Matador Resources Co
Form 10-K
February 29, 2016
Table of Contents

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

(Mark One)

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

For the fiscal year ended December 31, 2015

or

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

For the transition period from to

Commission file number 001-34574

Matador Resources Company
(Exact name of registrant as specified in its charter)

Texas (State or other jurisdiction of incorporation or organization)	27-4662601 (I.R.S. Employer Identification No.)
5400 LBJ Freeway, Suite 1500 Dallas, Texas 75240 (Address of principal executive offices)	75240 (Zip Code)

Registrant's telephone number, including area code: (972) 371-5200

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

Title of each class	Name of each exchange on which registered
Common Stock, par value $0.01 per share	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ý No ¨

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No ¨

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

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant’s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ý

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of “large accelerated filer,” “accelerated filer” and “smaller reporting company” in Rule 12b-2 of the Exchange Act.

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

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

The aggregate market value of the voting and non-voting common equity of the registrant held by non-affiliates, computed by reference to the price at which the common equity was last sold, as of the last business day of the registrant’s most recently completed second fiscal quarter was $1,861,025,900.

As of February 25, 2016, there were 85,801,633 shares of common stock outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

The information required by Part III of this Annual Report on Form 10-K, to the extent not set forth herein, is incorporated by reference to the registrant’s definitive proxy statement relating to the 2016 Annual Meeting of Shareholders which will be filed with the Securities and Exchange Commission within 120 days after the end of the fiscal year to which this Annual Report on Form 10-K relates.

MATADOR RESOURCES COMPANY
FORM 10-K
FOR THE FISCAL YEAR ENDED DECEMBER 31, 2015
TABLE OF CONTENTS

		Page
PART I		
ITEM 1.	BUSINESS	2
ITEM 1A.	RISK FACTORS	30
ITEM 1B.	UNRESOLVED STAFF COMMENTS	49
ITEM 2.	PROPERTIES	49
ITEM 3.	LEGAL PROCEEDINGS	49
ITEM 4.	MINE SAFETY DISCLOSURES	49
PART II		
ITEM 5.	MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES	50
ITEM 6.	SELECTED FINANCIAL DATA	53
ITEM 7.	MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS	55
ITEM 7A.	QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK	74
ITEM 8.	FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA	75
ITEM 9.	CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE	75
ITEM 9A.	CONTROLS AND PROCEDURES	75
ITEM 9B.	OTHER INFORMATION	78
PART III		
ITEM 10.	DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE	78
ITEM 11.	EXECUTIVE COMPENSATION	78
ITEM 12.	SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS	78
ITEM 13.	CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE	78
ITEM 14.	PRINCIPAL ACCOUNTING FEES AND SERVICES	78
PART IV		
ITEM 15.	EXHIBITS AND FINANCIAL STATEMENT SCHEDULES	79

Table of Contents

CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

Certain statements in this Annual Report on Form 10-K constitute “forward-looking statements” within the meaning of Section 27A of the Securities Act of 1933, as amended, or the Securities Act, and Section 21E of the Securities Exchange Act of 1934, as amended, or the Exchange Act. Additionally, forward-looking statements may be made orally or in press releases, conferences, reports, on our website or otherwise, in the future, by us or on our behalf. Such statements are generally identifiable by the terminology used such as “anticipate,” “believe,” “continue,” “could,” “estimate,” “expect,” “forecasted,” “hypothetical,” “intend,” “may,” “might,” “plan,” “potential,” “predict,” “project,” “should” or other si
By their very nature, forward-looking statements require us to make assumptions that may not materialize or that may not be accurate. Forward-looking statements are subject to known and unknown risks and uncertainties and other factors that may cause actual results, levels of activity and achievements to differ materially from those expressed or implied by such statements. Such factors include, among others: general economic conditions, changes in oil, natural gas and natural gas liquids prices and the demand for oil, natural gas and natural gas liquids, the success of our drilling program, the timing of planned capital expenditures, sufficient cash flow from operations together with available borrowing capacity under our credit agreement, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, the proximity to and capacity of transportation facilities, availability of acquisitions, our ability to integrate acquisitions, including the integration of Harvey E. Yates Company, with our business, weather and environmental conditions, uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, and the other factors discussed below and elsewhere in this Annual Report on Form 10-K and in other documents that we file with or furnish to the United States Securities and Exchange Commission, or the SEC, all of which are difficult to predict.
Forward-looking statements may include statements about:

- our business strategy;
- our reserves;
- our technology;
- our cash flows and liquidity;
- our financial strategy, budget, projections and operating results;
- our oil and natural gas realized prices;
- the timing and amount of future production of oil and natural gas;
- the availability of drilling and production equipment;
- the availability of oil field labor;
- the amount, nature and timing of capital expenditures, including future exploration and development costs;
- the availability and terms of capital;
- our drilling of wells;
- our ability to negotiate and consummate acquisition and divestiture opportunities;
- government regulation and taxation of the oil and natural gas industry;
- our marketing of oil and natural gas;
- our exploitation projects or property acquisitions;
- the integration of acquisitions, including the integration of Harvey E. Yates Company, with our business;
- our ability to construct and operate midstream facilities;
- our costs of exploiting and developing our properties and conducting other operations;
- general economic conditions;
- competition in the oil and natural gas industry;
- the effectiveness of our risk management and hedging activities;
- environmental liabilities;
- counterparty credit risk;
- developments in oil-producing and natural gas-producing countries;
- our future operating results;

- estimated future reserves and the present value thereof; and
- our plans, objectives, expectations and intentions contained in this Annual Report on Form 10-K that are not historical.

Although we believe that the expectations conveyed by the forward-looking statements are reasonable based on information available to us on the date such forward-looking statements were made, no assurances can be given as to future results, levels of activity, achievements or financial condition.

You should not place undue reliance on any forward-looking statement and should recognize that the statements are predictions of future results, which may not occur as anticipated. Actual results could differ materially from those anticipated in the forward-looking statements and from historical results, due to the risks and uncertainties described above, as well as others not now anticipated. The impact of any one factor on a particular forward-looking statement is not determinable with certainty

Table of Contents

as such factors are interdependent upon other factors. The foregoing statements are not exclusive and further information concerning us, including factors that potentially could materially affect our financial results, may emerge from time to time. We do not intend to update forward-looking statements to reflect actual results or changes in factors or assumptions affecting such forward-looking statements, except as required by law, including the securities laws of the United States and the rules and regulations of the SEC.

PART I

Item 1. Business.

In this Annual Report on Form 10-K, references to "we," "our" or the "Company" refer to Matador Resources Company and its subsidiaries as a whole (unless the context indicates otherwise) and references to "Matador" refer solely to Matador Resources Company. For certain oil and natural gas terms used in this Annual Report on Form 10-K, see the "Glossary of Oil and Natural Gas Terms" included in this Annual Report on Form 10-K.

General

We are an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with an emphasis on oil and natural gas shale and other unconventional plays. Our current operations are focused primarily on the oil and liquids-rich portion of the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. We also operate in the Eagle Ford shale play in South Texas and the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas.

We are a Texas corporation founded in July 2003 by Joseph Wm. Foran, Chairman and CEO. Mr. Foran began his career as an oil and natural gas independent in 1983 when he founded Foran Oil Company with $270,000 in contributed capital from 17 friends and family members. Foran Oil Company was later contributed to Matador Petroleum Corporation upon its formation by Mr. Foran in 1988. Mr. Foran served as Chairman and Chief Executive Officer of that company from its inception until it was sold in June 2003 to Tom Brown, Inc., in an all cash transaction for an enterprise value of approximately $388.5 million.

On February 2, 2012, our common stock began trading on the New York Stock Exchange (the "NYSE") under the symbol "MTDR." Prior to trading on the NYSE, there was no established public trading market for our common stock.

Our goal is to increase shareholder value by building oil and natural gas reserves, production and cash flows at an attractive rate of return on invested capital. We plan to achieve our goal by, among other items, executing the following business strategies:

- focus our exploration and development activities primarily on unconventional plays, including the Wolfcamp and Bone Spring plays in the Delaware Basin, the Eagle Ford shale in South Texas and the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas;
- identify, evaluate and develop additional oil and natural gas plays as necessary to maintain a balanced portfolio of oil and natural gas properties;
- continue to improve operational and cost efficiencies;
- identify and develop midstream opportunities that support and enhance our exploration and development activities;
- maintain our financial discipline; and
- pursue opportunistic acquisitions and divestitures.

Despite a challenging commodity price environment in 2015, the successful execution of our business strategies led to significant increases in our oil and natural gas production and proved oil and natural gas reserves in 2015. We also significantly increased our leasehold position in the Delaware Basin. In addition, we concluded several important transactions in 2015, including our merger with Harvey E. Yates Company ("HEYCO"), a subsidiary of HEYCO Energy Group, Inc., which added substantially to our Delaware Basin acreage position, our first issuance of senior unsecured notes, an equity offering and the sale of a portion of our midstream assets in Loving County, Texas to an affiliate of EnLink Midstream Partners, LP ("EnLink"). These transactions increased our operational flexibility and further strengthened our balance sheet.

2015 Highlights

Increased Oil, Natural Gas and Oil Equivalent Production

For the year ended December 31, 2015, we achieved record oil, natural gas and average daily oil equivalent production. In 2015, we produced 4.5 million Bbl of oil, an increase of 35%, as compared to 3.3 million Bbl of oil produced in 2014. We also produced 27.7 Bcf of natural gas, an increase of 81% from 15.3 billion Bcf of natural gas produced in 2014. Our average daily oil equivalent production for the year ended December 31, 2015 was 24,955 BOE per day, including 12,306 Bbl of oil per day and 75.9 MMcf of natural gas per day, an increase of 55%, as compared to 16,082 BOE per day, including 9,095 Bbl of oil per day and 41.9 MMcf of natural gas per day, for the year ended December 31, 2014. The increase in oil production was primarily attributable to our ongoing delineation and development operations in the Delaware Basin throughout 2015, as well as our development activities in the Eagle Ford shale during early 2015. The increase in natural gas production was primarily attributable to new, non-operated Haynesville shale wells completed and placed on production in our Elm Grove properties in Northwest Louisiana in the latter half of 2014 and throughout 2015, but also includes increased natural gas production associated with our operations in both the Delaware Basin and the Eagle Ford shale. Oil production comprised 49% of our total production (using a conversion ratio of one Bbl of oil per six Mcf of natural gas) for the year ended December 31, 2015, as compared to 57% for the year ended December 31, 2014.

Increased Oil and Oil Equivalent Reserves

At December 31, 2015, our estimated total proved oil and natural gas reserves were 85.1 million BOE, including 45.6 million Bbl of oil and 236.9 Bcf of natural gas, which is an increase of 24% from December 31, 2014. The associated PV-10 of our estimated total proved oil and natural gas reserves decreased 48% to $541.6 million at December 31, 2015 from $1.04 billion at December 31, 2014, as a result of declining oil and natural gas prices throughout 2015. PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10 to Standardized Measure, see "—Estimated Proved Reserves."

Our proved oil reserves grew 89% to 45.6 million Bbl at December 31, 2015 from 24.2 million Bbl at December 31, 2014. This growth in oil reserves was primarily attributable to our drilling program in the Delaware Basin during 2015. Our proved natural gas reserves decreased 11% to 236.9 Bcf at December 31, 2015 from 267.1 Bcf at December 31, 2014. This decrease in proved natural gas reserves was largely attributable to a decrease in our proved undeveloped natural gas reserves, principally from the reclassification of proved undeveloped natural gas reserves to contingent resources, primarily in the Haynesville shale, as a result of the decline in natural gas prices during 2015 as noted below in "— Estimated Proved Reserves." As long as the leasehold acreage associated with these previously classified proved undeveloped natural gas reserves is held by production from existing Haynesville wells, however, these natural gas volumes remain available to be developed by Matador or the operator at a future time should natural gas prices improve, drilling and completion costs decline or new technologies be developed that increase expected recoveries.

At December 31, 2015, proved developed reserves included 17.1 million Bbl of oil and 101.4 Bcf of natural gas, and proved undeveloped reserves included 28.5 million Bbl of oil and 135.5 Bcf of natural gas. Proved developed reserves comprised 40% and proved oil reserves comprised 54% of our total proved oil and natural gas reserves, respectively, at December 31, 2015. Proved developed reserves comprised 45% of our total reserves and proved oil reserves comprised 35% of our total proved oil and natural gas reserves, respectively, at December 31, 2014.

Operational Highlights

We focus on optimizing the development of our resource base by seeking ways to maximize our recovery per well relative to the cost incurred and to minimize our operating costs per BOE produced. We apply an analytical approach to track and monitor the effectiveness of our drilling and completion techniques and service providers. This allows us to more effectively manage operating costs, the pace of development activities, technical applications, the gathering and marketing of our production and capital allocation. Additionally, we concentrate on our core areas, which allows us to achieve economies of scale and reduce operating costs. Largely as a result of these factors, we believe that we have increased our technical knowledge of drilling, completing and producing Delaware Basin wells, particularly over the past two years, as we continued to apply there what we learned from our Eagle Ford shale, as well as from our Haynesville shale, experience. The Delaware Basin will continue to be our primary area of focus in 2016.

We completed and began producing oil and natural gas from 41 gross (25.0 net) wells in the Delaware Basin in 2015, including 27 gross (23.7 net) operated and 14 gross (1.3 net) non-operated wells. We also substantially increased our acreage position in the Delaware Basin during 2015. As a result, at December 31, 2015 our total acreage position in the Delaware Basin had increased to approximately 157,100 gross (88,800 net) acres, primarily in Loving County, Texas and Lea and Eddy Counties, New Mexico. Overall, we have been very pleased with the initial performance of the wells we have drilled and completed, or participated in as a non-operator, thus far in our six main prospect areas in the Delaware Basin—the Wolf and Jackson Trust prospect areas in Loving County, Texas, the Rustler Breaks and Arrowhead prospect areas in Eddy County, New Mexico and the Ranger and Twin Lakes prospect areas in Lea County, New Mexico. As a result, our Delaware Basin properties have become an increasingly important component of our asset portfolio. Our average daily oil equivalent production from the Delaware Basin grew 3.6-fold from 1,790 BOE per day, including 1,314 Bbl of oil per day and 2.9 MMcf of natural gas per day, in 2014 to an average daily oil equivalent production of 6,518 BOE per day, including 4,648 Bbl of oil per day and 11.2 MMcf of natural gas per day, in 2015. We expect our Delaware Basin production to increase throughout 2016 as we continue the delineation and development of these properties.

During 2015, we made significant progress in reducing drilling costs and times for both Wolfcamp and Bone Spring horizontal wells in the Delaware Basin. Our focus on improving drilling times and operational efficiencies has cut drilling

Table of Contents

times by as much as 50% or more on recent Wolfcamp wells in the Wolf and Rustler Breaks prospect areas as compared to earlier wells drilled in those prospect areas. In the Wolf prospect area in Loving County, Texas, for example, Wolfcamp drilling times (spud to total depth) have been reduced from an average of 43 days in 2014 to as low as 18 days on a well drilled in late 2015. In the Rustler Breaks prospect area in Eddy County, New Mexico, where the Wolfcamp formation is shallower, Wolfcamp drilling times have been reduced from an average of 32 days in 2014 and early 2015 to as low as 15 days on recent wells drilled in late 2015. In addition, our most recent Second Bone Spring horizontal well in our Rustler Breaks prospect area was drilled from spud to total depth in 12 days, making it the fastest Second Bone Spring horizontal well we have drilled to date. These increased drilling efficiencies are the result of a number of factors such as Company-supported modifications to our contracted drilling rigs, including 7,500-psi circulating systems, integrated equipment upgrades and other efficiency-related modifications, as well as more experienced personnel on each rig, improved bit designs and starting to drill wells in “batch” mode in some areas, particularly in the Wolf prospect area where we are in development mode.

These increased drilling and completion efficiencies, coupled with service cost reductions of varying amounts, reduced overall well costs in 2015. Recent Wolfcamp wells in the Wolf prospect area have been drilled and completed for approximately $6.5 million, including production facilities and other related infrastructure. In the Rustler Breaks prospect area, we expect to drill and complete Wolfcamp wells for an average of $6.0 to $6.5 million in the first quarter of 2016, including production facilities and other related infrastructure. Our most recent Second Bone Spring well in this area was drilled and completed for approximately $4.0 million on an existing multi-well pad, which is the least expensive Second Bone Spring well we have drilled thus far on our Delaware Basin acreage. These well costs are substantially reduced from those of initial wells drilled in these areas. We plan to continue to focus on improving operational efficiencies as we move closer to full development of our Delaware Basin assets.

