately 208 MMcfe/d (approximately 76% natural gas, 17% NGLs and 7% oil) and our reserve life was 14.8 years. The Terryville Complex represented 84% of our total net production for the nine months ended September 30, 2014. As of December 31, 2013, we produced from 95 horizontal wells and 800 vertical wells. Since January 1, 2014, in the Terryville Complex we have completed and brought online 21 horizontal wells through September 30, 2014, bringing our total number of producing horizontal wells to 41 in our primary formations.

The following chart provides information regarding our production growth and the increasing proportion of our horizontal well production since the beginning of 2012.

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. To date, operators have drilled over 600 horizontal Cotton Valley wells. Some large, analogous redevelopment projects in the Cotton Valley include the Nan-Su-Gail Field in Freestone County, East Texas, where over 40 horizontal wells have been drilled by operators such as Devon Energy Corporation and Marathon Oil Corporation, and the Carthage Complex in Panola County, East Texas, where operators such as ExxonMobil Corporation, BP America, Memorial Production Partners LP and Anadarko Petroleum Corporation have drilled over 153 horizontal wells.

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Cotton Valley Terryville Complex Horizontal Redevelopment

We are currently engaged in the horizontal redevelopment of the Terryville Complex in Lincoln Parish, Louisiana utilizing horizontal drilling and completion techniques similar to those employed at the Nan-Su-Gail Field, Carthage Complex in East Texas and other major resource plays across the United States. We have assembled a largely contiguous acreage position in the Terryville Complex of approximately 60,041 gross (51,522 net) acres as of December 31, 2013. The majority of our current and planned development is focused in and around what we believe to be the core of the Terryville Complex.

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 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. We intend to dedicate approximately $304 million of our $351 million drilling and completion budget in 2014 to develop multiple zones within the Terryville Complex, where we expect to drill 33 gross (29 net) horizontal wells and 3 gross (2.7 net) vertical wells. Our horizontal redevelopment program in the Terryville Complex will be focused on increasing our well performance and recoveries.

Within the Terryville Complex, as of December 31, 2013, we had 945 Bcfe, 688 Bcfe and 1,643 Bcfe of estimated proved, probable and possible reserves, respectively, and a drilling inventory consisting of 1,431 gross (994 net) identified horizontal drilling locations, including 91 gross (72 net) drilling locations to which we have attributed proved undeveloped reserves as of December 31, 2013. Since initiating our horizontal drilling program in 2011, we have drilled 44 gross (38 net) horizontal wells. Within the Terryville Complex, on a proved reserves basis, we operate approximately 99% of our existing acreage and hold an average working interest of approximately 74% across our acreage. Our high operating control allows us to more efficiently and economically manage the redevelopment of this extensive resource.

We believe seismic data, as well as information gathered from the results of our existing 275 vertical and 46 horizontal wells throughout the field, support the existence of at least ten stacked pay zones across the Terryville Complex. Our redevelopment program currently targets four of the stacked 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 400 to 890 feet across our acreage position. We believe the overpressured nature of this section of the Cotton Valley formation is highly productive when accessed through horizontal drilling and fracture stimulation technologies. These qualities, when combined with the liquids-rich nature of the natural gas, high initial rates of production and competitive well costs, produce what we believe to be amongst the highest rate of return wells in the nation. Further, there are additional opportunities for redevelopment in the zones above the four main zones. NSAI has audited over $1 billion PV-10 and 677 Bcfe in our possible reserve category as of December 31, 2013 for the redevelopment of these additional zones. Please see Reserves.

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Our well results have shown consistency in initial production, decline rates and estimated ultimate recovery. The consistency of these results gives us confidence that the full-scale redevelopment of the Terryville Complex that we began in 2013 will continue to be successful. The table below details certain information on estimated ultimate recoveries and production on a gross basis for our 41 existing horizontal wells currently producing from our four primary target zones in the Terryville Complex to the extent such data is available as of the dates and for the periods presented below. The wells below highlight the consistency of our drilling results in the four primary target zones in which we plan to focus our future development activity.