We completed and began producing oil and natural gas from 18 gross (17.3 net) wells in the Eagle Ford shale in 2015, all in the early portion of the year, including 17 gross (17.0 net) operated wells and one gross (0.3 net) non-operated well. During the second quarter of 2015, we concluded our drilling and completion operations in the Eagle Ford for 2015 and did not drill or complete any additional operated wells in the Eagle Ford shale for the remainder of 2015.

We did not drill any operated Haynesville shale wells during 2015, but we did participate in 22 gross (1.9 net) non-operated wells drilled in the Haynesville shale in Northwest Louisiana. The most impactful of these were the Haynesville wells drilled and completed by a subsidiary of Chesapeake Energy Corporation (“Chesapeake”) on our Elm Grove properties in southern Caddo Parish. In 2015, Chesapeake completed and placed on production nine gross (1.6 net) wells at Elm Grove. As a result of these 2015 completions and additional non-operated Haynesville wells completed and placed on production in the latter half of 2014, our Haynesville natural gas production grew 135% from 19.7 MMcf of natural gas per day in 2014 to 46.4 MMcf of natural gas per day in 2015.

Financing Arrangements

On April 14, 2015, we issued $400.0 million of 6.875% senior unsecured notes due 2023 in a private placement and, on October 21, 2015, we exchanged all of the privately placed senior notes for a like principal amount of 6.875% senior notes due 2023 that have been registered under the Securities Act. On April 21, 2015, we completed a public offering of 7,000,000 shares of our common stock. After deducting offering costs totaling approximately $1.2 million, we received net proceeds of approximately $187.6 million. Finally, during the fourth quarter of 2015, the lenders party to our third amended and restated credit agreement (the “Credit Agreement”), under which we had no borrowings outstanding at December 31, 2015, reaffirmed our borrowing base at $375.0 million and extended the maturity date of the credit facility to October 16, 2020. See Note 6 to the consolidated financial statements in this Annual Report on Form 10-K for more details on each of the above items.

Acquisitions and Divestitures

On February 27, 2015, we completed a business combination pursuant to which one of our wholly-owned subsidiaries merged with HEYCO (the “HEYCO Merger”), combining certain oil and natural gas producing properties and undeveloped acreage located in Lea and Eddy Counties, New Mexico with our Delaware Basin operations. In the HEYCO Merger, we obtained approximately 58,600 gross (18,200 net) acres strategically located between our existing acreage in our Ranger and Rustler Breaks prospect areas. See Note 5 to the consolidated financial statements in this Annual Report on Form 10-K for more details on the HEYCO Merger.

We also acquired approximately 1,900 net acres contributed into two joint ventures with certain affiliates of HEYCO Energy Group, Inc. We have agreed to contribute an aggregate of approximately $14 million in exchange for a 50% interest in both entities. See Note 16 to the consolidated financial statements in this Annual Report on Form 10-K for more details on the joint ventures.

On October 1, 2015, we completed the sale of our wholly-owned subsidiary that owned certain natural gas gathering and processing assets in the Delaware Basin in Loving County, Texas (the “Loving County System”) to EnLink. The Loving County System included a cryogenic natural gas processing plant with approximately 35 MMcf per day of inlet capacity (the

Table of Contents

“Processing Plant”) and approximately six miles of high-pressure gathering pipeline which connects our gathering system to the Processing Plant. Pursuant to the terms of the transaction, EnLink paid cash consideration of approximately $143.4 million, excluding customary purchase price adjustments, and we dedicated our leasehold interests in Loving County as of the closing date pursuant to a 15-year fixed-fee natural gas gathering and processing agreement and provided a volume commitment in exchange for priority one service. See Note 5 and Note 13 to the consolidated financial statements in this Annual Report on Form 10-K for more details regarding the transaction with EnLink.

Principal Areas of Interest

Our focus since inception has been the exploration for oil and natural gas in unconventional plays with an emphasis in recent years on the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas, the Eagle Ford shale play in South Texas and the Haynesville shale play in Northwest Louisiana. During 2015, we devoted most of our efforts and most of our capital investment to our drilling and completion operations in the Wolfcamp and Bone Spring plays in the Delaware Basin and the Eagle Ford shale in South Texas, although we completed our planned operated drilling and completion activities in the Eagle Ford shale for 2015 in the second quarter. Since our inception, our exploration efforts have concentrated primarily on known hydrocarbon-producing basins with well-established production histories offering the potential for multiple-zone completions. We have also sought to balance the risk profile of our prospects by exploring for more conventional targets as well, although at December 31, 2015, essentially all of our efforts were focused on unconventional plays.

At December 31, 2015, our principal areas of interest consisted of the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas, the Eagle Ford shale play in South Texas, and the Haynesville shale play, as well as the traditional Cotton Valley and Hosston (Travis Peak) formations, in Northwest Louisiana and East Texas.

The following table presents certain summary data for each of our operating areas as of and for the year ended December 31, 2015.

			Producing Wells		Total Identified Drilling Locations (1)		Estimated Net Proved Reserves (2)		Avg. Daily Production (BOE/d) (3)
	Gross Acreage	Net Acreage	Gross	Net	Gross	Net	MBOE (3)	% Developed	
Southeast New Mexico/West Texas:									
Delaware Basin (4)	157,133	88,750	256	96.0	3,543	1,416.9	47,124	27.3	6,518
South Texas:									
Eagle Ford (5)	39,035	29,255	134	115.5	260	227.5	19,015	62.5	10,263
Northwest Louisiana/East Texas:									
Haynesville	20,707	13,007	198	18.4	448	109.2	18,148	46.3	7,731
Cotton Valley (6)	21,775	19,185	93	58.4	71	50.1	840	100.0	443
Area Total (7)	26,663	23,831	291	76.8	519	159.3	18,988	48.7	8,174
Other:									
Wyoming, Utah, Idaho	75,674	35,732	—	—	—	—	—	—	—
Total	298,505	177,568	681	288.3	4,322	1,803.7	85,127	40.0	24,955

(1) Identified and engineered drilling locations. These locations have been identified for potential future drilling and were not producing at December 31, 2015. The total net engineered drilling locations are calculated by multiplying the gross engineered drilling locations in an operating area by our working interest participation in such locations. At December 31, 2015, these engineered drilling locations included only 118 gross (71.1 net) locations to which

(2) we have assigned proved undeveloped reserves in the Wolfcamp or Bone Spring plays in the Delaware Basin, 27 gross (26.8 net) locations to which we have assigned proved undeveloped reserves in the Eagle Ford and 26 gross (9.4 net) locations to which we have assigned proved undeveloped reserves in the Haynesville. We had no proved undeveloped reserves assigned to engineered drilling locations in any other formations at December 31, 2015. These estimates were prepared by our engineering staff and audited by Netherland, Sewell & Associates, Inc., independent reservoir engineers. For additional information regarding our oil and natural gas reserves, see "—Estimated Proved Reserves" and Supplementary Oil and Natural Gas Disclosures included in the unaudited supplementary information in this Annual Report on Form 10-K, which is incorporated herein by reference.

(3) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(4) Includes potential future engineered drilling locations in the Wolfcamp, Bone Spring, Delaware and Avalon plays on our acreage in the Delaware Basin at December 31, 2015.

(5) Includes one well producing small quantities of oil from the Austin Chalk formation and two wells producing small quantities of natural gas from the San Miguel formation in Zavala County, Texas.

(6) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas.

(7) Some of the same leases cover the net acres shown for both the Haynesville formation and the shallower Cotton Valley formation. Therefore, the sum of the net acreage for both formations is not equal to the total net acreage for Northwest Louisiana and East Texas. This total includes acreage that we are producing from or that we believe to be prospective for these formations.

We are active both as an operator and as a co-working interest owner with larger industry participants, including affiliates of EOG Resources, Inc., Royal Dutch Shell plc, Chesapeake Energy Corporation, EP Energy Company, Concho Resources Inc., Devon Energy Corporation, Cimarex Energy Company, BHP Billiton, Mewbourne Oil Company, Occidental Petroleum Corporation, Chevron Corporation and others. At December 31, 2015, we operated the majority of our acreage in the Delaware Basin in Southeast New Mexico and West Texas. In those wells where we are not the operator, our working interests are often relatively small. At December 31, 2015, we also were the operator for approximately 95% of our Eagle Ford acreage and approximately two-thirds of our Haynesville acreage, including approximately 36% of our acreage in what we believe is the core area of the Haynesville play. A large portion of our acreage in the core area of the Haynesville shale is operated by Chesapeake.

While we do not always have direct access to our operating partners' drilling plans with respect to future well locations on non-operated properties, we do attempt to maintain ongoing communications with the technical staff of these operators in an effort to understand their drilling plans for purposes of our capital expenditure budget and our booking of any related proved undeveloped well locations and reserves. We review these locations with Netherland, Sewell & Associates, Inc., independent reservoir engineers, on a periodic basis to ensure their concurrence with our estimates of these drilling plans and our approach to booking these reserves.

Southeast New Mexico and West Texas — Delaware Basin

The greater Permian Basin in Southeast New Mexico and West Texas is a mature exploration and production province with extensive developments in a wide variety of petroleum systems resulting in stacked target horizons in many areas. Historically, the majority of development in this basin has focused on relatively conventional reservoir targets, but the combination of advanced formation evaluation, 3-D seismic technology, horizontal drilling and hydraulic fracturing technology is enhancing the development potential of this basin, particularly in the organic rich shales, or source rocks, of the Wolfcamp and in the low permeability sand and carbonate reservoirs of the Bone Spring, Avalon and Delaware formations. We believe these formations, which have been typically considered to be low quality rocks because of their low permeability, are strong candidates for horizontal drilling and advanced hydraulic fracturing techniques.

In the western part of the Permian Basin, also known as the Delaware Basin, the Lower Permian age Bone Spring (also called the Leonardian) and Wolfcamp formations are several thousand feet thick and contain stacked layers of shales, sandstones, limestones and dolomites. These intervals represent a complex and dynamic submarine depositional system that also includes organic rich shales that are proven to be the source rocks for oil and natural gas produced in the basin. Historically, production has come from the "conventional" reservoirs; however, we and other industry players have realized that the source rocks also have sufficient porosity and permeability to be commercial reservoirs. In addition, the source rocks are interbedded with reservoir layers that have filled with hydrocarbons, both of which can produce significant volumes of oil and natural gas when connected by horizontal wellbores with multi-stage hydraulic fracture treatments. Particularly in the Delaware Basin, there are multiple horizontal targets in a given area that exist within the several thousand feet of hydrocarbon bearing layers that make up the Bone Spring and Wolfcamp plays. Multiple horizontal drilling and completion targets are being identified and targeted by companies, including us, throughout the vertical section including the Delaware, Avalon, Bone Spring (First, Second and Third Sand) and several intervals within the Wolfcamp shale, often identified as Wolfcamp A through D.

We substantially increased our acreage position in the Delaware Basin during 2015, and as a result, at December 31, 2015, our total acreage position in Southeast New Mexico and West Texas had increased to approximately 157,100 gross (88,800 net) acres, primarily in Loving County, Texas and Lea and Eddy Counties, New Mexico. These acreage totals included approximately 32,100 gross (19,400 net) acres in our Ranger prospect area in Lea County, 47,400 gross (16,900 net) acres in our Arrowhead prospect area in Eddy County, 20,700 gross (13,400 net) acres in our Rustler Breaks prospect area in Eddy County, 12,200 gross (7,500 net) acres in our Wolf and Jackson Trust prospect areas in Loving County and 42,300 gross (29,900 net) acres in our Twin Lakes prospect area in Lea County at December 31, 2015. We consider the vast majority of our Delaware Basin acreage position to be prospective for oil and liquids-rich targets in the Bone Spring and Wolfcamp formations. Other potential targets on certain portions of our acreage include the Avalon and Delaware formations, as well as the Abo, Strawn, Devonian, Penn Shale, Atoka and Morrow formations. At December 31, 2015, our acreage position in the Delaware Basin was approximately 35% held by existing production, including substantially all of the acreage acquired in the HEYCO Merger.

During the year ended December 31, 2015, we continued the delineation and development of our Delaware Basin acreage. We completed and began producing oil and natural gas from 41 gross (25.0 net) wells in the Delaware Basin, including 27 gross (23.7 net) operated wells and 14 gross (1.3 net) non-operated wells, throughout our various prospect areas. At December 31, 2015, we had tested a number of different producing horizons at various locations across our acreage position,

Table of Contents

including the Brushy Canyon, Avalon, two benches of the Second Bone Spring, the Third Bone Spring, three benches of the Wolfcamp A, including the X and Y sands and the more organic, lower section of the Wolfcamp A, two benches of the Wolfcamp B and the Wolfcamp D. Most of our delineation and development efforts have been focused on multiple completion targets between the Second Bone Spring and the Wolfcamp B.

In our Wolf prospect area in Loving County, Texas, we made significant progress in reducing drilling costs and times for Wolfcamp horizontal wells during 2015. Our focus on improving drilling times and operational efficiencies cut drilling times by as much as 58% on Wolfcamp wells drilled in late 2015 in the Wolf prospect area as compared to earlier wells drilled in this area. Wolfcamp drilling times (spud to total depth) were reduced from an average of 43 days in 2014 to as low as 18 days on a well drilled in late 2015. These increased drilling efficiencies are the result of a number of factors such as Company-supported modifications to our contracted drilling rigs, including 7,500-psi circulating systems, integrated equipment upgrades and other efficiency-related modifications, as well as more experienced personnel on each rig, improved bit designs and drilling wells in “batch” mode in the Wolf prospect area where we are in development mode. These increased drilling and completion efficiencies, coupled with service cost reductions of varying amounts, reduced overall well costs in the Wolf prospect area in 2015. Recent Wolfcamp wells in the Wolf prospect area have been drilled and completed for approximately $6.5 million in late 2015, including production facilities and related infrastructure costs. At December 31, 2015, we were conducting multi-well pad operations on two separate leases in our Wolf prospect area with one rig drilling a four-well horizontal stack on the Dick Jay pad and another rig drilling a three-well horizontal stack on our Dorothy White leasehold.

We continue to improve our fracture treatment design in the Delaware Basin. In the Wolf prospect area in late October 2015, we tested the use of a fracture stimulation diverting agent in one of our Billy Burt completions in the northwest portion of the Wolf prospect—the Billy Burt 90-TTT-B33 WF #201H. The Billy Burt 90-TTT-B33 WF #201H well was a Wolfcamp A-Y test and has a completed lateral length of 6,725 feet. The diverting agent was used in an effort to improve the efficiency of each fracturing stage and to ensure as many perforation clusters were treated as possible, while simultaneously improving well costs. Breakdown pressures monitored during the fracture treatments on the Billy Burt 90-TTT-B33 WF #201H well indicated that additional perforations were opened and new hydraulic fractures were created after the diverting agent was pumped in various stages of the fracturing operation. The Billy Burt 90-TTT-B33 WF #201H well initially tested about 1,100 BOE per day (68% oil), consisting of about 750 Bbl of oil per day and 2.1 MMcf of natural gas per day. More importantly, however, early production from the well over its initial 90 days was about 27% higher than the immediate 80-acre offsetting well having a similar lateral length, but where no diverting agent was used. We continue to refine and improve our fracture treatments designs, including the use of both existing technologies and new technologies as they become available and are determined to be beneficial, in an effort to improve the overall recovery from our Delaware Basin wells.

We made significant progress with our midstream operations in 2015, particularly in the Wolf prospect area. As noted above in “—2015 Highlights—Acquisitions and Divestitures,” we completed the sale of the Loving County System to EnLink for cash proceeds of approximately $143.4 million, excluding customary purchase price adjustments, on October 1, 2015. At closing, the Processing Plant had been online for only about a month. Although we sold the Loving County System, we retained our infield natural gas gathering system up to a central delivery point and our other midstream assets in the Wolf prospect area, including oil and water gathering systems. We also retained our interest in a commercial salt water disposal facility in Loving County, operated by a joint venture controlled by the Company. During 2015, the joint venture entity disposed of over 5.5 million barrels of salt water, with a total savings to the Company of approximately $6.5 million in salt water disposal costs. In addition, the joint venture entity began disposing of third-party salt water on a commercial basis in the fourth quarter of 2015.

We also made significant progress delineating and testing our acreage position in the Rustler Breaks prospect area in Eddy County, New Mexico in 2015. At December 31, 2014, we had drilled and completed only one well in Rustler Breaks—the Rustler Breaks 12-24S-27E RB #224H (formerly the Rustler Breaks 12-24-27 #1H)—in a single horizon of the Wolfcamp B. By the end of 2015, we had tested four different producing horizons—the Second Bone Spring, the Wolfcamp A-XY and two benches of the Wolfcamp B—across our Rustler Breaks prospect area from southeast to northwest.

One of the highlights and technical achievements of 2015 was the successful drilling and completion of our first three-zone stacked lateral test on a single drilling pad in the Rustler Breaks prospect area. From this single pad location, we successfully stacked three horizontal wells targeting three different horizons including, from shallowest to deepest, the Second Bone Spring, Wolfcamp A-XY and Wolfcamp B. The Wolfcamp B well (Tiger 14-24S-28E RB #224H) tested 1,533 BOE per day (42% oil), the Wolfcamp A-XY well (Tiger 14-24S-28E RB #204H) tested 1,405 BOE per day (75% oil) and the Second Bone Spring well (Tiger 14-24S-28E RB #124H) tested 702 BOE per day (83% oil). We were encouraged not only by the early results of this important technical advance, but also by the potential further savings that we anticipate can be achieved through the repeatability of this “stacked” pay concept at other locations. We expect to drill and complete Wolfcamp wells in the Rustler Breaks prospect area for an average of $6.0 to $6.5 million in the first quarter of 2016, including production facilities and other related infrastructure, and our most recent Second Bone Spring well in this area was drilled and completed for approximately $4.0 million on an existing multi-well pad, which is the least expensive Second Bone Spring well we have drilled thus far on our Delaware Basin acreage. These well costs are substantially reduced from those of initial wells drilled in this area.

Table of Contents

In mid-2015, the Scott Walker State 36-22S-27E RB #204H well, a Wolfcamp A-XY completion located in the far northwestern portion of our Rustler Breaks prospect area, was completed using our Generation 2 Wolfcamp fracture treatment design with 2,000 pounds of sand per foot of completed lateral and 30 barrels of fracturing fluid per foot of completed lateral. This well tested 504 BOE per day (70% oil), consisting of 354 Bbl of oil per day and 0.9 MMcf of natural gas per day. Although this well did not test at rates as high as our Wolfcamp A-XY tests in the southeastern part of the Rustler Breaks area—the Guitar 10-24S-28E RB #202H and Tiger 14-24S-28E RB #204H wells—we were encouraged by these results as they established the prospectivity of the Wolfcamp A-XY interval across our Rustler Breaks acreage position. To our knowledge, this is the northernmost horizontal test of the Wolfcamp A-XY to date in Eddy County, New Mexico. In late 2015, we tested the Wolfcamp A-XY close to the center of our Rustler Breaks acreage position using our Generation 3 fracture treatment design with up to 3,000 pounds of sand and 40 barrels of fracturing fluid per foot of completed lateral. This well, the Dr. K 24-23S-27E RB #203H, tested 1,241 BOE per day (69% oil), consisting of 856 Bbl of oil per day and 2.3 MMcf of natural gas per day during its 24-hour initial potential test, which further establishes the prospectivity of the Wolfcamp A-XY interval across our Rustler Breaks acreage position. Also, late in 2015, we completed and placed on production two additional wells from the multi-well pad referenced above. One of these wells was the Janie Conner 13-24S-28E RB #224H, a Wolfcamp B completion, which was also stimulated with increased sand concentrations up to 3,000 pounds of sand per foot of completed lateral. During its 24-hour initial potential test, this well flowed 1,703 BOE per day (59% oil), consisting of 1,005 Bbl of oil per day and 4.2 MMcf of natural gas per day, making it the best 24-hour initial potential test of any well we have drilled thus far in the Delaware Basin.

As noted above in "—2015 Highlights—Acquisitions and Divestitures," in the HEYCO Merger we obtained certain oil and natural gas producing properties and undeveloped acreage located in Lea and Eddy Counties, New Mexico, consisting of approximately 58,600 gross (18,200 net) acres strategically located between our existing acreage in our Ranger and Rustler Breaks prospect areas. Most of the acreage from the HEYCO Merger is now included primarily in our Arrowhead prospect area in Eddy County, New Mexico and our Ranger prospect area in Lea County, New Mexico. We did not drill and complete any operated wells in our Arrowhead prospect area in 2015, but we did participate in several non-operated horizontal wells in the Arrowhead prospect area subsequent to the HEYCO Merger, which results illustrate the quality and prospectivity of our acreage in this area. We participated in, or acquired through the HEYCO Merger, four wells operated by an affiliate of Concho Resources Inc. in this area, the CTA State Com #3H, #4H, #5H and #6H wells. These wells were Second Bone Spring completions and tested at an average initial production rate of 956 BOE per day (85% oil). We own an approximate 15% working interest in each of these four wells. We also participated with Mewbourne Oil Company, Inc. in its Gobbler 5 B2PM #1H well in the Arrowhead prospect area. This well, a Second Bone Spring completion, tested 2,300 BOE per day (80% oil), and we own a 6% working interest in this well.

In the Ranger prospect area in Lea County, New Mexico, our first two Second Bone Spring completions have performed above our original projections for this area. As of January 2016, the Ranger State 33-20S-35E RN #121 (formerly the Ranger 33 State Com #1H) had produced 238,000 BOE (91% oil) in its first 26 months of production. The Pickard State 20-18S-34E RN #121H (formerly the Pickard State 20-18-34 #1H), also drilled and completed in the Second Bone Spring, had produced 205,000 BOE (89% oil) in its first 18 months of production. We installed gas-lift assist on the Ranger State 33-20S-35E RN #121 well within its first two months of production, and given the early success of the gas-lift assist on that well, the Pickard State 20-18S-34E RN #121H well was also equipped with gas-lift assist within approximately 30 days of being placed on production. The use of gas-lift assist on these wells in the Ranger prospect area is one example of a transfer of technology and lessons learned from our Eagle Ford shale development program in South Texas to the Delaware Basin. Also in the Ranger prospect area, we drilled and completed the Cimarron 16-19S-34E RN #134H well in the Third Bone Spring formation. During its 24-hour initial potential test, the Cimarron 16-19S-34E RN #134H well flowed 804 BOE per day (94% oil), consisting of 754 Bbl of oil per day and 303 Mcf of natural gas per day. Subsequent to this initial potential test, an electric submersible pump ("ESP") was run in the well to enable it to continue to clean up and produce more efficiently. This was our first use of an ESP in one of our Ranger area wells. After installing the ESP, production from the Cimarron 16-19S-34E RN #134 well increased to over 1,100 BOE per day, and in its first 8.5 months of production as of January 2016, this well produced 123,000 BOE (94% oil). We consider this to be a strong test of the Third Bone Spring, which illustrates the potential for this interval of the Bone Spring as a viable completion target throughout the Ranger prospect area.

During 2015, we also participated in a non-operated Second Bone Spring well offsetting our Pickard State 20-18S-34E RN #121H well. This well, the Iggles 21 State Com #1H, tested 1,300 BOE per day (90% oil), again confirming the prospectivity of the Second Bone Spring in our Ranger prospect area.

In our Twin Lakes prospect area in northern Lea County, New Mexico, we drilled a vertical pilot hole in the fourth quarter of 2015 where we gathered a full suite of openhole well logs and both whole core and rotary sidewall core samples in preparation for drilling our first horizontal well in the Twin Lakes area, which is currently planned for late 2016. At December 31, 2015, we were evaluating the data collected from the vertical pilot hole and evaluating several horizons in the Wolfcamp D as potential horizontal landing targets.

Table of Contents

As a result of our ongoing drilling and completion operations in these prospect areas, our Delaware Basin production increased significantly in 2015. Our average daily oil equivalent production from the Delaware Basin increased 3.6-fold from 1,790 BOE per day, including 1,314 Bbl of oil per day and 2.9 MMcf of natural gas per day, during 2014 to 6,518 BOE per day, including 4,648 Bbl of oil per day and 11.2 MMcf of natural gas per day, during 2015. In addition, our average daily oil equivalent production from the Delaware Basin grew more than three-fold from 2,629 BOE per day in the fourth quarter of 2014 to 8,720 BOE per day in the fourth quarter of 2015. For the year ended December 31, 2015, 26% of our daily oil equivalent production was produced from the Delaware Basin. The Delaware Basin contributed approximately 38% of our daily oil production and approximately 15% of our daily natural gas production during 2015, as compared to only approximately 14% of our daily oil production and approximately 7% of our daily natural gas production during 2014. During the year ended December 31, 2014, only approximately 11% of our daily oil equivalent production was attributable to the Delaware Basin.

At December 31, 2015, approximately 56% of our estimated total proved oil and natural gas reserves, or 47.1 million BOE, was attributable to the Delaware Basin, including approximately 31.4 million Bbl of oil and 94.4 Bcf of natural gas, a 3.6-fold increase, as compared to 13.0 million BOE for the year ended December 31, 2014. Our Delaware Basin proved reserves at December 31, 2015 comprised approximately 69% of our proved oil reserves and 40% of our proved natural gas reserves, as compared to approximately 33% of our proved oil reserves and 11% of our proved natural gas reserves at December 31, 2014. The PV-10 of our proved reserves in the Delaware Basin at December 31, 2015 was $314.6 million, or approximately 58% of the PV-10 of our total proved reserves of $541.6 million. PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10 to Standardized Measure, see "— Estimated Proved Reserves."

At December 31, 2015, we had identified 3,543 gross (1,416.9 net) engineered locations for potential future drilling on our Delaware Basin acreage, primarily in the Wolfcamp or Bone Spring plays, but also including the shallower Avalon and Delaware formations. These locations include 2,263 gross (1,284.1 net) locations that we anticipate operating as we hold a working interest of at least 25% in each of these locations. These engineered locations have been identified on a property-by-property basis and take into account criteria such as anticipated geologic conditions and reservoir properties, estimated rates of return, estimated recoveries from our Delaware Basin wells and other nearby wells based on available public data, drilling densities observed on properties of other operators, estimated horizontal lateral lengths, estimated drilling and completion costs, spacing and other rules established by regulatory authorities and surface considerations, among other criteria. Our engineered well locations at December 31, 2015 do not yet include all portions of our acreage position, including the acreage associated with our Twin Lakes prospect area in Lea County, New Mexico. Our identified well locations presume that these properties may be developed on 80- to 160-acre well spacing, although we believe that denser well spacing may be possible and that multiple intervals may be prospective at any one surface location. As we explore and develop our Delaware Basin acreage further, we anticipate that we may identify additional locations for future drilling. At December 31, 2015, these potential future drilling locations included only 118 gross (71.1 net) locations in the Delaware Basin to which we have assigned proved undeveloped reserves.

At December 31, 2015 and February 25, 2016, we were operating three drilling rigs in the Delaware Basin—two in Loving County, Texas and one in Eddy County, New Mexico. We are also participating in non-operated wells in the Delaware Basin as these opportunities arise. We have allocated approximately $315.0 million, or approximately 97% of our 2016 capital expenditure budget of $325.0 million, to our anticipated drilling, completion and midstream activities in the Delaware Basin, as well as for the acquisition of additional leasehold interests in the area. Our 2016 Delaware Basin drilling and completion program will focus on the development of the Wolf and Rustler Breaks prospect areas and the further delineation and development of our Ranger and Arrowhead prospect areas.

South Texas — Eagle Ford Shale and Other Formations

The Eagle Ford shale extends across portions of South Texas from the Mexican border into East Texas forming a band roughly 50 to 100 miles wide and 400 miles long. The Eagle Ford is an organically rich calcareous shale and lies between the deeper Buda limestone and the shallower Austin Chalk formation. Along the entire length of the Eagle Ford trend, the structural dip of the formation is consistently down to the south with relatively few, modestly sized structural perturbations. As a result, depth of burial increases consistently southwards along with the thermal maturity of the formation. Where the Eagle Ford is shallow, it is less thermally mature and therefore more oil prone, and as it gets deeper and becomes more thermally mature, the Eagle Ford is more natural gas prone. The transition between being more oil prone and more natural gas prone includes an interval that typically produces liquids-rich natural gas with condensate.

At December 31, 2015, our properties included approximately 39,000 gross (29,300 net) acres in the Eagle Ford shale play in Atascosa, DeWitt, Gonzales, Karnes, La Salle, Wilson and Zavala Counties in South Texas. We believe that approximately 88% of our Eagle Ford acreage is prospective predominantly for oil or liquids-rich natural gas with condensate. In addition, we believe that portions of this acreage may also be prospective for other targets, such as the Austin Chalk, Buda, Edwards and Pearsall formations, from which we would expect to produce predominantly oil and liquids. Approximately 82% of our Eagle Ford acreage was held by production at December 31, 2015, and approximately 92% of our Eagle Ford acreage

Table of Contents

was either held by production at December 31, 2015 or not burdened by lease expirations before 2017. In the third quarter of 2015, we acquired approximately 385 gross (385 net) acres in the Eagle Ford shale in Karnes County, Texas adjacent to our Sickenius prospect that we consider to be prospective primarily for oil. We plan to continue our leasing and acquisition efforts in the Eagle Ford shale as strategic opportunities are identified.

At January 1, 2015, we were operating two rigs in the Eagle Ford shale in South Texas, but as a result of both lower oil and natural gas prices in early 2015 and the fact that, at December 31, 2014, approximately 96% of our Eagle Ford acreage was either held by production or not burdened by lease expirations before 2016, we suspended our operated Eagle Ford drilling and completion operations in the second quarter of 2015.

During the year ended December 31, 2015, we completed and began producing oil and natural gas from 18 gross (17.3 net) Eagle Ford shale wells drilled on our acreage position in South Texas, including 17 gross (17.0 net) operated wells and one gross (0.3 net) non-operated well, all in the first few months of 2015. During the second quarter of 2015, our Eagle Ford production increased to its all-time high of 11,942 BOE per day, including 9,358 Bbl of oil per day and 15.5 MMcf of natural gas per day. We completed our planned operated Eagle Ford drilling and completion operations for 2015 in the second quarter, and as a result, our Eagle Ford production declined during the second half of 2015. Despite conducting no operated activity for more than half of 2015, our average daily oil equivalent production from the Eagle Ford shale decreased only 2% from 10,501 BOE per day, including 7,764 Bbl of oil per day and 16.4 MMcf of natural gas per day, during 2014 to 10,263 BOE per day, including 7,642 Bbl of oil per day and 15.7 MMcf of natural gas per day, during 2015. For the year ended December 31, 2015, 41% of our total daily oil equivalent production was attributable to the Eagle Ford shale. During the year ended December 31, 2014, approximately 65% of our daily oil equivalent production was attributable to the Eagle Ford shale.

At December 31, 2015, approximately 22% of our estimated total proved oil and natural gas reserves, or 19.0 million BOE, was attributable to the Eagle Ford shale, including approximately 14.2 million Bbl of oil and 28.8 Bcf of natural gas. Our total proved reserves attributable to the Eagle Ford shale decreased approximately 15% to 19.0 million BOE for the year ended December 31, 2015, as compared to 22.3 million BOE for the year ended December 31, 2014, primarily as a result of declining oil and natural gas prices which resulted in certain previously classified Eagle Ford shale proved undeveloped reserves being reclassified to contingent resources at December 31, 2015. Our Eagle Ford total proved reserves at December 31, 2015 comprised approximately 31% of our proved oil reserves and 12% of our proved natural gas reserves, as compared to approximately 67% of our proved oil reserves and 14% of our proved natural gas reserves at December 31, 2014. The PV-10 of our total proved reserves in the Eagle Ford shale was $175.1 million, or approximately 32% of the PV-10 of our total proved reserves of $541.6 million at December 31, 2015. PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10 to Standardized Measure, see "— Estimated Proved Reserves."

We do not plan to drill any operated Eagle Ford shale wells in 2016, but we have allocated approximately $5.6 million, or about 2%, of our 2016 estimated capital expenditure budget of $325.0 million to the Eagle Ford shale primarily to allow for the installation of pumping units on certain properties and for lease extensions and acquisitions, if desired.

At December 31, 2015, we had identified 260 gross (227.5 net) engineered locations for potential future drilling on our Eagle Ford acreage. These locations have been identified on a property-by-property basis and take into account criteria such as anticipated geologic conditions and reservoir properties, estimated rates of return, estimated recoveries from our producing Eagle Ford wells and other nearby wells based on available public data, drilling densities anticipated on our properties and observed on properties of other operators, estimated horizontal lateral lengths, estimated drilling and completion costs, spacing and other rules established by regulatory authorities and surface considerations, among other factors. The identified well locations presume that we will be able to develop our Eagle Ford properties on 40- to 80-acre spacing, depending on the specific property and the wells we have already drilled. We anticipate the Eagle Ford wells to be drilled on our acreage in central and northern La Salle, northern Karnes and southern Wilson Counties can be developed on 40- to 50-acre spacing, while other properties, particularly the eastern portion of our acreage in DeWitt County, are more likely to be developed on 80-acre spacing. While we do not plan to drill any operated wells in the Eagle Ford in 2016, approximately 92% of our Eagle Ford acreage was either held by production or not burdened by lease expirations before 2017 at December 31, 2015. As a result, these engineered drilling locations remain available to be developed by us at a future time should commodity prices improve, drilling and completion costs decline further or new technologies be developed that increase the expected recoveries. At December 31, 2015, these 260 gross (227.5 net) identified drilling locations included only 27 gross (26.8 net) locations to which we have assigned proved undeveloped reserves.