	Lateral	Producing Wells EUR(1)				EUR			Cumulative Production				Gross Wellhead Flow Rates After Processing (MMcfe/d)(2)(3)				
Well Name	Length (Feet)	(Bcfe)	%Gas	%NGL	%Oil	Bcfe/ 1,000	First Production	Days Producing	(Bcfe)	%Gas	%NGL	%Oil	0-30	0-90	91-180	181-360	D&C ($MM)
Upper Red Zone																	
LD Barnett 23H-2	4,015	12.3	69%	27%	4%	3.1	1/30/2012	975	5.0	71%	24%	5%	14.5	12.0	7.7	5.6	6.7
Colquitt 20 17H-1	4,357	11.5	79%	18%	2%	2.6	7/30/2012	793	4.3	81%	17%	2%	17.5	12.6	7.2	5.1	7.8
Dowling 22 15H-1	5,376	9.4	78%	20%	2%	1.8	9/22/2012	739	5.7	80%	18%	3%	16.3	15.6	11.1	8.2	8.8
Nobles 13H-1	4,216	9.1	67%	24%	10%	2.1	11/17/2012	683	4.6	65%	22%	13%	21.5	16.7	9.9	6.5	7.8
Sidney McCullin 16 21H-1	4,604	13.8	75%	21%	3%	3.0	1/19/2013	620	5.0	81%	16%	3%	17.4	14.2	10.8	8.4	8.1
Wright 14 11 HC-1	5,250	11.9	66%	27%	7%	2.3	5/27/2013	492	5.5	64%	28%	8%	19.6	18.1	16.1	8.4	8.8
BF Fallin 22 15H-1	5,122	12.3	72%	24%	4%	2.4	6/17/2013	471	3.9	74%	22%	4%	14.8	13.7	11.8	5.9	7.5
Dowling 20 17H-1	4,327	9.0	73%	25%	3%	2.1	7/22/2013	436	2.6	77%	20%	3%	15.2	11.0	5.7	4.5	10.7
Gleason 31H-1	3,692	2.4	91%	9%	0%	0.7	8/12/2013	415	0.6	90%	10%	0%	2.9	2.3	1.6	1.2	9.5
Burnett 26H-1	2,405	5.5	71%	25%	4%	2.3	9/22/2013	374	1.2	71%	24%	5%	6.9	5.6	3.5	2.4	6.9
Drewett 17 8H-1	4,010	15.6	66%	25%	10%	3.9	11/13/2013	322	3.9	61%	26%	13%	22.1	18.6	11.9		7.7
Wright 13 12 HC-2	6,009	24.0	69%	22%	10%	4.0	12/21/2013	284	4.6	76%	11%	13%	22.7	19.6	16.3		8.5
LA Minerals 15 22H-2	5,814	17.3	73%	25%	3%	3.0	1/21/2014	253	3.4	76%	22%	3%	17.8	16.1	13.4		8.8
Wright 13 24 HC-3	6,606	20.9	74%	23%	3%	3.2	4/14/2014	170	3.4	85%	11%	4%	30.3	24.6			10.8
Wright 13 24 HC-1	6,678	15.5	71%	20%	8%	2.3	4/14/2014	170	2.8	77%	12%	11%	25.0	20.4			11.8
TL McCrary 14 11 HC-5	5,875	30.0	71%	24%	6%	5.1	4/14/2014	170	3.0	81%	11%	8%	22.9	23.3			10.2
LA Minerals 19 30 HC-2	6,912	15.1	75%	24%	2%	2.2	5/29/2014	125	2.3	85%	13%	2%	25.1	20.4			10.8
LA Minerals 19 30 HC-1	6,519	19.6	75%	23%	1%	3.0	6/1/2014	122	2.0	85%	13%	2%	21.5	17.7			11.6
Werner 29H-1	3,410	4.7	75%	23%	2%	1.4	8/13/2014	49	0.4	84%	13%	2%	8.6				11.0
Werner 29 32 5 HC-1	6,810	9.7	74%	23%	3%	1.4	8/13/2014	49	0.8	84%	13%	3%	18.4				10.4
Werner 29 32 5 HC-2	8,300	16.5	75%	23%	2%	2.0	8/13/2014	49	1.2	84%	13%	3%	26.1				12.2
Temple 8H-1	2,403	6.3	77%	23%	0%	2.6	8/24/2014	38	0.4	93%	7%	0%	12.7				9.6
Temple 8 17 HC-1	6,210	2.9	76%	23%	1%	0.5	8/29/2014	33	0.3	92%	7%	1%	8.4				11.9
TL McCrary 14 11 HC-2	4,401	NA					9/25/2014	6	0.1								7.7
TL McCrary 14 11 HC-4	4,810	NA					9/25/2014	6	0.0								9.0
Lower Red Zone																	
TL McCrary 14H-1	4,544	12.7	70%	27%	4%	2.8	5/1/2012	883	4.5	73%	23%	4%	14.4	11.7	8.3	5.4	7.7
Nobles 13H-2	4,060	5.6	66%	23%	11%	1.4	11/17/2012	683	3.3	68%	22%	10%	16.0	11.9	8.2	5.2	7.8
LA Methodist Orphanage 14H-1	3,637	9.5	69%	24%	7%	2.6	2/15/2013	593	4.0	69%	23%	8%	13.9	13.0	9.7	6.3	9.1

Dowling 21 16H-1	4,590	8.4	78%	21%	1%	1.8	3/18/2013	562	3.0	84%	15%	2%	13.0	10.1	6.5	4.5	6.6
Drewett 17 8H-2	3,700	4.2	66%	25%	9%	1.1	11/13/2013	322	1.2	63%	27%	11%	8.7	6.2	3.2		7.0
Wright 13 12 HC-1	5,409	9.4	70%	21%	9%	1.7	12/21/2013	284	2.2	76%	11%	13%	14.7	11.4	7.2		9.3
LA Minerals 15 22H-1	5,926	8.1	71%	24%	5%	1.4	1/21/2014	253	1.9	73%	21%	5%	13.8	10.9	6.4		7.8
Wright 13 24 HC-4	6,518	15.1	74%	23%	3%	2.3	4/14/2014	170	2.6	85%	11%	4%	25.7	19.6			13.4
LA Minerals 19 30 HC-3	5,356	2.5	76%	21%	3%	0.5	5/29/2014	125	0.6	84%	13%	3%	8.8	5.9			12.1
LA Minerals 19 30 HC-4	6,469	3.5	77%	21%	2%	0.5	6/1/2014	122	0.9	85%	13%	2%	13.6	8.5			13.8
TL McCrary 14 11 HC-1	4,010	NA					9/25/2014	6	0.0								8.9
TL McCrary 14 11 HC-3	4,620	NA					9/25/2014	6	0.0								8.3
Lower Deep Pink Zone																	
LA Methodist Orphanage 14H-2	3,550	6.1	68%	23%	9%	1.7	2/15/2013	593	3.5	67%	22%	11%	14.2	11.6	7.6	5.7	6.1
Wright 13 12 HC-4	5,010	5.8	69%	21%	10%	1.2	12/21/2013	284	1.6	75%	11%	13%	11.8	8.8	4.8		7.0
Wright 13 12 HC-3	5,706	5.4	71%	20%	8%	0.9	12/21/2013	284	1.6	77%	12%	11%	12.5	9.3	5.0		7.4
Upper Deep Pink Zone																	
Werner 29 32 5 HC-3	6,679	3.1	73%	22%	4%	0.5	8/13/2014	49	0.3	81%	13%	6%	7.2				10.1
Averages(4)																	
All Wells	**5,071**	**10.7**	**73%**	**23%**	**5%**	**2.1**		**319**	**2.4**	**78%**	**17%**	**6%**	**16.1**	**13.6**	**8.4**	**5.6**	**9.2**
Upper Red	**5,125**	**12.8**	**73%**	**23%**	**4%**	**2.5**		**314**	**2.7**	**79%**	**16%**	**5%**	**17.7**	**15.7**	**9.8**	**5.6**	**9.4**
Lower Red	**4,903**	**7.9**	**72%**	**23%**	**5%**	**1.6**		**334**	**2.0**	**76%**	**18%**	**6%**	**14.3**	**10.9**	**7.1**	**5.4**	**9.3**
Lower Deep Pink	**4,755**	**5.8**	**69%**	**21%**	**9%**	**1.3**		**387**	**2.2**	**73%**	**15%**	**12%**	**12.8**	**9.9**	**5.8**	**5.7**	**6.8**
Upper Deep Pink	**6,679**	**3.1**	**73%**	**22%**	**4%**	**0.5**		**49**	**0.3**	**81%**	**13%**	**6%**	**7.2**				**10.1**

(1) EUR represents the Estimated Ultimate Recovery or sum of total gross remaining proved reserves attributable to each location in our recent reserve report and cumulative sales from such location. EUR is shown on a combined basis for oil/condensates, gas and NGLs, after the effects of processing.