We believe portions of our Eagle Ford acreage may also be prospective for the Austin Chalk, Buda, Edwards and Pearsall formations, from which we would expect to produce predominantly oil and liquids. In particular, we own approximately 8,900 gross (8,900 net) contiguous acres on our Glasscock Ranch property in southeast Zavala County, Texas, which are held by production and which we believe may be prospective for the Buda formation. At December 31, 2015, we had not drilled any Buda wells nor had we included any Buda locations in our future drilling locations.

Table of Contents

Northwest Louisiana and East Texas

We did not conduct any operated drilling and completion activities on our leasehold properties in Northwest Louisiana and East Texas during 2015, although we did participate in the drilling and completion of 22 gross (1.9 net) non-operated Haynesville shale wells that were turned to sales in 2015. These wells included nine gross (1.6 net) Haynesville wells operated by Chesapeake on our Elm Grove acreage in southern Caddo Parish, Louisiana. In addition, Chesapeake deferred first production until early January 2016 from an additional nine gross (1.9 net) wells drilled and completed in the latter half of 2015 on our Elm Grove acreage. We do not plan to drill any operated Haynesville shale wells in 2016, but we have budgeted capital expenditures of approximately $4.4 million for our anticipated participation in five gross (0.6 net) Haynesville shale wells that we expect to be drilled or completed and placed on production by Chesapeake on certain of our non-operated properties, including Elm Grove, in 2016. Certain of these wells were already in progress at December 31, 2015.

At December 31, 2015, we held approximately 26,700 gross (23,800 net) acres in Northwest Louisiana and East Texas, including 20,700 gross (13,000 net) acres in the Haynesville shale play. We operate all of our Cotton Valley and shallower production on our leasehold interests in Northwest Louisiana and East Texas, as well as all of our Haynesville production on the acreage outside of what we believe to be the core area of the Haynesville shale play. We operate approximately 36% of the 13,700 gross (6,800 net) acres that we consider to be in the core area of the Haynesville play.

For the year ended December 31, 2015, approximately 33% of our average daily oil equivalent production, or 8,174 BOE per day, including 16 Bbl of oil per day and 48.9 MMcf of natural gas per day, was attributable to our leasehold interests in Northwest Louisiana and East Texas. Natural gas production from these properties comprised approximately 64% of our daily natural gas production, but oil production from these properties comprised only about 0.1% of our daily oil production during 2015, as compared to approximately 54% of our daily natural gas production and approximately 0.2% of our daily oil production during 2014. During the year ended December 31, 2014, approximately 24% of our average daily oil equivalent production, or 3,791 BOE per day, including 17 Bbl of oil per day and 22.6 MMcf of natural gas per day, was attributable to our properties in Northwest Louisiana and East Texas. For the year ended December 31, 2015, approximately 61% of our daily natural gas production, or 46.4 MMcf of natural gas per day, was produced from the Haynesville shale, with approximately 3%, or 2.6 MMcf of natural gas per day, produced from the Cotton Valley and other shallower formations on these properties. For the year ended December 31, 2014, approximately 47% of our daily natural gas production, or 19.7 MMcf of natural gas per day, was produced from the Haynesville shale, with approximately 7%, or 2.9 MMcf of natural gas per day, produced from the Cotton Valley and other shallower formations on these properties. At December 31, 2015, approximately 21% of our estimated total proved reserves, or 18.1 million BOE, was attributable to the Haynesville shale with another 1% of our proved reserves, or 0.8 million BOE, attributable to the Cotton Valley and shallower formations underlying this acreage.

At December 31, 2015, we had identified and engineered 448 gross (109.2 net) locations for potential future drilling in the Haynesville shale play and 71 gross (50.1 net) locations for potential future drilling in the Cotton Valley formation. These engineered locations have been identified on a property-by-property basis and take into account criteria such as anticipated geologic conditions and reservoir properties, estimated rates of return, estimated recoveries from our producing Haynesville and Cotton Valley wells and other nearby wells based on available public data, drilling densities observed on properties of other operators, including on some of our non-operated properties, estimated horizontal lateral lengths, estimated drilling and completion costs, spacing and other rules established by regulatory authorities and surface conditions, among other criteria. Of the 448 gross (109.2 net) locations identified for future drilling on our Haynesville acreage, 373 gross (55.3 net) locations have been identified within the 13,700 gross (6,800 net) acres that we believe are located in the core area of the Haynesville play. As we explore and develop our Northwest Louisiana and East Texas acreage further, we believe it is possible that we may identify additional locations for future drilling. At December 31, 2015, these potential future drilling locations included only 26 gross (9.4 net) locations in the Haynesville shale (and no locations in the Cotton Valley) to which we have assigned proved undeveloped reserves.

Haynesville and Middle Bossier Shales

The Haynesville shale is an organically rich, overpressured marine shale found below the Cotton Valley and Bossier formations and above the Smackover formation at depths ranging from 10,500 to 13,500 feet across a broad region throughout Northwest Louisiana and East Texas, including principally Bossier, Caddo, DeSoto and Red River Parishes in Louisiana and Harrison, Rusk, Panola and Shelby Counties in Texas. The Haynesville shale produces primarily dry natural gas with almost no associated liquids. The Bossier shale is overpressured and is often divided into lower, middle and upper units. The Middle Bossier shale appears to be productive for natural gas under large portions of DeSoto, Red River and Sabine Parishes in Louisiana and Shelby and Nacogdoches Counties in Texas, where it shares many similar productive characteristics with the deeper Haynesville shale. Although there is some overlap between the Haynesville and Bossier shale plays, the two plays appear quite distinct and a separate horizontal wellbore is typically needed for each formation.

Table of Contents

At December 31, 2015, we had approximately 20,700 gross (13,000 net) acres in the Haynesville shale play, primarily in Northwest Louisiana. Based on our analysis of geologic and petrophysical information (including total organic carbon content and maturity, resistivity, porosity and permeability, among other information), well performance data, information available to us related to drilling activity and results from wells drilled across the Haynesville shale play, approximately 13,700 gross (6,800 net) acres are located in what we believe is the core area of the play. We believe the core area of the play includes that area in which the most Haynesville wells have been drilled by operators and from which we anticipate natural gas recoveries would likely exceed 6 Bcf per well. Almost all of our Haynesville acreage is held by production or consists of fee mineral interests that we own and portions of it are also producing from and, we believe, prospective for the Cotton Valley, Hosston (Travis Peak) and other shallower formations. In addition, we believe that approximately 1,200 net acres are prospective for the Middle Bossier shale play. We have never drilled a Middle Bossier shale well, and, although we believe that prospective well locations may exist on this acreage, we have not included any Middle Bossier locations in our engineered drilling locations at December 31, 2015.

Within the acreage that we believe to be in the core area of the Haynesville shale play, we are the operator of approximately 2,500 net acres. We have identified 32 gross (24.6 net) potential additional Haynesville locations that we may drill and operate in the future on this acreage. The remainder of our acreage in the core area of the Haynesville shale play is operated by other companies, including our Elm Grove properties in southern Caddo Parish, Louisiana that are operated by Chesapeake following a sale of a portion of our interests there in July 2008. The working interests in our non-operated Haynesville wells are typically small, ranging from less than 1% to more than 30%.

Cotton Valley, Hosston (Travis Peak) and Other Shallower Formations

Prior to initiating natural gas production from the Haynesville shale in 2009, almost all of our production and reserves in Northwest Louisiana and East Texas was attributable to wells producing from the Cotton Valley formation. We own almost all of the shallow rights from the base of the Cotton Valley formation to the surface under our acreage in Northwest Louisiana and East Texas.

All of the shallow rights underlying our acreage in our Elm Grove properties in Northwest Louisiana, approximately 10,000 gross (9,800 net) acres at December 31, 2015, are held by existing production from the Cotton Valley formation or the Haynesville shale. The Cotton Valley formation was the primary producing zone in the Elm Grove field prior to discovery of the Haynesville shale. The Cotton Valley formation is a low permeability natural gas sand that ranges in thickness from 200 to 300 feet and has porosity ranging from 6% to 10%.

We have identified 71 gross (50.1 net) additional drilling locations for future Cotton Valley horizontal wells on our Elm Grove properties. We did not drill any of these locations in 2015 and do not plan to drill any of these locations in 2016. As long as this leasehold acreage is held by existing production from the vertical Cotton Valley wells or the deeper Haynesville shale wells, however, these Cotton Valley natural gas volumes remain available to be developed by us should natural gas prices improve, drilling and completion costs decline or new technologies be developed that increase expected recoveries.

We also continue to hold the shallow rights primarily by existing production on our Central and Southwest Pine Island, Longwood, Woodlawn and other prospect areas in Northwest Louisiana and East Texas. At December 31, 2015, we held an estimated 11,700 gross (9,300 net) leasehold and mineral acres by existing production in these areas.

Southwest Wyoming, Northeast Utah and Southeast Idaho — Meade Peak Shale

At December 31, 2015, we held leasehold interests in approximately 75,700 gross (35,700 net) acres in Southwest Wyoming and adjacent areas in Utah and Idaho as part of a natural gas shale exploration prospect targeting the Meade Peak shale. These leasehold interests are a combination of federal, state and fee mineral interests. We have entered into a participation and joint operating agreement with other parties covering the initial exploration effort on this acreage. We are the operator of this prospect. We have drilled and completed one horizontal well on this acreage, but as of December 31, 2015, we had not established commercial natural gas production on this prospect. We had no production, no proved reserves and no engineered drilling locations attributable to this acreage at December 31, 2015. We have no plans to drill on this acreage in 2016.

12

Table of Contents

Operating Summary

The following table sets forth certain unaudited production data for the years ended December 31, 2015, 2014 and 2013.

	Year Ended December 31,		
	2015	2014	2013
Unaudited Production Data:			
Net Production Volumes:			
Oil (MBbl)	4,492	3,320	2,133
Natural gas (Bcf)	27.7	15.3	12.9
Total oil equivalent (MBOE) (1)	9,109	5,870	4,285
Average daily production (BOE/d) (1)	24,955	16,082	11,740
Average Sales Prices:			
Oil, with realized derivatives (per Bbl)	$59.13	$88.94	$98.67
Oil, without realized derivatives (per Bbl)	$45.27	$87.37	$99.79
Natural gas, with realized derivatives (per Mcf)	$3.24	$5.06	$4.47
Natural gas, without realized derivatives (per Mcf)	$2.71	$5.08	$4.35
Operating Expenses (per BOE):			
Production taxes and marketing	$3.90	$5.65	$4.89
Lease operating	$6.39	$8.75	$9.04
Depletion, depreciation and amortization	$19.63	$22.95	$22.96
General and administrative	$5.50	$5.48	$4.85

(1) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

The following table sets forth information regarding our production volumes, sales prices and production costs for the year ended December 31, 2015 from our operating areas, which we consider to be distinct fields for purposes of accounting for production.

	Southeast New Mexico/West Texas	South Texas	Northwest Louisiana/East Texas		
	Delaware Basin	Eagle Ford (1)	Haynesville	Cotton Valley (2)	Total
Annual Net Production Volumes					
Oil (MBbl)	1,697	2,789	—	6	4,492
Natural gas (Bcf)	4.1	5.7	16.9	1.0	27.7
Total oil equivalent (MBOE) (3)	2,379	3,746	2,822	162	9,109
Percentage of total annual net production	26.1 %	41.1 %	31.0 %	1.8 %	100.0 %
Average Net Daily Production Volumes					
Oil (Bbl/d)	4,648	7,642	—	16	12,306
Natural gas (MMcf/d)	11.2	15.7	46.4	2.6	75.9
Total oil equivalent (BOE/d)	6,518	10,263	7,731	443	24,955
Average Sales Price (4)					
Oil (per Bbl)	$43.54	$46.33	$—	$43.68	$45.27
Natural gas (per Mcf)	$3.00	$3.17	$2.49	$2.45	$2.71
Total oil equivalent (per BOE)	$36.21	$39.35	$14.97	$15.69	$30.56
Production Costs (5)					
	$9.89	$9.35	$4.91	$19.88	$8.29

Lease operating and marketing
(per BOE)

---

(1) Includes one well producing small volumes of oil from the Austin Chalk formation and two wells producing small quantities of natural gas from the San Miguel formation in Zavala County, Texas.
(2) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas.
(3) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.
(4) Excludes impact of derivative settlements.
(5) Excludes ad valorem taxes and oil and natural gas production taxes.

Table of Contents

The following table sets forth information regarding our production volumes, sales prices and production costs for the year ended December 31, 2014 from our operating areas, which we consider to be distinct fields for purposes of accounting for production.

	Southeast New Mexico/West Texas	South Texas	Northwest Louisiana/East Texas		
	Delaware Basin	Eagle Ford [1]	Haynesville	Cotton Valley [2]	Total
Annual Net Production Volumes					
Oil (MBbl)	480	2,834	—	6	3,320
Natural gas (Bcf)	1.0	6.0	7.2	1.1	15.3
Total oil equivalent (MBOE) [3]	653	3,833	1,201	183	5,870
Percentage of total annual net production	11.1 %	65.3 %	20.5 %	3.1 %	100.0 %
Average Net Daily Production Volumes					
Oil (Bbl/d)	1,314	7,764	—	17	9,095
Natural gas (MMcf/d)	2.9	16.4	19.7	2.9	41.9
Total oil equivalent (BOE/d)	1,790	10,501	3,290	501	16,082
Average Sales Price [4]					
Oil (per Bbl)	$80.16	$88.58	$—	$91.24	$87.37
Natural gas (per Mcf)	$4.75	$6.72	$3.87	$4.30	$5.08
Total oil equivalent (per BOE)	$66.41	$75.99	$23.27	$27.92	$62.64
Production Costs [5]					
Lease operating and marketing (per BOE)	$13.11	$10.45	$8.13	$19.09	$10.53

(1) Includes two wells producing small volumes of oil from the Austin Chalk formation and two wells producing small quantities of natural gas from the San Miguel formation in Zavala County, Texas.
(2) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas.
(3) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.
(4) Excludes impact of derivative settlements.
(5) Excludes ad valorem taxes and oil and natural gas production taxes.

Table of Contents

The following table sets forth information regarding our production volumes, sales prices and production costs for the year ended December 31, 2013 from our operating areas, which we consider to be distinct fields for purposes of accounting for production.

	Southeast New Mexico/West Texas	South Texas	Northwest Louisiana/East Texas		
	Delaware Basin	Eagle Ford [1]	Haynesville	Cotton Valley [2]	Total
Annual Net Production Volumes					
Oil (MBbl)	28	2,098	—	6	2,132
Natural gas (Bcf)	—	5.4	6.2	1.3	12.9
Total oil equivalent (MBOE) [3]	31	3,002	1,033	219	4,285
Percentage of total annual net production	0.7 %	70.1 %	24.1 %	5.1 %	100.0 %
Average Net Daily Production Volumes					
Oil (Bbl/d)	78	5,748	—	17	5,843
Natural gas (MMcf/d)	—	14.9	17.0	3.5	35.4
Total oil equivalent (BOE/d)	84	8,225	2,831	600	11,740
Average Sales Price [4]					
Oil (per Bbl)	$90.71	$99.91	$—	$102.13	$99.79
Natural gas (per Mcf)	$5.27	$6.03	$3.05	$3.55	$4.35
Total oil equivalent (per BOE)	$86.51	$80.71	$18.28	$23.61	$62.78
Production Costs [5]					
Lease operating and marketing (per BOE)	$15.68	$11.65	$5.24	$15.39	$10.30

(1) Includes two wells producing small volumes of oil from the Austin Chalk formation and two wells producing small quantities of natural gas from the San Miguel formation in Zavala County, Texas.
(2) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas.
(3) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.
(4) Excludes impact of derivative settlements.
(5) Excludes ad valorem taxes and oil and natural gas production taxes.

Our total oil equivalent production of approximately 9.1 million BOE for the year ended December 31, 2015 increased 55% from our total oil equivalent production of approximately 5.9 million BOE for the year ended December 31, 2014. This increased production was primarily due to our delineation and development operations in the Delaware Basin and new, non-operated Haynesville shale wells completed and placed on production on our Elm Grove properties in Northwest Louisiana during the latter half of 2014 and into 2015, as well as from newly drilled and completed wells in the Eagle Ford shale in early 2015. Our average daily oil equivalent production for the year ended December 31, 2015 was 24,955 BOE per day, as compared to 16,082 BOE per day for the year ended December 31, 2014. Our average daily oil production for the year ended December 31, 2015 was 12,306 Bbl of oil per day, an increase of 35% from 9,095 Bbl of oil per day for the year ended December 31, 2014. Our average daily natural gas production for the year ended December 31, 2015 was 75.9 MMcf of natural gas per day, an increase of 81% from 41.9 MMcf of natural gas per day for the year ended December 31, 2014.

Our total oil equivalent production of approximately 5.9 million BOE for the year ended December 31, 2014 increased 37% from our total oil equivalent production of approximately 4.3 million BOE for the year ended December 31, 2013. This increased production was primarily due to our drilling and completion operations in the Eagle Ford shale, as well as contributions from our initial wells in the Delaware Basin. Our average daily oil equivalent production for the year ended December 31, 2014 was 16,082 BOE per day, as compared to 11,740 BOE per day for the year ended December 31, 2013. Our average daily oil production for the year ended December 31, 2014 was 9,095 Bbl of oil per day, an increase of 56% from 5,843 Bbl of oil per day for the year ended December 31, 2013. Our average daily natural gas production for the year ended December 31, 2014 was 41.9 MMcf of natural gas per day, an increase of 18% from 35.4 MMcf of natural gas per day for the year ended December 31, 2013.

Table of Contents

Producing Wells

The following table sets forth information relating to producing wells at December 31, 2015. Wells are classified as oil wells or natural gas wells according to their predominant production stream. We do not have any currently active dual completions. We have an approximate average working interest of 69% in all wells that we operate at December 31, 2015, as compared to 93% at December 31, 2014, as a result of acquiring producing wells with lower working interests in the Delaware Basin as part of the HEYCO Merger in February 2015. For wells where we are not the operator, our working interests range from less than 1% to as much as just over 50%, and average approximately 10%. In the table below, gross wells are the total number of producing wells in which we own a working interest and net wells represent the total of our fractional working interests owned in the gross wells.

	Oil Wells		Natural Gas Wells		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Southeast New Mexico/West Texas:						
Delaware Basin [(1)]	223	84.9	33	11.1	256	96.0
South Texas:						
Eagle Ford [(2)]	130	111.5	4	4.0	134	115.5
Northwest Louisiana/East Texas:						
Haynesville	—	—	198	18.4	198	18.4
Cotton Valley [(3)]	2	2.0	91	56.4	93	58.4
Area Total	2	2.0	289	74.8	291	76.8
Total	355	198.4	326	89.9	681	288.3

(1) Includes 175 gross (50.6 net) wells acquired in February 2015 as part of the HEYCO Merger.

(2) Includes one well producing small volumes of oil from the Austin Chalk formation and two wells producing small quantities of natural gas from the San Miguel formation in Zavala County, Texas.

(3) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas.

Estimated Proved Reserves

The following table sets forth our estimated proved oil and natural gas reserves at December 31, 2015, 2014 and 2013. Our production and proved reserves are reported in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Where we produce liquids-rich natural gas, such as in the Delaware Basin and the Eagle Ford shale, the economic value of the natural gas liquids associated with the natural gas is included in the estimated wellhead natural gas price on those properties where the natural gas liquids are extracted and sold. The reserves estimates were based on evaluations prepared by our engineering staff and have been audited for their reasonableness by Netherland, Sewell & Associates, Inc., independent reservoir engineers. These reserves estimates were prepared in accordance with the SEC’s rules for oil and natural gas reserves reporting. The estimated reserves shown are for proved reserves only and do not include any unproved reserves classified as probable or possible reserves that might exist for our properties, nor do they include any consideration that could be attributable to interests in unproved and unevaluated acreage beyond those tracts for which proved reserves have been estimated. Proved oil and natural gas reserves are the estimated quantities of crude oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

Table of Contents

	At December 31, [1]		
	2015	2014	2013
Estimated Proved Reserves Data: [2]			
Estimated proved reserves:			
Oil (MBbl)	45,644	24,184	16,362
Natural Gas (Bcf) [3]	236.9	267.1	212.2
Total (MBOE) [4]	85,127	68,693	51,729
Estimated proved developed reserves:			
Oil (MBbl)	17,129	14,053	8,258
Natural Gas (Bcf) [3]	101.4	102.8	53.5
Total (MBOE) [4]	34,037	31,185	17,168
Percent developed	40.0 %	45.4 %	33.2 %
Estimated proved undeveloped reserves:			
Oil (MBbl)	28,515	10,131	8,104
Natural Gas (Bcf) [3]	135.5	164.3	158.7
Total (MBOE) [4]	51,090	37,508	34,561
PV-10 [5] (in millions)	$541.6	$1,043.4	$655.2
Standardized Measure [6] (in millions)	$529.2	$913.3	$578.7

(1) Numbers in table may not total due to rounding.

(2) Our estimated proved reserves, PV-10 and Standardized Measure were determined using index prices for oil and natural gas, without giving effect to derivative transactions, and were held constant throughout the life of the properties. The unweighted arithmetic averages of the first-day-of-the-month prices for the 12 months ended December 31, 2015 were $46.79 per Bbl for oil and $2.59 per MMBtu for natural gas, for the 12 months ended December 31, 2014 were $91.48 per Bbl for oil and $4.35 per MMBtu for natural gas, and for the 12 months ended December 31, 2013 were $93.42 per Bbl for oil and $3.67 per MMBtu for natural gas. These prices were adjusted by lease for quality, energy content, regional price differentials, transportation fees, marketing deductions and other factors affecting the price received at the wellhead. We report our proved reserves in two streams, oil and natural gas, and the economic value of the natural gas liquids associated with the natural gas is included in the estimated wellhead natural gas price on those properties where the natural gas liquids are extracted and sold.

(3) As a result of substantially lower natural gas prices in 2015, we removed approximately 64.3 Bcf (10.7 million BOE) of previously classified proved undeveloped natural gas reserves from our total proved reserves, most of which were attributable to non-operated properties in the Haynesville shale.

(4) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(5) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. PV-10 is not an estimate of the fair market value of our properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies and of the potential return on investment related to the companies' properties without regard to the specific tax characteristics of such entities. Our PV-10 at December 31, 2015, 2014 and 2013 may be reconciled to our Standardized Measure of discounted future net cash flows at such dates by reducing our PV-10 by the discounted future income taxes associated with such reserves. The discounted future income taxes at December 31, 2015, 2014 and 2013 were, in millions, $12.4, $130.1 and $76.5, respectively.

(6) Standardized Measure represents the present value of estimated future net cash flows from proved reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect the timing of future cash flows. Standardized Measure is not an estimate of the fair market value of our properties.

Our estimated total proved oil and natural gas reserves increased 24% from 68.7 million BOE at December 31, 2014 to 85.1 million BOE at December 31, 2015. We added 39.1 million BOE in proved oil and natural gas reserves through extensions and discoveries throughout 2015, approximately 4.3 times our 2015 annual production of 9.1 million BOE. Our proved oil reserves grew 89% from approximately 24.2 million Bbl at December 31, 2014 to approximately 45.6 million Bbl at December 31, 2015. This increase in proved oil reserves is primarily attributable to our drilling program in the Delaware Basin during 2015. Our proved natural gas reserves decreased 11% from 267.1 Bcf at December 31, 2014 to 236.9 Bcf at December 31, 2015. This decrease in proved natural gas reserves was primarily attributable to a decrease in our proved undeveloped natural gas reserves. As a result of substantially lower natural gas prices in 2015, we removed approximately 64.3 Bcf (10.7 million BOE) of previously classified proved undeveloped natural gas reserves from our total proved reserves, most of which were attributable to non-operated properties in the Haynesville shale. As long as the leasehold acreage associated with these previously classified proved undeveloped natural gas reserves is held by production from existing Haynesville wells, however, these natural gas volumes remain available to be developed by us or the operator at a future time should natural gas prices improve, drilling and completion costs decline or new technologies be developed that increase expected recoveries.

The PV-10 of our total proved oil and natural gas reserves decreased 48% from $1.04 billion at December 31, 2014 to $541.6 million at December 31, 2015, as a result of lower oil and natural gas prices. The unweighted arithmetic averages of first-day-of-the-month oil and natural gas prices used to estimate proved reserves at December 31, 2015 were $46.79 per Bbl and $2.59 per MMBtu, a decrease of 49% and 40%, respectively, as compared to average oil and natural gas prices of $91.48 per Bbl and $4.35 per MMBtu used to estimate proved reserves at December 31, 2014. Our total proved reserves at

Table of Contents

December 31, 2015 were made up of approximately 54% oil and 46% natural gas, as compared to 35% oil and 65% natural gas at December 31, 2014.

Our proved developed oil and natural gas reserves increased 9% from 31.2 million BOE at December 31, 2014 to 34.0 million BOE at December 31, 2015 due primarily to our delineation and development operations in the Delaware Basin. Our proved developed oil reserves increased 22% from 14.1 million Bbl at December 31, 2014 to 17.1 million Bbl at December 31, 2015, also primarily as a result of our delineation and development operations in the Delaware Basin. Our proved developed natural gas reserves decreased 1% from 102.8 Bcf at December 31, 2014 to 101.4 Bcf at December 31, 2015, resulting from downward revisions to certain of our proved developed natural gas reserves, primarily in the Haynesville shale, as a result of sharply lower natural gas prices in 2015, and to the 81% increase in our natural gas production to 27.7 Bcf in 2015 as compared to 15.3 Bcf in 2014.

The following table summarizes changes in our estimated proved developed reserves at December 31, 2015.

	Proved Developed Reserves (MBOE) [1]
As of December 31, 2014	31,185
Extensions and discoveries	6,984
Purchases of minerals-in-place	1,180
Revisions of prior estimates	(2,950)
Production	(9,109)
Conversion of proved undeveloped to proved developed	6,747
As of December 31, 2015	34,037

(1) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

Our proved undeveloped oil and natural gas reserves increased from 37.5 million BOE at December 31, 2014 to 51.1 million BOE at December 31, 2015. Our proved undeveloped oil reserves increased from 10.1 million Bbl at December 31, 2014 to 28.5 million Bbl at December 31, 2015, primarily as a result of our delineation and development operations in the Delaware Basin. Our proved undeveloped natural gas reserves decreased from 164.3 Bcf at December 31, 2014 to 135.5 Bcf at December 31, 2015 due primarily to the removal of previously classified proved undeveloped natural gas reserves from our total proved reserves, particularly in the Haynesville shale, as a result of lower natural gas prices in 2015, as noted above.

At December 31, 2015, we had no proved undeveloped reserves in our estimates that remained undeveloped for five years or more following their initial booking, and we currently have plans to use anticipated capital resources to develop the proved undeveloped reserves remaining as of December 31, 2015 within five years of booking these reserves.

The following table summarizes changes in our estimated proved undeveloped reserves at December 31, 2015.

	Proved Undeveloped Reserves (MBOE) [1]
As of December 31, 2014	37,508
Extensions and discoveries	32,151
Purchases of minerals-in-place	409
Revisions of prior estimates	(12,231)
Conversion of proved undeveloped to proved developed	(6,747)
As of December 31, 2015	51,090

(1) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

Table of Contents

The following table sets forth, since 2012, proved undeveloped reserves converted to proved developed reserves during each year and the investments associated with these conversions (dollars in thousands).

	Proved Undeveloped Reserves Converted to Proved Developed Reserves			Investment in Conversion of Proved Undeveloped Reserves to Proved Developed Reserves
	Oil	Natural Gas	Total	
	(MBbl)	(Bcf)	(MBOE) (1)	
2012	283	0.8	415	$ 8,096
2013	2,944	8.3	4,334	115,699
2014	3,780	44.7	11,223	201,950
2015	2,854	23.4	6,747	104,989
Total	9,861	77.2	22,719	$ 430,734

(1) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

The following table sets forth additional summary information by operating area with respect to our estimated net proved reserves at December 31, 2015.

	Net Proved Reserves (1)				
	Oil	Natural Gas	Oil Equivalent	PV-10 (2)	Standardized Measure (3)
	(MBbl)	(Bcf)	(MBOE) (4)	(in millions)	(in millions)
Southeast New Mexico/West Texas:					
Delaware Basin	31,395	94.4	47,124	$314.6	$307.4
South Texas:					
Eagle Ford (5)	14,221	28.8	19,015	175.1	171.1
Northwest Louisiana/East Texas:					
Haynesville	—	108.8	18,148	49.3	48.2
Cotton Valley (6)	28	4.9	840	2.6	2.5
Area Total	28	113.7	18,988	51.9	50.7
Other:					
Wyoming, Utah, Idaho	—	—	—	—	—
Total	45,644	236.9	85,127	$541.6	$529.2

(1) Numbers in table may not total due to rounding.

(2) PV-10 is a non-GAAP financial measure and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. PV-10 is not an estimate of the fair market value of our properties. We and others in the industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies and of the potential return on investment related to the companies' properties without regard to the specific tax characteristics of such entities. Our PV-10 at December 31, 2015 may be reconciled to our Standardized Measure of discounted future net cash flows at such date by reducing our PV-10 by the discounted future income taxes associated with such reserves. The discounted future income taxes at December 31, 2015 were approximately $12.4 million.

(3) Standardized Measure represents the present value of estimated future net cash flows from proved reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect the timing of future cash flows. Standardized Measure is not an estimate of the fair market value of our properties.

(4) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

(5) Includes one well producing small volumes of oil from the Austin Chalk formation and two wells producing small quantities of natural gas from the San Miguel formation in Zavala County, Texas.

(6) Includes the Cotton Valley formation and shallower zones and also includes one well producing from the Frio formation in Orange County, Texas.

Technology Used to Establish Reserves

Under current 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. The term “reasonable certainty” implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. 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

Table of Contents

methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation.

In order to establish reasonable certainty with respect to our estimated proved reserves, we used technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and technical data used in the estimation of our proved reserves include, but are not limited to, electric logs, radioactivity logs, core analyses, geologic maps and available pressure and production data, seismic data and well test data. Reserves for proved developed producing wells were estimated using production performance and material balance methods. Certain new producing properties with little production history were forecast using a combination of production performance and analogy to offset production. Non-producing reserves estimates for both developed and undeveloped properties were forecast using either volumetric and/or analogy methods.

Internal Control Over Reserves Estimation Process

We maintain an internal staff of petroleum engineers and geoscience professionals to ensure the integrity, accuracy and timeliness of the data used in our reserves estimation process. Our Senior Vice President of Reservoir Engineering and Chief Technology Officer is primarily responsible for overseeing the preparation of our reserves estimates. He received his Bachelor and Master of Science degrees in Petroleum Engineering from Texas A&M University, is a Licensed Professional Engineer in the State of Texas and has over 38 years of industry experience. Following the preparation of our reserves estimates, these estimates are audited for their reasonableness by Netherland, Sewell & Associates, Inc., independent reservoir engineers. The Operations and Engineering Committee of our Board of Directors reviews the reserves report and our reserves estimation process, and the results of the reserves report and the independent audit of our reserves are reviewed by other members of our Board of Directors, including members of our Audit Committee.

Acreage Summary

The following table sets forth the approximate acreage in which we held a leasehold, mineral or other interest at December 31, 2015.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Southeast New Mexico/West Texas:						
Delaware Basin	73,494	30,814	83,639	57,936	157,133	88,750
South Texas:						
Eagle Ford	28,910	23,431	10,125	5,824	39,035	29,255
Northwest Louisiana/East Texas:						
Haynesville	17,343	9,644	3,364	3,363	20,707	13,007
Cotton Valley	18,189	16,111	3,586	3,074	21,775	19,185
Area Total (1)	22,634	20,315	4,030	3,517	26,663	23,831
Other:						
Wyoming, Utah, Idaho	1,600	800	74,074	34,932	75,674	35,732
Total	126,638	75,360	171,868	102,209	298,505	177,568

(1) Some of the same leases cover the gross and net acreage shown for both the Haynesville formation and the shallower Cotton Valley formation. Therefore, the sum of the gross and net acreage for both formations is not equal to the total gross and net acreage for Northwest Louisiana and East Texas.

Undeveloped Acreage Expiration

The following table sets forth the approximate number of gross and net undeveloped acres at December 31, 2015 that will expire over the next three years by operating area unless production is established within the spacing units covering the acreage prior to the expiration dates, the existing leases are renewed prior to expiration or continued operations maintain the leases beyond the expiration of each respective primary term. Undeveloped acreage expiring in 2019 and beyond represents an immaterial amount of our overall undeveloped acreage.