(2) Production data is as of September 30, 2014 and shown gross on a combined basis after the effects of processing.

(3) Periodic flow rates start on day 4, with days 1 through 3 used to allow clean up associated with well completion. The 30-day flow rates therefore start on day 4 and continue 30 days to day 33 and the 90-day flow rates go from day 4 to day 93.
(4) We also have five horizontal producing wells outside of the four primary target zones. These averages do not include such wells.

Cotton Valley Terryville Complex Proved Reserves Update

As of September 30, 2014, within the core Terryville Complex, we had proved reserves of 849 Bcfe based on our recent reserve report, and an aggregate drilling inventory of 1,411 gross identified drilling locations, taking into account drilling activity during the first nine months of 2014. The PV-10 of our proved reserves within the Terryville Complex as of September 30, 2014 was $1.6 billion. PV-10 is a non-GAAP financial measure and differs from standardized measure, the most directly comparable GAAP financial measure. Please see Reserves. SEC pricing for natural gas and oil used in calculating the PV-10 of such proved reserves as of September 30, 2014 was $4.23 per Mcf and $95.56 per Bbl, respectively, based on the unweighted average of the first-day-of-the-month prices for each of the twelve months preceding September 2014.

East Texas

We own and operate approximately 54,337 gross (42,894 net) acres as of December 31, 2013 in Texas, where we are currently producing primarily from the Cotton Valley, Travis Peak and Bossier formations and targeting the Cotton Valley formation for future development. From January 1, 2011 through December 31, 2013, we have drilled and completed 28 gross (10.3 net) wells and are operating one rig in East Texas as of December 31, 2013. In 2014, we plan to invest $29 million to drill 4 gross (4 net) wells in East Texas in the Joaquin Field of Panola and Shelby Counties. As of December 31, 2013, we had approximately 108 gross identified horizontal drilling locations in East Texas, including 54 gross (43 net) drilling locations to which we have attributed proved undeveloped reserves as of December 31, 2013. For the nine months ended September 30, 2014, our average net daily production from our East Texas properties was 27 MMcfe/d, of which 75% was natural gas. Within our East Texas properties, on a proved reserves basis, we operate approximately 94% of our existing properties.

Rockies

We own approximately 162,375 gross (66,191 net) acres as of December 31, 2013 in our Rockies region and for the nine months ended September 30, 2014 our average net daily production from this region was 6 MMcfe/d. In 2014, we plan to invest $18 million to complete 2 gross (2 net) vertical wells in the Tepee Field of the Piceance Basin targeting the Mancos and Williams Fork formations. As of December 31, 2013, we had approximately 174 gross identified vertical drilling locations in the Tepee Field in our Rockies properties.

Reserves

Our estimates of proved reserves are prepared by NSAI, and our estimates of probable and possible reserves are prepared by our management and audited by NSAI. As of December 31, 2013, we had 1,126 Bcfe, 800 Bcfe and 1,711 Bcfe of estimated proved, probable and possible reserves, respectively. As of this date, our proved reserves were 71% gas and 29% NGLs and oil. Additionally, the PV-10 of our proved reserves was $1,469 million, the PV-10 for our probable reserves was $1,052 million and the PV-10 for our possible reserves was $2,386 million. The following table provides summary information regarding our estimated proved, probable and possible reserves data by area based on our reserve report as of December 31, 2013 and our average net daily production by area for the nine months ended September 30, 2014:

	Proved Total (Bcfe)	% Gas	% Developed	Proved PV-10 (in millions)(1)	Probable Total (Bcfe)(2)	Probable PV-10 (in millions)(1)	Possible Total (Bcfe)(2)	Possible PV-10 (in millions)(1)	Average Net Daily Production (MMcfe/d)
Terryville Complex	945	71%	33%	$ 1,341	688	$ 1,032	1,643	$ 2,383	175
East Texas	175	75%	29%	110	109	18	66	3	27
Rockies	6	49%	100%	18	2	2	2	1	6
Total	1,126	71%	33%	$ 1,469	800	$ 1,052	1,711	$ 2,386	208

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(1) In this prospectus, we have disclosed our PV-10 based on our reserve report. PV-10 is a non-GAAP financial measure and represents the period-end present value of estimated future cash inflows from our natural gas and crude oil reserves, less future development and production costs, discounted at 10% per annum to reflect timing of future cash flows and using SEC pricing assumptions in effect at the end of the period. SEC pricing for natural gas and oil of $3.67 per Mcf and $93.42 per Bbl was based on the unweighted average of the first-day-of-the-month prices for each of the twelve months preceding December 2013. PV-10 differs from standardized measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes. Moreover, GAAP does not provide a measure of estimated future net cash flows for reserves other than proved reserves. Because PV-10 estimates of probable and possible reserves are more uncertain than PV-10 and standardized estimates of proved reserves, but have not been adjusted for risk due to that uncertainty, they may not be comparable with each other. Nonetheless, we believe that PV-10 estimates for reserve categories other than proved present useful information for investors about the future net cash flows of our reserves in the absence of a comparable GAAP measure such as standardized measure. Because of this, PV-10 can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. In addition, investors should be cautioned that estimates of PV-10 for probable and possible reserves, as well as the underlying volumetric estimates, are inherently more uncertain of being recovered and realized than comparable measures for proved reserves, and that the uncertainty for possible reserves is even more significant. Our PV-10 estimates of proved reserves and our standardized measure are equivalent as of December 31, 2013 because, prior to the completion of our initial public offering, we were not subject to entity level taxation. Accordingly, no provision for federal income taxes has been provided because taxable income for 2013 was passed through to our equity holders. However, had we not been a tax exempt entity as of December 31, 2013, our estimated discounted future income tax in respect of our proved, probable and possible reserves would have been approximately $401 million, $368 million and $835 million, respectively. Since the closing of our initial public offering, we are treated as a taxable entity for federal income tax purposes and our future income taxes will be dependent upon our future taxable income. Neither PV-10 nor standardized measure represents an estimate of fair market value of our natural gas and oil properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of estimated reserves held by companies without regard to the specific tax characteristics of such entities.

(2) Substantially all of our estimated probable and possible reserves are classified as undeveloped.