20

Table of Contents

	Acres Expiring 2016		Acres Expiring 2017		Acres Expiring 2018	
	Gross	Net	Gross	Net	Gross	Net
Southeast New Mexico/West Texas:						
Delaware Basin (1)	34,235	21,175	17,188	10,336	18,045	14,077
South Texas:						
Eagle Ford (2)	2,633	2,435	2,510	2,484	477	477
Northwest Louisiana/East Texas:						
Haynesville	524	523	—	—	—	—
Cotton Valley	80	80	—	—	—	—
Area Total (3)	524	523	—	—	—	—
Other:						
Wyoming, Utah, Idaho	—	—	21,874	9,575	48,859	24,605
Total	37,392	24,133	41,572	22,395	67,381	39,159

(1) Approximately 60% of the acreage expiring in 2016 is associated with our Twin Lakes prospect area in northern Lea County, New Mexico. Most of these leases can be extended for an additional two years, should we choose to do so, by paying an additional lease bonus. We also expect to hold or extend portions of the remaining expiring acreage outside of our Twin Lakes prospect area in 2016 through our 2016 drilling activities or by paying an additional lease bonus, where applicable.
(2) We expect to extend portions of our expiring Eagle Ford acreage in 2016 by paying an additional lease bonus.
(3) Some of the same leases cover the gross and net acreage shown for both the Haynesville formation and the shallower Cotton Valley formation. Therefore, the sum of the gross and net acreage for both formations is not equal to the total gross and net acreage for Northwest Louisiana and East Texas.

Many of the leases comprising the acreage set forth in the table above will expire at the end of their respective primary terms unless operations are conducted which will serve to maintain the respective leases in effect beyond the expiration of the primary term or production from the acreage has been established prior to such date, in which event the lease will remain in effect until the cessation of production in commercial quantities in most cases. We also have options to extend some of our leases through payment of additional lease bonus payments prior to the expiration of the primary term of the leases. In addition, we may attempt to secure a new lease upon the expiration of certain of our acreage; however, there may be third party leases that become effective immediately if our leases expire at the end of their respective terms and production has not been established prior to such date or operations are not conducted to maintain the leases in effect beyond the primary term. As of December 31, 2015, our leases are primarily fee and state leases with primary terms of three to five years. As a result of the HEYCO Merger in 2015, we also have acquired a significant number of federal leases with primary terms of 10 years; however, essentially all of the federal leases acquired in the HEYCO Merger are held by production. We believe that our lease terms are similar to our competitors' fee lease terms as they relate to both primary term and royalty interests.

Drilling Results

The following table summarizes our drilling activity for the years ended December 31, 2015, 2014 and 2013.

	Year Ended December 31,					
	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	53	26.7	89	39.9	32	20.7
Dry	—	—	—	—	—	—
Exploration Wells						
Productive	28	17.5	12	10.6	14	8.7
Dry (1)	—	—	—	—	1	0.4

Total Wells						
Productive	81	44.2	101	50.5	46	29.4
Dry [1]	—	—	—	—	1	0.4

(1) We participated on a non-operated basis in an unsuccessful vertical well test of the Edwards formation on our Atascosa County, Texas acreage in 2013.

Table of Contents

Marketing

Our crude oil is generally sold under short-term, extendable and cancellable agreements with unaffiliated purchasers based on published price bulletins reflecting an established field posting price. As a consequence, the prices we receive for crude oil and a portion of our heavier liquids move up and down in direct correlation with the oil market as it reacts to supply and demand factors. The prices of the remaining lighter liquids move up and down independently of any relationship between the crude oil and natural gas markets. Transportation costs related to moving crude oil and liquids are also deducted from the price received for crude oil and liquids.

Our natural gas is sold under both long-term and short-term natural gas purchase agreements. Natural gas produced by us is sold at various delivery points at or near producing wells to both unaffiliated independent marketing companies and unaffiliated midstream companies. We receive proceeds from prices that are based on various pipeline indices less any associated fees. When there is an opportunity to do so, the midstream companies may, at our request, process our natural gas at a processing facility and extract liquid hydrocarbons from the natural gas. We are then paid for the extracted liquids based on either a negotiated percentage of the proceeds that are generated from the midstream companies' sale of the liquids, or other negotiated pricing arrangements using then-current market pricing less fixed rate processing, transportation and fractionation fees.

The prices we receive for our oil and natural gas production fluctuate widely. Factors that cause price fluctuations include the level of demand for oil and natural gas, the actions of OPEC, weather conditions, hurricanes in the Gulf Coast region, oil and natural gas storage levels, domestic and foreign governmental regulations, price and availability of alternative fuels, political conditions in oil and natural gas producing regions, the domestic and foreign supply of oil and natural gas, the price of foreign imports and overall economic conditions. Decreases in these commodity prices adversely affect the carrying value of our proved reserves and our revenues, profitability and cash flows. Short-term disruptions of our oil and natural gas production occur from time to time due to downstream pipeline system failure, capacity issues and scheduled maintenance, as well as maintenance and repairs involving our own well operations. These situations, if they occur, curtail our production capabilities and ability to maintain a steady source of revenue. In addition, demand for natural gas has historically been seasonal in nature, with peak demand and typically higher prices during the colder winter months. See "Risk Factors — Our Success Is Dependent on the Prices of Oil and Natural Gas. Low Oil or Natural Gas Prices and the Substantial Volatility in These Prices May Adversely Affect Our Financial Condition and Our Ability to Meet Our Capital Expenditure Requirements and Financial Obligations."

For the year ended December 31, 2015, we had three significant purchasers that accounted for approximately 59% of our total oil, natural gas and natural gas liquids revenues. For the years ended December 31, 2014 and 2013, we had three and five significant purchasers that accounted for approximately 68% and 87%, respectively, of our total oil, natural gas and natural gas liquids revenues. Due to the nature of the markets for oil, natural gas and natural gas liquids, we do not believe that the loss of any one of these purchasers would have a material adverse impact on our financial condition, results of operations or cash flows for any significant period of time.

Effective September 1, 2012, we entered into a firm five-year natural gas processing and transportation agreement whereby we committed to transport the anticipated natural gas production from a significant portion of our Eagle Ford acreage in South Texas through the counterparty's system for processing at the counterparty's facilities. The agreement also includes firm transportation of the natural gas liquids extracted at the counterparty's processing plant downstream for fractionation. After processing, the residue natural gas is purchased by the counterparty at the tailgate of its processing plant and further transported under its natural gas transportation agreements. The arrangement contains fixed processing and liquids transportation and fractionation fees, and the revenue we receive varies with the quality of natural gas transported to the processing facilities and the contract period.

Under this natural gas processing and transportation agreement, if we do not meet 80% of the maximum thermal quantity transportation and processing commitments in a contract year, we will be required to pay a deficiency fee per MMBtu of natural gas deficiency. Any quantity in excess of the maximum MMBtu delivered in a contract year can be carried over to the next contract year for purposes of calculating the natural gas deficiency. During certain prior periods, we had an immaterial natural gas deficiency and the counterparty to this agreement waived the deficiency fee. See "Risk Factors — The Marketability of Our Production Is Dependent upon Oil and Natural Gas Gathering, Processing and Transportation Facilities Owned and Operated by Third Parties, and the Unavailability of Satisfactory Oil and Natural Gas Gathering, Processing and Transportation Arrangements Would Have a Material Adverse Effect on Our Revenue."

As part of the sale of the Loving County System (See Note 5 to the consolidated financial statements in this Annual Report on Form 10-K), we entered into a 15-year fixed-fee natural gas gathering and processing agreement whereby we committed to deliver the anticipated natural gas production from a significant portion of our Loving County, Texas acreage in West Texas through the counterparty's gathering system for processing at the counterparty's facility. Under this agreement, if we do not meet the volume commitment for transportation and processing at the facility in a contract year, we will be required to pay a deficiency fee per MMBtu of natural gas deficiency. At the end of each year of the agreement, we can elect to have the previous year's actual transportation and processing commitment be the new minimum commitment for each of the remaining years of the contract. As such, we have the ability to unilaterally reduce the transportation and processing commitment if our production in the Loving County area is less than our currently projected production. If we ceased operations in this area at December 31, 2015, the total deficiency fee required to be paid would be approximately $9.6 million. In addition, if we elect to reduce the transportation and processing commitment in any year, we have the ability to elect to increase the committed volumes in any future year to the originally agreed transportation and processing commitment. Any quantity in excess of the volume commitment delivered in a contract year can be carried over to the next contract year for purposes of calculating the natural gas deficiency. We paid approximately $1.8 million in processing and transportation fees under this agreement during the year ended December 31, 2015. We can elect to either sell the residue gas to the counterparty at the tailgate of its processing plant or have the counterparty deliver to us the residue gas in-kind to be sold to third parties downstream of the plant. See "Risk Factors — The Marketability of Our Production Is Dependent upon Oil and Natural Gas Gathering, Processing and Transportation Facilities Owned and Operated by Third Parties, and the Unavailability of Satisfactory Oil and Natural Gas Gathering, Processing and Transportation Arrangements Would Have a Material Adverse Effect on Our Revenue."

Title to Properties

We endeavor to assure that title to our properties is in accordance with standards generally accepted in the oil and natural gas industry. Some of our acreage will be obtained through farmout agreements, term assignments and other contractual arrangements with third parties, the terms of which often will require the drilling of wells or the undertaking of other exploratory or development activities in order to retain our interests in the acreage. Our title to these contractual interests will be contingent upon our satisfactory fulfillment of these obligations. Our properties are also subject to customary royalty interests, liens incident to financing arrangements, operating agreements, taxes and other burdens that we believe will not materially interfere with the use and operation of or affect the value of these properties. We intend to maintain our leasehold interests by conducting operations, making lease rental payments or producing oil and natural gas from wells in paying quantities, where required, prior to expiration of various time periods to avoid lease termination. Certain of the leases that we have obtained to date have been purchased by and in the name of professional lease brokers as our nominee. See "Risk Factors — We May Incur Losses or Costs as a Result of Title Deficiencies in the Properties in Which We Invest."

Seasonality

Generally, but not always, the demand and price levels for natural gas increase during winter months and decrease during summer months. To lessen seasonal demand fluctuations, pipelines, utilities, local distribution companies and industrial users utilize natural gas storage facilities and forward purchase some of their anticipated winter requirements during the summer. However, increased summertime demand for electricity can place increased demand on storage volumes. Demand for oil and heating oil is also generally higher in the winter and the summer driving season, although oil prices are impacted more significantly by global supply and demand. Seasonal anomalies, such as mild winters, sometimes lessen these fluctuations. Certain of our drilling, completion and other operations are also subject to seasonal limitations.

Competition

The oil and natural gas industry is highly competitive. We compete and will continue to compete with major and independent oil and natural gas companies for exploration opportunities, acreage and property acquisitions. We also compete for drilling rig contracts and other equipment and labor required to drill, operate and develop our properties. Many of our competitors have substantially greater financial resources, staffs, facilities and other resources. In addition, larger competitors may be able to absorb the burden of any changes in federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. These competitors may be willing and able to pay more for drilling rigs or exploratory prospects and productive oil and natural gas properties and may be able to identify, evaluate, bid for and purchase a greater number of properties and prospects than we can. Our competitors may also be able to afford to purchase and operate their own drilling rigs and hydraulic fracturing equipment.

Our ability to drill and explore for oil and natural gas and to acquire properties will depend upon our ability to conduct operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. We have been conducting field operations since 2004 while many of our competitors may have a longer history of operations. Additionally, most of our competitors have demonstrated the ability to operate through industry cycles.

The oil and natural gas industry also competes with other energy-related industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers. See “Risk Factors — Competition in the Oil and Natural Gas Industry Is Intense, Making It More Difficult for Us to Acquire Properties, Market Oil and Natural Gas and Secure Trained Personnel.”

Table of Contents

Regulation

Oil and Natural Gas Regulation

Our oil and natural gas exploration, development, production and related operations are subject to extensive federal, state and local laws, rules and regulations. Failure to comply with these laws, rules and regulations can result in substantial monetary penalties or delay or suspension of operations. The regulatory burden on the oil and natural gas industry increases our cost of doing business and affects our profitability. Because these laws, rules and regulations are frequently amended or reinterpreted and new laws, rules and regulations are promulgated, we are unable to predict the future cost or impact of complying with the laws, rules and regulations to which we are, or will become, subject. Our competitors in the oil and natural gas industry are generally subject to the same regulatory requirements and restrictions that affect our operations. We cannot predict the impact of future government regulation on our properties or operations.

Texas, New Mexico, Louisiana, Wyoming, Idaho, Utah and many other states require permits for drilling operations, drilling bonds and reports concerning operations and impose other requirements relating to the exploration, development and production of oil and natural gas. Many states also have statutes or regulations addressing conservation of oil and natural gas and other matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from wells, the regulation of well spacing, the surface use and restoration of properties upon which wells are drilled, the prohibition or restriction on venting or flaring natural gas, the sourcing and disposal of water used in the drilling and completion process and the plugging and abandonment of these wells. Many states restrict production to the market demand for oil and natural gas. Some states have enacted statutes prescribing ceiling prices for natural gas sold within their boundaries. Additionally, some regulatory agencies have, from time to time, imposed price controls and limitations on production by restricting the rate of flow of oil and natural gas wells below natural production capacity in order to conserve supplies of oil and natural gas. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction.

Some of our oil and natural gas leases are issued by agencies of the federal government, as well as agencies of the states in which we operate. These leases contain various restrictions on access and development and other requirements that may impede our ability to conduct operations on the acreage represented by these leases.

Our sales of natural gas, as well as the revenues we receive from our sales, are affected by the availability, terms and costs of transportation. The rates, terms and conditions applicable to the interstate transportation of natural gas by pipelines are regulated by the Federal Energy Regulatory Commission, or FERC, under the Natural Gas Act of 1938, or the NGA, as well as under Section 311 of the Natural Gas Policy Act of 1978, or the NGPA. Since 1985, FERC has implemented regulations intended to increase competition within the natural gas industry by making natural gas transportation more accessible to natural gas buyers and sellers on an open-access, non-discriminatory basis. The natural gas industry has historically, however, been heavily regulated and we can give no assurance that the current less stringent regulatory approach of FERC will continue.

In 2005, Congress enacted the Domenici-Barton Energy Policy Act of 2005, or the Energy Policy Act. The Energy Policy Act, among other things, amended the NGA to prohibit market manipulation by any entity, to direct FERC to facilitate market transparency in the market for the sale or transportation of physical natural gas in interstate commerce and to significantly increase the penalties for violations of the NGA, the NGPA or FERC rules, regulations or orders thereunder. FERC has promulgated regulations to implement the Energy Policy Act. Should we violate the anti-market manipulation laws and related regulations, in addition to FERC-imposed penalties, we may also be subject to third-party damage claims.

Intrastate natural gas transportation is subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Because these regulations will apply to all intrastate natural gas shippers within the same state on a comparable basis, we believe that the regulation in any states in which we operate will not affect our operations in any way that is materially different from our competitors that are similarly situated.

Natural gas gathering facilities are exempt from the jurisdiction of FERC under section 1(b) of the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to FERC jurisdiction. State regulation of gathering facilities generally includes various safety, environmental and, in some circumstances, nondiscriminatory take requirements, and in some instances complaint-based rate regulation.

The price we receive from the sale of oil and natural gas liquids will be affected by the availability, terms and cost of transportation of the products to market. Under rules adopted by FERC, interstate oil pipelines can change rates based on an inflation index, though other rate mechanisms may be used in specific circumstances. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions, which varies from state to state. We are not able to predict with certainty the effects, if any, of these regulations on our operations.

Table of Contents

In 2007, the Energy Independence & Security Act of 2007, or the EISA, went into effect. The EISA, among other things, prohibits market manipulation by any person in connection with the purchase or sale of crude oil, gasoline or petroleum distillates at wholesale in contravention of such rules and regulations that the Federal Trade Commission may prescribe, directs the Federal Trade Commission to enforce the regulations and establishes penalties for violations thereunder. We cannot predict any future laws or regulations or their impact.

U.S. Federal and State Taxation

The federal, state and local governments in the areas in which we operate impose taxes on the oil and natural gas products we sell and, for many of our wells, sales and use taxes on significant portions of our drilling and operating costs. Many states have raised state taxes on energy sources or state taxes associated with the extraction of hydrocarbons, and additional increases may occur. In addition, there has been a significant amount of discussion by legislators and presidential administrations concerning a variety of energy tax proposals. President Obama has proposed sweeping changes to federal laws on the income taxation of small oil and natural gas exploration and production companies like ours. Among other issues, President Obama has proposed to eliminate allowing small U.S. oil and natural gas companies to deduct intangible drilling costs as incurred and percentage depletion. Changes to tax laws could adversely affect our business and our financial results. See “Risk Factors — We Are Subject to Federal, State and Local Taxes, and May Become Subject to New Taxes or Have Eliminated or Reduced Certain Federal Income Tax Deductions Currently Available with Respect to Oil and Natural Gas Exploration and Production Activities as a Result of Future Legislation, Which Could Adversely Affect Our Business, Financial Condition, Results of Operations and Cash Flows.”