Drilling Inventory and Capital Budget

We intend to develop our multi-year drilling inventory by utilizing our significant expertise in horizontal drilling and fracture stimulation to grow our production, reserves and cash flow. During 2013, we invested approximately $190 million of capital to drill 31 gross (21.3 net) wells. A substantial portion of our development program is focused on horizontal drilling of liquids rich wells in the Terryville Complex, where we spent approximately $163 million in capital expenditures to drill 15 gross (12.1 net) horizontal wells during 2013.

For 2014, we have budgeted a total of $351 million to drill 39 gross (34 net) operated horizontal wells, which includes $268.7 million of capital expenditures we made during the nine months ended September 30, 2014 (including $225.7 million of capital expenditures we made in the Terryville Complex). We expect to fund our 2014 development primarily from cash flows from operations. The majority of our drilling locations and our 2014 development program are focused on the Terryville Complex, where we plan to invest $304 million on drilling 33 gross (29 net) horizontal wells and 3 gross (2.7 net) vertical wells. In the Terryville Complex, we plan to run six rigs for the remainder of 2014 targeting primarily our four primary zones within the Cotton Valley the Upper Red, Lower Red, Lower Deep Pink and Upper Deep Pink. Total vertical depth of these zones ranges from 8,200 to 11,200 feet.

In our East Texas properties in the Joaquin Field, we plan to spend development capital of $29 million to drill 4 gross (4 net) horizontal wells targeting the Cotton Valley formation at vertical depths of 6,000 to 10,000 feet.

In our Rockies properties, we plan to spend $18 million of development capital, primarily in the Tepee Field in the Piceance Basin in Colorado focused on completing 2 gross (2 net) wells.

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The following table provides information regarding our acreage and drilling locations by area, as of December 31, 2013:

	Net Acreage	WI%	Gross Horizontal Drilling Locations(1)(2)(3) Proved	Probable	Possible	Management	Total Gross	Net	Gross Horizontal Drilling Inventory (years)
Terryville Complex	96,733	74%	91	147	450	743	1,431	994	43
East Texas	42,894	79%	54	39	15		108	92	27
Rockies	66,191	41%		23	20		43	4	
Total	205,818	59%	145	209	485	743	1,582	1,091	42

(1) The above table excludes 192 proved vertical drilling locations in our reserve report in the Terryville Complex and 174 identified vertical locations based on management estimates in the Rockies.
(2) Please see Business Our Operations Drilling Locations for more information regarding the process and criteria through which these drilling locations were identified. The drilling locations on which we actually drill will depend on the availability of capital, regulatory approval, commodity prices, costs, actual drilling results and other factors. Please see Risk Factors Risks Related to Our Business 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. Proved, probable and possible locations are based on our reserve report. Management locations are based on management estimates of additional identified drilling locations.
(3) As of September 30, 2014, we had an aggregate drilling inventory of 1,411 identified gross horizontal inventory locations in the Terryville Complex, taking into account drilling activity during the first nine months of 2014. Please see Our Properties Cotton Valley Terryville Complex Proved Reserves Update.

Our extensive inventory and horizontal drilling program in the Terryville Complex is currently focused on four zones within the Cotton Valley formation the Upper Red, Lower Red, Lower Deep Pink and Upper Deep Pink. The table below sets forth our drilling locations by zone as of December 31, 2013 along with the average results for the wells we have drilled within each zone. Please see Business Our Properties Cotton Valley Terryville Complex Horizontal Redevelopment for more detail on our properties in the Terryville Complex.

Lower Cotton Valley Zone	Gross Horizontal Drilling Locations(1)(4) Proved	Probable	Possible	Management	Total	Average Historical Results(2) Producing Wells Drilled(1)	EUR (Bcfe)(3)	Drilling and Completion Costs ($MM)
Upper Red	47	42	40	313	442	25	12.8	$ 9.4
Lower Red	40	40	36	276	392	12	7.9	9.3
Lower Deep Pink	4	28	47	79	158	3	5.8	6.8
Upper Deep Pink		37	42	75	154	1	3.1	10.1
Other Zones			285		285			
Total Terryville Complex	91	147	450	743	1,431	41	10.7	$ 9.2

(1) Please see Business Our Operations Drilling Locations for more information regarding the process and criteria through which these drilling locations were identified. The drilling locations on which we actually drill will depend on the availability of capital, regulatory approval, commodity prices, costs, actual drilling results and other factors. Please see Risk Factors Risks Related to Our Business 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. Proved, probable and possible locations are based on our reserve report. Management locations are based on management estimates of additional identified drilling locations.
(2) Relates to the 41 horizontal wells drilled by us in the four primary target zones in the Terryville Complex and included in our recent reserve report as proved developed reserves as of September 30, 2014.
(3) EUR represents the Estimated Ultimate Recovery or the sum of total gross remaining proved reserves attributable to each location in our recent reserve report and cumulative sales from such location. EUR is shown at the wellhead on a combined basis for oil/condensates and wet gas.
(4) As of September 30, 2014, we had an aggregate drilling inventory of 1,411 identified gross horizontal inventory locations in the Terryville Complex, taking into account drilling activity during the first nine months of 2014. Please see Our Properties Cotton Valley Terryville Complex Proved Reserves Update.

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Our Terryville horizontal development program in 2014 has an average working interest of 86% and our total horizontal development inventory has an average working interest of 69%.

For the Terryville Complex, our 2014 budget assumes an average drilling and completion cost of $9.5 million for gross horizontal wells ($8.3 million per net well) and is based on an average lateral length of 5,824 feet. As part of our long-term development plan, the lateral length of our planned wells is expected to increase and we expect wells within the Terryville Complex to increase to a 7,500 foot lateral length.

Business Strategies

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

Grow production, reserves and cash flow through the development of our extensive drilling inventory. We believe our extensive inventory of low-risk drilling locations, combined with our operating expertise, will enable us to continue to deliver production, reserve and cash flow growth and create shareholder value. As of December 31, 2013, we had assembled an aggregate drilling inventory of 1,582 gross identified horizontal drilling locations, 90% of which are in the Terryville Complex, representing a drilling inventory of over 43 years based on our expected 2014 drilling program. 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. Since initiating our horizontal drilling program with one rig in 2011, we have invested over $521 million in the Terryville Complex through September 30, 2014. With six rigs running in the Terryville Complex as of September 30, 2014, we are one of the most active drillers in the Cotton Valley formation. We intend to dedicate approximately $304 million of our $351 million drilling and completion budget in 2014 to develop the overpressured liquids-rich Terryville Complex through multi-well pad drilling. 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. We also believe our East Texas region has a significant inventory of low-risk, liquids-rich horizontal drilling locations. Finally, we continue to evaluate our leasehold positions in the Rockies and have preliminarily identified over 170 potential vertical locations.

Maintain a disciplined, growth oriented financial strategy. We intend to fund our growth primarily with internally generated cash flows 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 liquidity to fund our drilling program. Since approximately 76% of our acreage in the Terryville Complex was held by production as of December 31,

2013 and no significant drilling commitments are needed to hold our remaining acreage in the near term, we are able to allocate capital among projects in a manner that optimizes both costs and returns, resulting in a highly efficient drilling program.

***Make opportunistic acquisitions that meet our strategic and financial objectives*.** We will seek to acquire oil and gas properties that we believe complement our existing properties in our core areas of operation. In addition to our focus on the Terryville Complex, we are pursuing 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, amassing a land position as of December 31, 2013 of 96,733 net acres, 51,522 net acres of which we believe to be in the core of the play. 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, 2013, we owned approximately 60,041 gross (51,522 net) acres in what we believe to be the core of the Terryville Complex in Lincoln Parish, which we believe to be one of North America s most prolific liquids-rich natural gas fields, characterized by consistent and predictable geology and multiple stacked pay formations confirmed by extensive vertical well control. Through September 30, 2014, our drilling program in the Terryville Complex has produced some of the top performing gas wells in the United States in the previous two years, with single horizontal well results having achieved EURs averaging 10.7 Bcfe per well. Through September 30, 2014, we have brought 41 wells online within our four primary target zones with average 30-day initial production rates of 16.1 MMcfe/d and average drilling and completion costs of $9.2 million per well. Approximately 76% of our acreage in the Terryville Complex was held by production at December 31, 2013 and there are no significant lease expirations until 2017. Additionally, all of our acreage in this play can be held by running a one-rig program over the next 18 months.

***De-risked acreage position with multi-year inventory of liquids-rich drilling opportunities*.** As of December 31, 2013, we had a drilling inventory consisting of 1,582 gross identified horizontal drilling locations, of which approximately 145 are gross proved undeveloped locations. Based on our expected 2014 drilling program and gross identified drilling locations, we have over 42 years of liquids-rich drilling inventory. The majority of our drilling activity has been and will continue to be focused in the Terryville Complex, where we produce liquids-rich natural gas from the overpressured Cotton Valley formation. We have used subsurface data from our vertical wells coupled with 3-D seismic data to identify and prioritize our inventory based on returns. This liquids-rich gas formation allows for NGL processing that, when coupled with the condensate produced, results in strong well economics. For the nine months ended September 30, 2014, 56% of our MRD Segment revenues were attributable to natural gas, 22% to NGLs and 22% to oil.

***Significant operational control with low cost operations*.** On a proved reserves basis, we operate 99% of our properties and have operational control of all of our drilling inventory in the Terryville Complex. We believe maintaining operational control will enable us to enhance returns by implementing more efficient and cost-effective operating practices, through the selection of economic drilling locations, opportunistic timing of development, continuous improvement of drilling, completion and stimulation techniques and development on multi-well pads. As a result of the contiguous nature of our leasehold in the Terryville Complex, its geologic continuity and cross unit lateral pooling, we are able to drill consistently long laterals, averaging over 5,071 lateral feet, which helps us to reduce costs on a per-lateral foot basis and increase our returns. We expect the average lateral length of the 33 gross wells that we expect to drill in the Terryville Complex in 2014 to be 5,824 feet per well. Operating in mature basins in North Louisiana and East Texas 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 MRD Segment lease operating costs declining 35% from $0.50 per Mcfe for the nine months ended September 30, 2013 to $0.33 per Mcfe for the nine months ended September 30, 2014.

Proven and incentivized executive and technical team. We believe our management and technical teams are one of our principal competitive strengths due to our team s significant industry experience and long history of working together in the identification, execution and integration of acquisitions, cost efficient management of profitable, large scale drilling programs and a focus on rates of return. Additionally, our technical team has substantial expertise in advanced drilling and completion technologies and decades of expertise in operating in the North Louisiana and East Texas regions. The members of our management team collectively have an average of 22 years of experience in the oil and natural gas industry. John A. Weinzierl, our Chief Executive Officer, has 24 years of oil and natural gas industry experience as a petroleum engineer, a strong commercial and technical background and extensive experience acquiring and managing oil and natural gas properties. Our management team has a significant economic interest in us directly and through its equity interests in our controlling stockholder, MRD Holdco. We believe our management team is motivated to deliver high returns, create shareholder value and maintain safe and reliable operations.

Our relationship with MEMP. We own a 0.1% general partner interest in MEMP through our ownership of its general partner as well as 50% of MEMP s incentive distribution rights. MEMP s objective as a master limited partnership is to generate stable cash flows, allowing it to make quarterly distributions to its limited partners and, over time, to increase those quarterly distributions. As a result of its familiarity with our management team and our asset base and our track record of prior drop-down transactions, we believe that MEMP is a natural purchaser of properties from us that meet its acquisition criteria. We believe this mutually beneficial relationship enhances MEMP s ability to generate consistent returns on its oil and natural gas properties, provides us with a growing source of cash flow from our partnership interests in MEMP and allows us to monetize producing non-core properties. Since MEMP s initial public offering, we have consummated drop-down transactions with MEMP totaling approximately $391 million. In addition, we may have the opportunity to work jointly with MEMP to pursue certain acquisitions of oil and natural gas properties that may not otherwise be attractive acquisition candidates for either of us individually. While we believe that MEMP would be a preferred acquirer of our mature, non-core assets, we are under no obligation to offer to sell, and it is under no obligation to offer to buy, any of our properties.

Financial strength and flexibility. During 2013, we generated $159 million of pro forma MRD Segment Adjusted EBITDA and made pro forma total capital expenditures of $203 million. During the nine months ended September 30, 2014, we generated pro forma MRD Segment Adjusted EBITDA of $259 million and made pro forma capital expenditures of $268 million. We intend to continue to fund our organic growth predominantly with internally generated cash flows 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 three-to-five year rolling hedge program. As of September 30, 2014, our total liquidity, consisting of cash on hand and available borrowing capacity under our revolving credit facility, was approximately $650.2 million.