Hydraulic Fracturing Policies and Procedures

We use hydraulic fracturing as a means to maximize the recovery of oil and natural gas in almost every well that we drill and complete. Our engineers responsible for these operations attend specialized hydraulic fracturing training programs taught by industry professionals. Although average drilling and completion costs for each area will vary, as will the cost of each well within a given area, on average approximately one-half to two-thirds of the total well costs for our horizontal wells are attributable to overall completion activities, which are primarily focused on hydraulic fracture treatment operations. These costs are treated in the same way that all other costs of drilling and completion of our wells are treated and are built into and funded through our normal capital expenditure budget. A change to any federal and state laws and regulations governing hydraulic fracturing could impact these costs and adversely affect our business and financial results. See “Risk Factors — Federal and State Legislation and Regulatory Initiatives Relating to Hydraulic Fracturing Could Result in Increased Costs and Additional Operating Restrictions or Delays.”

The protection of groundwater quality is important to us. We believe that we follow all state and federal regulations and apply industry standard practices for groundwater protection in our operations. These measures are subject to close supervision by state and federal regulators (including the Bureau of Land Management (“BLM”) with respect to federal acreage).

Although rare, if and when the cement and steel casing used in well construction requires remediation, we deal with these problems by evaluating the issue and running diagnostic tools, including cement bond logs, temperature logs and pressure testing, followed by pumping remedial cement jobs and other appropriate remedial measures.

The vast majority of hydraulic fracturing treatments are made up of water and sand or other kinds of man-made propping agents. We use major hydraulic fracturing service companies who track and report chemical additives that are used in the fracturing operation as required by the appropriate governmental agencies. These service companies fracture stimulate thousands of wells each year for the industry and invest millions of dollars to protect the environment through rigorous safety procedures, and also work to develop more environmentally friendly fracturing fluids. We also follow safety procedures and monitor all aspects of the fracturing operation in an attempt to ensure environmental protection. We do not pump any diesel in the fluid systems of any of our fracture stimulation procedures.

While current fracture stimulation procedures utilize a significant amount of water, we typically recover less than 10% of this fracture stimulation water before produced salt water becomes a significant portion of the fluids produced. All produced water, including fracture stimulation water, is disposed of in permitted and regulated disposal facilities in a

way that is designed to avoid any impact to surface waters.
Environmental Regulation
The exploration, development and production of oil and natural gas, including the operation of salt water injection and disposal wells, are subject to various federal, state and local environmental laws and regulations. These laws and regulations can increase the costs of planning, designing, drilling, completing and operating oil and natural gas wells. Our activities are subject to a variety of environmental laws and regulations, including but not limited to: the Oil Pollution Act of 1990, or the OPA 90, the Clean Water Act, or the CWA, the Comprehensive Environmental Response, Compensation and Liability Act, or CERCLA, the Resource Conservation and Recovery Act, or RCRA, the Clean Air Act, or the CAA, the Safe Drinking Water Act, or the SDWA, and the Occupational Safety and Health Act, or OSHA, as well as comparable state statutes and regulations.

We are also subject to regulations governing the handling, transportation, storage and disposal of wastes generated by our activities and naturally occurring radioactive materials, or NORM, that may result from our oil and natural gas operations. Administrative, civil and criminal fines and penalties may be imposed for noncompliance with these environmental laws and regulations. Additionally, these laws and regulations require the acquisition of permits or other governmental authorizations before undertaking some activities, limit or prohibit other activities because of protected wetlands, areas or species and require investigation and cleanup of pollution. We expect to remain in compliance in all material respects with currently applicable environmental laws and regulations and expect that these laws and regulations will not have a material adverse impact on us.

The OPA 90 and its regulations impose requirements on “responsible parties” related to the prevention of crude oil spills and related to liability for damages resulting from oil spills into or upon navigable waters, adjoining shorelines or in the exclusive economic zone of the United States. A “responsible party” under the OPA 90 may include the owner or operator of an onshore facility. The OPA 90 subjects responsible parties to strict, joint and several financial liability for removal costs and other damages, including natural resource damages, caused by an oil spill that is covered by the statute. It also imposes other requirements on responsible parties, such as the preparation of an oil spill contingency plan. Failure to comply with the OPA 90 may subject a responsible party to civil or criminal enforcement action. We may conduct operations on acreage located near, or that affects, navigable waters subject to the OPA 90. We believe that compliance with applicable requirements under the OPA 90 will not have a material adverse effect on us.

The CWA and comparable state laws impose restrictions and strict controls regarding the discharge of produced waters, fill materials and other materials into navigable waters. These controls have become more stringent over the years, and it is possible that additional restrictions will be imposed in the future. Permits are required to discharge pollutants into certain state and federal waters and to conduct construction activities in those waters and wetlands. Certain state regulations and the general permits issued under the federal National Pollutant Discharge Elimination System program prohibit the discharge of produced water, produced sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into certain coastal and offshore waters. Further, the U.S. Environmental Protection Agency, or the EPA, has adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The CWA and comparable state statutes provide for civil, criminal and administrative penalties for any unauthorized discharges of oil and other pollutants and impose liability for the costs of removal or remediation of contamination resulting from such discharges. In furtherance of the CWA, the EPA promulgated the Spill Prevention, Control, and Countermeasure regulations, which require certain oil-storing facilities to prepare plans and meet construction and operating standards.

CERCLA, also known as the “Superfund” law, imposes liability, without regard to fault or the legality of the original conduct, on various classes of persons that are considered to have contributed to the release of a “hazardous substance” into the environment. These persons include the owner or operator of the disposal site where the release occurred and companies that disposed of, or arranged for the disposal of, the hazardous substances found at the site. Persons who are responsible for releases of hazardous substances under CERCLA may be subject to joint and several liability for the costs of cleaning up the hazardous substances and for damages to natural resources. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances released into the environment. Although CERCLA generally exempts petroleum from the definition of hazardous substances, our operations may, and in all likelihood will, involve the use or handling of materials that may be classified as hazardous substances under CERCLA. Many states have adopted similar statutes. Certain state statutes may impose liability for a broader range of contaminants and may not contain a similar exemption for petroleum. Furthermore, we may acquire or operate properties that unknown to us have been subjected to, or have caused or contributed to, prior releases of hazardous substances or other materials requiring remediation.

RCRA and comparable state and local statutes govern the management, including treatment, storage and disposal, of both hazardous and nonhazardous solid wastes. We generate hazardous and nonhazardous solid waste in connection with our routine operations. At present, RCRA includes a statutory exemption that allows many wastes associated with crude oil and natural gas exploration and production to be classified as nonhazardous waste. A similar exemption is contained in many of the state counterparts to RCRA. Not all of the wastes we generate fall within these exemptions. At various times in the past, proposals have been made to amend RCRA to eliminate the exemption applicable to crude oil and natural gas exploration and production wastes. Repeal or modifications of this exemption by administrative, legislative or judicial process, or through changes in applicable state statutes, would increase the volume of hazardous waste we are required to manage and dispose of and would cause us, as well as our competitors, to incur increased operating expenses. Hazardous wastes are subject to more stringent and costly disposal requirements than are nonhazardous wastes.

The CAA, as amended, and comparable state laws restrict the emission of air pollutants from many sources, including oil and natural gas production. These laws and any implementing regulations impose stringent air permit requirements and require us to obtain pre-approval for the construction or modification of certain projects or facilities expected to produce air emissions, or to use specific equipment or technologies to control emissions. On April 17, 2012, the EPA issued final rules to subject oil and natural gas operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS, programs under the CAA, and to impose new and amended requirements under both programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells. Since January 1, 2015, operators must capture the natural gas and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to new hydraulically fractured wells and also existing wells that are refractured. Further, the finalized regulations also established specific requirements, effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment. These rules have required changes to our operations, including the installation of new equipment to control emissions. Further, in August 2015, the EPA issued proposed NSPS governing methane emissions from the oil and natural gas industry as well as proposed source determination standards for determining when oil and natural gas sources should be aggregated for CAA permitting and compliance purposes. The proposed NSPS for methane would extend the 2012 NSPS to remaining equipment and processes not currently regulated under the existing standards, including completions of hydraulically fractured oil wells, equipment leaks, pneumatic pumps and natural gas compressor station compressors. We continue to evaluate the effect these proposed rules would have on our business and operations. On January 22, 2016, the Department of the Interior proposed rules relating to the venting, flaring and leaking of natural gas by oil and natural gas producers who operate on federal and Indian lands. The proposed rules would, among other things, limit routine flaring of natural gas, require the payment of royalties on avoidable gas losses and require plans or programs relating to gas capture and leak detection and repair. The proposed rules are still in the period for public comment. These rules could increase our operating costs and have a material adverse effect on our business and operations.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly waste handling, storage, transport, disposal, cleanup or operating requirements could materially adversely affect our operations and financial condition, as well as those of the oil and natural gas industry in general. For instance, recent scientific studies have suggested that emissions of certain gases, commonly referred to as “greenhouse gases,” and including carbon dioxide and methane, may be contributing to the warming of the Earth’s atmosphere. As a result, there have been attempts to pass comprehensive greenhouse gas legislation. To date, such legislation has not been enacted. In addition, ongoing international discussions are exploring options to succeed the Kyoto Protocol, most recently at the United Nations Conference on climate change in Paris in November-December 2015. These discussions could result in a legally binding international agreement to make certain global emissions reductions at a national level, which in turn could further drive regulation in the United States. Any future international agreements, federal laws or implementing regulations that may be adopted to address greenhouse gas emissions could, and in all likelihood would, require us to incur increased operating costs adversely affecting our profits and could adversely affect demand for the oil and natural gas we produce, depressing the prices we receive for oil and natural gas.

The EPA has adopted rules under the CAA for the permitting of greenhouse gas emissions from stationary sources under the Prevention of Significant Deterioration (“PSD”) and Title V permitting programs. The EPA has adopted a multi-tiered approach to this permitting, with the largest sources first subject to permitting. In addition, reporting of greenhouse gas emissions from onshore oil and natural gas production was first required on an annual basis in 2012 for emissions occurring in 2011. The adoption and implementation of any regulations imposing reporting obligations on, or limiting emissions of greenhouse gases from, our equipment and operations could, and in all likelihood will, require us to incur costs to reduce emissions of greenhouse gases associated with our operations adversely affecting our profits or could adversely affect demand for the oil and natural gas we produce, depressing the prices we receive for oil and natural gas.

Some states have begun taking actions to control and/or reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or state or regional greenhouse gas cap-and-trade programs. Although most of the state-level initiatives have to date focused on significant sources of greenhouse gas emissions, such as coal-fired electric plants, it is possible that less significant sources of emissions could become subject to greenhouse gas emission limitations or emissions allowance purchase requirements in the future. Any one of these climate change regulatory and legislative initiatives could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Underground injection is the subsurface placement of fluid through a well, such as the reinjection of brine produced and separated from oil and natural gas production. In our industry, underground injection not only allows us to economically dispose of produced water, but if injected into an oil bearing zone, it can increase the oil production from such zone. The SDWA establishes a regulatory framework for underground injection, the primary objective of which is to ensure the mechanical integrity of the injection apparatus and to prevent migration of fluids from the injection zone into underground sources of drinking water. The disposal of hazardous waste by underground injection is subject to stricter requirements than the disposal of produced water. As of December 31, 2015, we owned and operated nine underground injection wells and owned but did not operate two underground injection wells through a less-than-wholly-owned subsidiary, and we expect to own and operate similar wells in the future. Failure to obtain, or abide by, the requirements for the issuance of necessary permits could subject us to civil and/or criminal enforcement actions and penalties. In addition, in some instances, the operation of underground injection wells has been alleged to cause earthquakes (induced seismicity) as a result of flawed well design or

Table of Contents

operation. This has resulted in stricter regulatory requirements in some jurisdictions relating to the location and operation of underground injection wells. We do not expect these developments to have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our activities involve the use of hydraulic fracturing. For more information on our hydraulic fracturing operations, see "— Hydraulic Fracturing Policies and Procedures." Recently, there has been increasing regulatory scrutiny of hydraulic fracturing, which is generally exempted from regulation as underground injection (unless diesel is a component of the fracturing fluid) on the federal level pursuant to the SDWA. However, the U.S. Senate and House of Representatives have considered legislation to repeal this exemption. If enacted, these proposals would amend the definition of "underground injection" in the SDWA to encompass hydraulic fracturing activities. If enacted, such a provision could require hydraulic fracturing operations to meet permitting and financial assurance requirements, adhere to certain construction specifications, fulfill monitoring, reporting and recordkeeping obligations and meet plugging and abandonment requirements. These legislative proposals have also contained language to require the reporting and public disclosure of chemicals used in the hydraulic fracturing process. If the exemption for hydraulic fracturing is removed from the SDWA, or if other legislation is enacted at the federal, state or local level, any restrictions on the use of hydraulic fracturing contained in any such legislation could have a significant impact on our financial condition, results of operations and cash flows.

In addition, some states and localities have placed additional regulatory burdens upon hydraulic fracturing activities and, in some areas, severely restricted or prohibited those activities. At the state level, Texas, New Mexico and Wyoming, for example, have enacted requirements for the disclosure of the composition of the fluids used in hydraulic fracturing. In addition, at least a few state and local governments or regional authorities have imposed temporary moratoria on drilling permits. For example, in December 2014, New York announced a moratorium on high volume fracturing activities combined with horizontal drilling following the issuance of a study regarding the safety of hydraulic fracturing. Certain communities in Colorado have also enacted bans on hydraulic fracturing within city limits. These actions are the subject of legal challenges. Additional burdens upon hydraulic fracturing, such as reporting or permitting requirements, will result in additional expense and delay in our operations.

The EPA has asserted federal regulatory authority over hydraulic fracturing using diesel under the SDWA's Underground Injection Control Program. The EPA issued SDWA permitting guidance for hydraulic fracturing operations involving the use of diesel fuel in fracturing fluids in those states where the EPA is the permitting authority. Although we do not currently pump diesel in the fluid systems of any of our fracture stimulation procedures, any such change in our practices may cause us to be subject to this guidance. In addition, in June 2015, the EPA issued draft results of its study on the effects of hydraulic fracturing on drinking water resources. The EPA did not find evidence of widespread, systemic impacts on drinking water resources in the United States, although it did note a lack of data in many areas. Further, the BLM issued final rules to regulate hydraulic fracturing on federal lands in March 2015, although these rules have been temporarily stayed by the federal district court for the District of Wyoming pending litigation. The EPA has also announced an Advance Notice of Proposed Rulemaking under the Toxic Substance Control Act to develop regulations governing the disclosure of hydraulic fracturing chemicals.

Oil and natural gas exploration and production, operations and other activities have been conducted at some of our properties by previous owners and operators. Materials from these operations remain on some of the properties, and, in some instances, require remediation. In addition, we occasionally must agree to indemnify sellers of producing properties from whom we acquire the properties against some of the liability for environmental claims associated with the properties. While we do not believe that costs we incur for compliance with environmental regulations and remediating previously or currently owned or operated properties will be material, we cannot provide any assurances that these costs will not result in material expenditures that adversely affect our profitability.

Additionally, in the course of our routine oil and natural gas operations, surface spills and leaks, including casing leaks, of oil or other materials will occur, and we will incur costs for waste handling and environmental compliance. It is also possible that our oil and natural gas operations may require us to manage NORM. NORM is present in varying concentrations in sub-surface formations, including hydrocarbon reservoirs, and may become concentrated in scale, film and sludge in equipment that comes in contact with crude oil and natural gas production and processing streams.

Some states, including Texas,
have enacted regulations governing the handling, treatment, storage and disposal of NORM. Moreover, we will be able to control directly the operations of only those wells for which we act as the operator. Despite our lack of control over wells owned partly by us but operated by others, the failure of the operator to comply with the applicable environmental regulations may, in certain circumstances, be attributable to us.

We are subject to the requirements of OSHA and comparable state statutes. The OSHA Hazard Communication Standard, the "community right-to-know" regulations under Title III of the federal Superfund Amendments and Reauthorization Act and similar state statutes require us to organize information about hazardous materials used, released or produced in our operations. Certain of this information must be provided to employees, state and local governmental authorities and local citizens. We are also subject to the requirements and reporting set forth in OSHA workplace standards.

Table of Contents

The Endangered Species Act, or ESA, was established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The U.S. Fish and Wildlife Service must also designate the species' critical habitat and suitable habitat as part of the effort to ensure survival of the species. A critical habitat or suitable habitat designation could result in material restrictions on land use and may materially impact oil and natural gas development. Our oil and natural gas operations in certain of our operating areas could also be adversely affected by seasonal or permanent restrictions on drilling activity designed to protect certain wildlife in the Delaware Basin. See "Risk Factors—We Are Subject to Government Regulation and Liability, Including Complex Environmental Laws, Which Could Require Significant Expenditures." Our ability to maximize production from our leases may be adversely impacted by these restrictions.