Initial Public Offering and Recent Developments

On June 18, 2014, we completed our initial public offering of 49,220,000 shares of common stock at a price to the public of $19.00 per share. Of the 49,220,000 shares offered, 21,500,000 were offered by us and 27,720,000 were offered by the selling stockholder, MRD Holdco. We did not receive any proceeds from the sale of shares by MRD Holdco. We used the net proceeds of approximately $380.2 million from our sale of shares in our initial public offering (i) to redeem the 10.00%/10.75% Senior PIK toggle notes due 2018 (the PIK notes) issued by MRD LLC in their entirety and to pay the applicable premium in connection with such redemption and accrued and unpaid interest to the date of redemption, (ii) together with borrowings of approximately $614.5

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million under our $2.0 billion revolving credit facility entered into in connection with the closing of our initial public offering, to make a cash payment to certain former management members of WildHorse Resources in connection with their contribution to us of their membership interests and incentive units in WildHorse Resources, (iii) to repay borrowings outstanding under WildHorse Resources revolving credit facility and second lien term loan, which we refer to collectively as WildHorse Resources credit agreements, (iv) to reimburse MRD LLC for interest paid on the PIK notes and (v) to pay costs associated with our revolving credit facility.

On July 10, 2014, we completed a private placement of $600.0 million aggregate principal amount of 5.875% senior unsecured notes (the MRD Senior Notes) at par. The MRD Senior Notes will mature on July 1, 2022. Interest on the MRD Senior Notes accrues from July 10, 2014 and will be payable semiannually on January 1 and July 1 of each year, commencing on January 1, 2015. The net proceeds of approximately $586.0 million, after deducting the initial purchasers discounts and commissions and offering expenses, were used to repay a portion of the borrowings outstanding under our revolving credit facility. The amounts to be repaid under our revolving credit facility were incurred to repay the amounts outstanding under WildHorse Resources credit facilities in connection with the closing of our initial public offering. In conjunction with the closing of the offer and sale of the MRD Senior Notes, the borrowing base under our revolving credit facility was automatically decreased by $56.5 million.

On November 4, 2014, our wholly-owned subsidiary, Terryville Mineral & Royalty Partners LP (TRVL), filed a registration statement on Form S-1 with the SEC in connection with its proposed initial public offering of common units representing limited partner interests. In connection with the closing of the proposed offering, we will contribute to TRVL certain overriding royalty interests in approximately 27,000 gross acres in the Terryville Complex in exchange for limited partner interests in TRVL. The royalty interests will entitle TRVL to receive 7% of gross revenues from production within such acreage on all of our existing horizontal producing wells and future wells completed by us. TRVL intends to distribute the net proceeds from the proposed offering to us. A registration statement relating to these securities has been filed with the SEC but has not yet become effective. These securities may not be sold nor may any offers to buy be accepted prior to the time the registration statement becomes effective, and this prospectus does not constitute an offer to sell or a solicitation of any offers to buy these securities.

Acquisition History

We built out our leasehold positions in North Louisiana, East Texas and the Rocky Mountains primarily through the following acquisition activities:

- In November 2007, we acquired interests in the Joaquin Field, which is the core of our East Texas acreage;
- In December 2007, we acquired interests in the Tepee Field in the Piceance Basin in Colorado;
- In April and May 2010, we acquired interests in the Terryville Complex and other North Louisiana fields, which are the core of our North Louisiana acreage;
- In November 2010, we acquired interests in the Spider and E. Logansport Fields in North Louisiana;
- In May 2012, we acquired interests in the Terryville Complex and Double A Field in North Louisiana and East Texas;

In April 2013, we acquired interests in the West Simsboro and Simsboro Fields of the Terryville Complex in North Louisiana;

In November 2013, we acquired the remaining equity interests in Classic Hydrocarbons Holdings, L.P., Classic Hydrocarbons GP Co., L.L.C. and Black Diamond Minerals, LLC, which hold oil and natural gas properties in East Texas, North Louisiana and the Rocky Mountains; and

In February 2014, we repurchased net profits interests in the Terryville Complex from an affiliate of NGP for $63.4 million after customary adjustments. These net profits interests were originally sold to the NGP affiliate upon the completion of certain acquisitions in 2010 by WildHorse Resources.

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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. Upon completion of this offering, MRD Holdco, one of the selling stockholders in this offering, will own approximately 40% of our common stock (or approximately 38% if the underwriters option to purchase additional shares from the selling stockholders is exercised in full). The Funds also collectively indirectly own 50% of MEMP s incentive distribution rights. We are also a party to certain other agreements with MRD Holdco, the Funds and certain of their affiliates. For a description of these agreements, please read Certain Relationships and Related Party Transactions.

Upon completion of this offering, certain former management members of WildHorse Resources, some of which are selling stockholders in this offering along with MRD Holdco, will own approximately 18% of our common stock (or approximately 18% if the underwriters option to purchase additional shares from the selling stockholders is exercised in full). We are party to a services agreement with WildHorse Resources Management Company, LLC, a subsidiary of WildHorse Resources II, LLC. NGP and certain former management members of WildHorse Resources own WildHorse Resources II, LLC. For a description of this services agreement, please read Certain Relationships and Related Party Transactions.

Founded in 1988, NGP is a family of private equity investment funds, with cumulative committed capital of over $14.5 billion since inception, 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, which together with its affiliates has managed over $17 billion in cumulative committed capital since inception.

Relationship with Memorial Production Partners LP

Through our ownership of its general partner, we control MEMP, a publicly traded limited partnership. In addition to the general partner interest, we also 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 East Texas/North Louisiana, the Rockies, South Texas, the Permian 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, 2013:

- MEMP s total estimated proved reserves were approximately 1,015 Bcfe, of which approximately 60% were natural gas and 61% were classified as proved developed reserves; and
- MEMP produced from 2,866 gross (1,663 net) producing wells across its properties, with an average working interest of 58%.

In accordance with MEMP s limited partnership agreement, incentive distribution rights represent the right to receive an increasing percentage of quarterly distributions of MEMP s available cash from operating surplus after the minimum quarterly distribution and the target distribution levels have been achieved. The minimum quarterly distribution is $0.4750 ($1.90 on an annualized basis) per unit. MEMP GP owns 50% of the 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, and MEMP GP owns 50% of the MEMP incentive distribution rights. The incentive distribution rights are payable as follows:

If for any quarter:

MEMP has distributed available cash from operating surplus to the common and subordinated unitholders in an amount equal to the minimum quarterly distribution; and

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MEMP has distributed available cash from operating surplus on outstanding common units in an amount necessary to eliminate any cumulative arrearages in payment of the minimum quarterly distribution;

then, MEMP will distribute any additional available cash from operating surplus for that quarter among the unitholders and the general partner in the following manner:

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

second, 85.0% to all unitholders, pro rata, and 15.0% 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;

thereafter, 75.0% to all unitholders, pro rata, and 25.0% to the holders of the incentive distribution rights (50% of which are owned by MEMP GP).

Since December 2011, MEMP has increased its quarterly cash distribution from $0.4750 ($1.90 on an annualized basis) per unit to $0.5500 ($2.20 on an annualized basis) per unit, which is its most recently announced distribution.

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

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

Our Operations

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 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. Our historical proved reserve estimates and MEMP s historical proved reserve estimates were prepared by NSAI, our independent petroleum engineers. The technical

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persons responsible for preparing our proved reserve estimates meet the requirements with regard to qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. NSAI does not own an interest in any of our properties, nor is it employed by us on a contingent basis. A copy of NSAI s summary reserve report regarding our proved reserves as of December 31, 2013 is included as Appendix B-1 to this prospectus. A copy of NSAI s audit letter regarding the management report of our probable and possible reserves as of December 31, 2013 is included as Appendix B-2 to this prospectus. A copy of NSAI s summary reserve report regarding our proved reserves as of September 30, 2014 with respect to our Terryville Complex acreage is included in Appendix C to this prospectus. A copy of NSAI s summary reserve report regarding the MEMP proved reserves as of December 31, 2013 (the MEMP Reserve Report) is included as Exhibit 99.3 to the registration statement of which this prospectus forms a part.

Our historical probable and possible reserve estimates were prepared by us and audited by NSAI. 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 reserve engineers to review properties and discuss the assumptions and methods used in the reserve estimation process. We provide historical information to NSAI 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 our technical person primarily responsible for liaison with and oversight of our and MEMP s third-party reserve engineers, NSAI, which prepared the reserve reports for our properties and MEMP s properties. Mr. Williams has been practicing petroleum engineering with us since March 2012. Mr. Williams is a Registered Professional Engineer in the State of Texas with over 17 years experience in the estimation and evaluation of reserves. From April 2005 to March 2012, he held various positions at Southwestern Energy Company, most recently as Reservoir Engineering Manager. From August 1998 to April 2005, he served in various capacities at Ryder Scott Company, which culminated in his serving as Vice President. Mr. Williams is a graduate of the University of Texas at Austin with a Bachelor of Science Degree in Petroleum Engineering and with a Master of Science Degree in Petroleum Engineering.

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 estimates of proved reserves presented in the NSAI reports were overseen by Mr. Justin S. Hamilton; Mr. David E. Nice; Mr. Richard B. Talley, Jr.; Mr. Philip S. (Scott) Frost; Mr. Joseph J. Spellman; Mr. Eric J. Stevens; Mr. Craig H. Adams; Mr. Nathan C. Shahan; Mr. J. Carter Henson, Jr., Mr. Allen E. Evans, Jr. and Mr. William J. Knights.

Justin Hamilton has been practicing consulting petroleum engineering at NSAI since 2004. Mr. Hamilton is a Licensed Professional Engineer in the State of Texas (License No. 104999) and has over 13 years of practical experience in petroleum engineering, with over 13 years of experience in the estimation and evaluation of reserves. He graduated from Brigham Young University in 2000 with a B.S. in mechanical engineering and from the University of Texas in 2007 with an M.B.A.

David Nice has been practicing consulting petroleum geology at NSAI since 1998. Mr. Nice is a Licensed Professional Geoscientist in the State of Texas (License No. 346) and has over 28 years of practical experience in petroleum geosciences, with over 15 years of experience in the estimation and evaluation of reserves. He graduated from University of Wyoming in 1982 with a B.S. in geology and in 1985 with an M.S. in geology.

Richard Talley has been practicing consulting petroleum engineering at NSAI since 2004. Mr. Talley is a Licensed Professional Engineer in the State of Texas (License No. 102425) and in the State of Louisiana

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(License No. 36998) and has over 15 years of practical experience in petroleum engineering, with over 9 years of experience in the estimation and evaluation of reserves. He graduated from University of Oklahoma in 1998 with a B.S. in mechanical engineering and from Tulane University in 2001 with an M.B.A.

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

Joseph Spellman has been practicing consulting petroleum engineering at NSAI since 1989. Mr. Spellman is a Licensed Professional Engineer in the State of Texas (License No. 73709) 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 University of Wisconsin-Platteville in 1980 with a B.S. in civil engineering.

Eric Stevens has been practicing consulting petroleum engineering at NSAI since 2007. Mr. Stevens is a Licensed Professional Engineer in the State of Texas (License No. 102415) and has over 11 years of practical experience in petroleum engineering, with over 11 years of experience in the estimation and evaluation of reserves. He graduated from Brigham Young University in 2002 with a B.S. in mechanical engineering.

Craig Adams has been practicing consulting petroleum engineering at NSAI since 1997. Mr. Adams is a Licensed Professional Engineer in the State of Texas (License No. 68137) and has over 29 years of practical experience in petroleum engineering, with over 17 years of experience in the estimation and evaluation of reserves. He graduated from Texas Tech University in 1985 with a B.S. in petroleum engineering.

Nathan Shahan has been practicing consulting petroleum engineering at NSAI since 2007. Mr. Shahan is a Licensed Professional Engineer in the State of Texas (License No. 102389) and has over 12 years of practical experience in petroleum engineering, with over 7 years of experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 2002 with a B.S. in petroleum engineering and in 2007 with a M.E. in petroleum engineering.

Allen Evans has been practicing consulting petroleum geology at NSAI since 1996. Mr. Evans is a Licensed Professional Geoscientist in the State of Texas (License No. 1286) 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 Old Dominion University in 1981 with a B.S. in geology and in 1987 with a M.S. in geology.

Carter Henson has been practicing consulting petroleum engineering at NSAI since 1989. Mr. Henson is a Licensed Professional Engineer in the State of Texas (License No. 73964) and has over 30 years of practical experience in petroleum engineering, with over 25 years of experience in the estimation and evaluation of reserves. He graduated from Rice University in 1981 with a B.S. in mechanical engineering.

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

All eleven technical principals meet or exceed the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; all eleven are 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, 2013 and September 30, 2014 were estimated using a deterministic method. The estimation of reserves involves two distinct determinations. The first determination results in the estimation of the quantities of recoverable oil and natural gas and the second determination results in the estimation of the uncertainty associated with those estimated quantities in accordance with the definitions established under SEC rules. The process of estimating the quantities of recoverable oil and natural gas reserves relies on the use of certain generally accepted analytical procedures. These analytical procedures fall into four broad categories or methods: (1) production performance-based methods; (2) material balance-based methods; (3) volumetric-based methods; and (4) analogy. These methods may be used singularly or in combination by the reserve evaluator in the process of estimating the quantities of reserves. Reserves for proved developed producing wells were estimated using production performance methods for the vast majority of properties. Certain new producing properties with very little production history were forecast using a combination of production performance and analogy to similar production, both of which are considered to provide a relatively high degree of accuracy. Non-producing reserve estimates, for developed and undeveloped properties, were forecast using either volumetric or analogy methods, or a combination of both. These methods provide a relatively high degree of accuracy for predicting proved developed non-producing and proved undeveloped reserves for our properties, due to the mature nature of the properties targeted for development and an abundance of subsurface control data.

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

Under SEC rules, reasonable certainty can be established using techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that has been field tested and has been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. To establish reasonable certainty with respect to our estimated proved reserves, the technologies and economic data used in the estimation of our proved reserves have been demonstrated to yield results with consistency and repeatability, and include production and well test data, downhole completion information, geologic data, electrical logs, radioactivity logs, core analyses, available seismic data and historical well cost and operating expense data.

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

When deterministic methods are used, it is as likely as not that actual remaining quantities recovered will exceed the sum of estimated proved plus probable reserves. When probabilistic methods are used, there should be at least a 50% probability that the actual quantities recovered will equal or exceed the proved plus probable reserves estimates. Probable reserves may be assigned to areas of a reservoir adjacent to proved reserves where data control or interpretations of available data are less certain, even if the interpreted reservoir continuity of

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structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir. Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

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

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

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

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Estimated Reserves

The table below identifies our reserves as of December 31, 2013 per our reserve report for our three areas:

	Oil (MBbl)	Natural Gas (MMcf)	NGLs (MBbl)	Total (MMcfe)
Proved Developed				
Terryville Complex	2,933	220,588	12,050	310,484
East Texas	165	40,435	1,678	51,492
Rockies	306	2,774	176	5,665
Total Proved Developed	**3,403**	**263,797**	**13,905**	**367,641**
Proved Undeveloped				
Terryville Complex	7,585	448,123	23,402	634,049
East Texas	323	90,334	5,270	123,887
Rockies				
Total Proved Undeveloped	**7,908**	**538,457**	**28,672**	**757,936**
Total Proved				
Terryville Complex	10,518	668,711	35,452	944,533
East Texas	487	130,769	6,948	175,379
Rockies	306	2,774	176	5,665
Total Proved Reserves	**11,311**	**802,254**	**42,577**	**1,125,577**
Probable(1)				
Terryville Complex	10,041	453,902	29,056	688,486
East Texas	285	79,765	4,653	109,392
Rockies	153	1,519		2,439
Total Probable Reserves	**10,480**	**535,185**	**33,709**	**800,317**
Possible(1)				
Terryville Complex	36,098	1,031,112	65,869	1,642,911
East Texas	172	48,299	2,817	66,239
Rockies	106	1,128		1,762
Total Possible Reserves	**36,376**	**1,080,539**	**68,686**	**1,710,913**

(1) Substantially all of our estimated probable and possible reserves are classified as undeveloped.

Proved Undeveloped Reserves

As of December 31, 2013, we had 758 Bcfe of proved undeveloped reserves, comprised of 8 MMBbls of oil, 538 Bcf of natural gas and 29 MMBbls of NGLs. None of our PUDs as of December 31, 2013 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 2013 were due to:

- Reclassifications of 20.2 Bcfe into proved developed reserves for implementation of drilling projects; and

- Reduction of 5.2 Bcfe after giving effect to 66.9 Bcfe of additions from the Terryville Complex due to proving up additional drilling locations.

During the year ended December 31, 2013, we spent $69.0 million to convert PUDs to proved developed reserves. As of December 31, 2013 per our reserve report, future development costs relating to the development of PUDs for the years 2014, 2015, 2016, 2017 and 2018 are estimated at approximately $248 million, $358 million, $282 million, $264 million and $160 million, respectively, to capture the balance of drilling the PUD reserves within a five-year timeframe. Approximately 84%, or $1.1 billion, of the future development costs over the next five years are related to development of PUD reserves in the Terryville Complex. As we continue to develop our properties and have more well production and completion data, we believe we will continue to realize cost savings and experience lower relative drilling and completion costs as we convert PUDs into proved developed reserves in the upcoming years. All of our PUD locations are scheduled to be drilled prior to the end of December 31, 2018. Based on our current expectations of its 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.

Production, Revenues and Price History

The following table sets forth information regarding our production, revenues and realized prices and production costs for the nine months ended September 30, 2014 and for the years ended December 31, 2013 and 2012.

	Nine months ended September 30, 2014			
	Terryville	**East Texas**	**Rockies**	**Total**
Production Volumes:				
Oil (MBbls)	560	35	93	688
NGLs (MBbls)	1,300	280	31	1,611
Natural gas (MMcf)	36,583	5,604	888	43,075
Total (MMcfe)	47,750	7,495	1,625	56,870
Average net production (MMcfe/d)	174.9	27.5	6.0	208.3
Average sales price:				
Oil (per Bbl)	$ 97.82	$ 93.09	$ 88.86	$ 96.37
NGL (per Bbl)	45.17	27.62	32.52	41.87
Natural gas (per Mcf)	3.84	4.17	3.60	3.87
Total (Mcfe)	$ 5.32	$ 4.59	$ 7.67	$ 5.30
Average unit costs per Mcfe:				
Lease operating expense	$ 0.24	$ 0.83	$ 0.74	$ 0.33

	Year Ended December 31, 2013			
	Terryville	**East Texas**	**Rockies**	**Total**
Production Volumes:				
Oil (MBbls)	475	165	25	665
NGLs (MBbls)	1,243	177	37	1,457
Natural gas (MMcf)	27,398	6,249	445	34,092
Total (Mmcfe)	37,705	8,297		