We have not in the past been, and do not anticipate in the near future to be, required to expend amounts that are material in relation to our total capital expenditures as a result of environmental laws and regulations, but since these laws and regulations are periodically amended, we are unable to predict the ultimate cost of compliance. We have no assurance that more stringent laws and regulations protecting the environment will not be adopted or that we will not otherwise incur material expenses in connection with environmental laws and regulations in the future. See "Risk Factors — We Are Subject to Government Regulation and Liability, Including Complex Environmental Laws, Which Could Require Significant Expenditures."

The clear trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. The EPA has announced that one of its enforcement initiatives for 2014 to 2016 is to focus on compliance by the energy extraction sector. Any changes in environmental laws and regulations or re-interpretation of enforcement policies that result in more stringent and costly waste handling, storage, transport, disposal or remediation requirements could have a material adverse effect on our operations and financial condition. We may be unable to pass on such increased compliance costs to our customers. Moreover, accidental releases or spills may occur in the course of our operations, and we have no assurance that we will not incur significant costs and liabilities as a result of such releases or spills, including any third party claims for damage to property, natural resources or persons.

We maintain insurance against some, but not all, potential risks and losses associated with our industry and operations. We do not currently carry business interruption insurance. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. If a significant accident or other event occurs and is not fully covered by insurance, it could materially adversely affect our financial condition, results of operations and cash flows.

Office Lease

Our corporate headquarters are located at One Lincoln Centre, 5400 LBJ Freeway, Suite 1500, Dallas, Texas 75240. See Note 13 to the consolidated financial statements in this Annual Report on Form 10-K for more details regarding our office lease. Such information is incorporated herein by reference.

Employees

At December 31, 2015, we had 151 full-time employees. We believe that our relationships with our employees are satisfactory. No employee is covered by a collective bargaining agreement. From time to time, we use the services of independent consultants and contractors to perform various professional services, particularly in the areas of geology and geophysics, production operations, construction, design, well site surveillance and supervision, permitting and environmental assessment and legal and income tax preparation and accounting services. Independent contractors, at our request, drill all of our wells and usually perform field and on-site production operation services for us, including facilities construction, pumping, maintenance, dispatching, inspection and testing. If significant opportunities for company growth arise and require additional management and professional expertise, we will seek to employ qualified individuals to fill positions where that expertise is necessary to develop those opportunities.

Available Information

Our Internet website address is www.matadorresources.com. We make available, free of charge, through our website, our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports, as soon as reasonably practicable after providing such reports to the SEC. Also, the charters of our

Audit Committee, Corporate Governance Committee, Executive Committee and Nominating, Compensation and Planning Committee, and our Code of Ethics and Business Conduct for Officers, Directors and Employees, are available through our website, and we also intend to disclose any amendments to our Code of Ethics and Business Conduct, or waivers to such code on behalf of our Chief Executive Officer, Chief Financial Officer or Chief Accounting Officer, on our website. All of these corporate governance materials are available free of charge and in print to any shareholder who provides a written request to the Corporate Secretary at One Lincoln Centre, 5400 LBJ Freeway, Suite 1500, Dallas, Texas 75240. The contents of our website are not intended to be incorporated by reference into this Annual Report on Form 10-K or any other report or document we file and any reference to our website is intended to be an inactive textual reference only.

Item 1A. Risk Factors.

Risks Related to the Oil and Natural Gas Industry and Our Business

Our Success Is Dependent on the Prices of Oil and Natural Gas. Continued Low Oil and Natural Gas Prices and the Continued Volatility in These Prices May Adversely Affect Our Financial Condition and Our Ability to Meet Our Capital Expenditure Requirements and Financial Obligations.

The prices we receive for our oil and natural gas heavily influence our revenue, profitability, cash flow available for capital expenditures, access to capital, borrowing capacity under our Credit Agreement and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile and will likely continue to be volatile in the future. During 2015, the average price of oil was $48.79 per Bbl, ranging from a high of $61.43 per Bbl in mid-June to a low of $34.73 per Bbl in late December based upon the NYMEX West Texas Intermediate oil futures contract price for the earliest delivery date, and the average price of natural gas was $2.63 per MMBtu, ranging from a high of $3.23 per MMBtu in mid-January to a low of $1.76 per MMBtu in mid-December based upon the NYMEX Henry Hub natural gas futures contract price for the earliest delivery date. Throughout 2015, oil and natural gas prices continued to decline sharply from their most recent highs in 2014. Oil prices have decreased 68% from $107.26 per Bbl in mid-June 2014 to $34.73 per Bbl in late December 2015, and natural gas prices have decreased 71% from $6.15 per MMBtu in mid-February 2014 to $1.76 per MMBtu in mid-December 2015. These sharp declines in oil and natural gas prices impacted our revenues, profitability and cash flows in 2015, as compared to 2014, and further declines in the prices of oil or natural gas could have an adverse impact on our borrowing capacity, ability to obtain additional capital, revenues, profitability and cash flows.

Further, because we use the full-cost method of accounting, we perform a ceiling test quarterly that may be impacted by declining prices of oil and natural gas. Significant price declines caused us to recognize full-cost ceiling impairments in each quarter of 2015, and continued low prices may cause us to recognize further full-cost ceiling impairments. Such full-cost ceiling impairments reduce the book value of our net tangible assets, retained earnings and shareholders' equity but do not impact our cash flows from operations, liquidity or capital resources. See "—We May Be Required to Write Down the Carrying Value of Our Proved Properties under Accounting Rules and These Write-Downs Could Adversely Affect Our Financial Condition."

The prices we receive for our production, and the levels of our production, depend on numerous factors. These factors include, but are not limited to, the following:

- the domestic and foreign supply of, and demand for, oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC, and state-controlled oil companies relating to oil price and production controls;
- the prices and availability of competitors' supplies of oil and natural gas;
- the price and quantity of foreign imports;
- the impact of U.S. dollar exchange rates on oil and natural gas prices;
- domestic and foreign governmental regulations and taxes;
- speculative trading of oil and natural gas futures contracts;
- the availability, proximity and capacity of gathering, processing and transportation systems for natural gas;
- the availability of refining capacity;
- the prices and availability of alternative fuel sources;
- weather conditions and natural disasters;
- political conditions in or affecting oil and natural gas producing regions or countries, including the United States, Middle East, South America and Russia;

- the continued threat of terrorism and the impact of military action and civil unrest;

Table of Contents

- public pressure on, and legislative and regulatory interest within, federal, state and local governments to stop, significantly limit or regulate hydraulic fracturing activities;
- the level of global oil and natural gas inventories and exploration and production activity;
- the impact of energy conservation efforts;
- technological advances affecting energy consumption; and
- overall worldwide economic conditions.

These factors make it difficult to predict future commodity price movements with any certainty. Substantially all of our oil and natural gas sales are made in the spot market or pursuant to contracts based on spot market prices and are not pursuant to long-term fixed price contracts. Further, oil prices and natural gas prices do not necessarily fluctuate in direct relation to each other.

Declines in oil or natural gas prices not only reduce our revenue, but could also reduce the amount of oil and natural gas that we can produce economically and could reduce the amount we may borrow under our Credit Agreement. Should oil or natural gas prices decrease to economically unattractive levels and remain at economically unattractive levels for an extended period of time, we may elect in the future to delay some of our exploration and development plans for our prospects, or to cease exploration or development activities on certain prospects due to the anticipated unfavorable economics from such activities, each of which could have a material adverse effect on our business, financial condition, results of operations and reserves. For example, if oil prices drop and remain below $30.00 per Bbl, we have the flexibility to reduce the number of rigs we are operating from three rigs to two rigs, either for a short time or for the remainder of 2016, beginning as early as the second quarter of 2016. In addition, such declines in commodity prices could cause a reduction in our borrowing base. If the borrowing base were to be less than the outstanding borrowings under our Credit Agreement at any time, we would be required to provide additional collateral satisfactory in nature and value to the lenders to increase the borrowing base to an amount sufficient to cover such excess or repay the deficit in equal installments over a period of six months.

Our Exploration, Development and Exploitation Projects Require Substantial Capital Expenditures That May Exceed Our Cash Flows from Operations and Potential Borrowings, and We May Be Unable to Obtain Needed Capital on Satisfactory Terms, Which Could Adversely Affect Our Future Growth.

Our exploration and development activities are capital intensive. We make and expect to continue to make substantial capital expenditures in our business for the exploration, development, exploitation, production and acquisition of oil and natural gas reserves. Our cash, operating cash flows and potential future borrowings under our Credit Agreement or otherwise may not be sufficient to fund all of our future acquisitions or future capital expenditures. The rate of our future growth is dependent, at least in part, on our ability to access capital at rates and on terms we determine to be acceptable.

We may sell additional equity securities or issue additional debt securities to raise capital. If we succeed in selling additional equity securities or securities convertible into equity securities to raise funds or make acquisitions, the ownership of our existing shareholders would be diluted, and new investors may demand rights, preferences or privileges senior to those of existing shareholders. If we raise additional capital through the issuance of new debt securities or additional indebtedness, we may become subject to additional covenants that restrict our business activities.

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

- our estimated proved oil and natural gas reserves;
- the amount of oil and natural gas we produce from existing wells;
- the prices at which we sell our production;
- the costs of developing and producing our oil and natural gas reserves;
- our ability to acquire, locate and produce new reserves;
- the ability and willingness of banks to lend to us; and
- our ability to access the equity and debt capital markets.

In addition, the possible occurrence of future events, such as further decreases in the prices of oil and natural gas, or extended periods of such decreased prices, terrorist attacks, wars or combat peace-keeping missions, financial market disruptions, general economic recessions, oil and natural gas industry recessions, large company bankruptcies, accounting scandals, overstated reserves estimates by major public oil companies and disruptions in the financial and capital markets, has caused financial institutions, credit rating agencies and the public to more closely review the financial statements, capital structures and earnings of public companies, including energy companies. Such events have constrained the capital available to the energy industry in the past, and such events or similar events could adversely affect our access to funding for our operations in the future.

If our revenues continue to decrease as a result of lower oil and natural gas prices, operating difficulties, declines in reserves or the value thereof or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels, further develop and exploit our current properties or invest in certain exploration opportunities. Alternatively, to fund acquisitions, increase our rate of growth, develop our properties or pay for higher service costs, we may decide to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of production payments, the sale of midstream or other assets, the borrowing of funds or otherwise to meet any increase in capital spending. If we are unable to raise additional capital from available sources at acceptable terms, our business, financial condition and future results of operations could be adversely affected.

Drilling for and Producing Oil and Natural Gas Are Highly Speculative and Involve a High Degree of Operational and Financial Risk, with Many Uncertainties That Could Adversely Affect Our Business.

Exploring for and developing hydrocarbon reserves involves a high degree of operational and financial risk, which precludes us from definitively predicting the costs involved and time required to reach certain objectives. Our drilling locations are in various stages of evaluation, ranging from locations that are ready to drill to locations that will require substantial additional interpretation before they can be drilled. The budgeted costs of planning, drilling, completing and operating wells are often exceeded and such costs can increase significantly due to various complications that may arise during drilling, completion and operation. Before a well is spud, we may incur significant geological and geophysical (seismic) costs, which are incurred whether or not a well eventually produces commercial quantities of hydrocarbons, or is drilled at all. Exploration wells bear a much greater risk of loss than development wells. The analogies we draw from available data from other wells, more fully explored locations or producing fields may not be applicable to our drilling locations. If our actual drilling and development costs are significantly more than our estimated costs, we may not be able to continue our operations as proposed and could be forced to modify our drilling plans accordingly.

If we decide to drill a certain location, there is a risk that no commercially productive oil or natural gas reservoirs will be found or produced. We may drill or participate in new wells that are not productive. We may drill wells that are productive, but that do not produce sufficient net revenues to return a profit after drilling, operating and other costs. There is no way to affirmatively determine in advance of drilling and testing whether any particular location will yield oil or natural gas in sufficient quantities to recover exploration, drilling and completion costs or to be economically viable. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon-bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production and reserves from, or abandonment of, the well. The productivity and profitability of a well may be negatively affected by a number of additional factors, including the following:

- general economic and industry conditions, including the prices received for oil and natural gas;
- shortages of, or delays in, obtaining equipment, including hydraulic fracturing equipment, and qualified personnel;
- potential drainage by operators on adjacent properties;
- loss of or damage to oilfield development and service tools;
- accidents, equipment failures or mechanical problems;
- problems with title to the underlying properties;
- increases in severance taxes;
- adverse weather conditions that delay drilling activities or cause producing wells to be shut in;
- domestic and foreign governmental regulations; and
- proximity to and capacity of gathering, processing and transportation facilities.

Furthermore, our operations involve using some of the latest drilling and completion techniques developed by us and our service providers. For example, risks that we face while drilling and completing horizontal wells include, but are not limited to, the following:

- landing our wellbore in the desired drilling zone;

- staying in the desired drilling zone while drilling horizontally through the formation;
- running our casing the entire length of the wellbore;
- fracture stimulating the planned number of stages; and

Table of Contents

- being able to run tools and other equipment consistently through the horizontal wellbore.

If we do not drill productive and profitable wells in the future, our business, financial condition, results of operations, cash flows and reserves could be materially and adversely affected.

The Borrowing Base under Our Credit Agreement is Subject to Periodic Redetermination.

The borrowing base under the Credit Agreement is determined semi-annually as of May 1 and November 1 by the lenders based primarily on the estimated value of our proved oil and natural gas reserves at December 31 and June 30 of each year, respectively. Both we and the lenders may request an unscheduled redetermination of the borrowing base once each between scheduled redetermination dates. In addition, our lenders have the flexibility to reduce our borrowing base due to factors beyond our control. As of February 25, 2016, our borrowing base was $375.0 million, and we had no outstanding borrowings and approximately $0.6 million in outstanding letters of credit issued pursuant to the Credit Agreement. At December 31, 2015, the PV-10 of our proved oil and natural gas reserves was $541.6 million, as compared to $1.04 billion at December 31, 2014. We could be required to repay a portion of our bank debt to the extent that, after a redetermination, our outstanding borrowings at such time exceeded the redetermined borrowing base. We may not have sufficient funds to make such repayments, which could result in a default under the terms of the Credit Agreement and an acceleration of the loans thereunder requiring us to negotiate renewals, arrange new financing or sell significant assets, all of which could have a material adverse effect on our business and financial results.

The Terms of the Agreements Governing Our Outstanding Indebtedness May Restrict Our Current and Future Operations, Particularly Our Ability to Respond to Changes in Business or to Take Certain Actions.

Our Credit Agreement and the indenture governing our senior notes contain, and any future indebtedness we incur will likely contain, a number of restrictive covenants that impose significant operating and financial restrictions, including restrictions on our ability to engage in acts that may be in our best long-term interest. One or more of these agreements include covenants that, among other things, restrict our ability to:

- incur or guarantee additional debt or issue certain types of preferred stock;
- pay dividends on capital stock or redeem, repurchase or retire our capital stock or subordinated indebtedness;
- transfer or sell assets;
- make certain investments;
- create certain liens;
- enter into agreements that restrict dividends or other payments from our Restricted Subsidiaries (as defined in the indenture) to us;
- consolidate, merge or transfer all or substantially all of our assets;
- engage in transactions with affiliates; and
- create unrestricted subsidiaries.

A breach of any of these covenants could result in an event of default under our Credit Agreement and the indenture governing our outstanding senior notes. For example, our Credit Agreement requires us to maintain a debt to EBITDA ratio, which is defined as total debt outstanding divided by a rolling four quarter EBITDA calculation, of 4.25 or less. Continued low oil and natural gas prices or any further decline in the prices of oil or natural gas may adversely impact our EBITDA, cash flows and debt levels, and therefore our ability to comply with this covenant. Upon the occurrence of such an event of default, all amounts outstanding under the applicable debt agreements could be declared to be immediately due and payable and all applicable commitments to extend further credit could be terminated. If indebtedness under our Credit Agreement or indenture is accelerated, there can be no assurance that we will have sufficient assets to repay such indebtedness. The operating and financial restrictions and covenants in these debt agreements and any future financing agreements could adversely affect our ability to finance future operations or capital needs or to engage in other business activities.

We May Not Be Able to Generate Sufficient Cash to Service All of Our Indebtedness and May Be Forced to Take Other Actions to Satisfy Our Obligations under Applicable Debt Instruments, Which May Not Be Successful.

Our ability to make scheduled payments on or to refinance our indebtedness obligations depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain

financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness.
If our cash flows and capital resources are insufficient to fund debt service obligations, we may be forced to reduce or delay investments and capital expenditures, sell assets, seek additional capital or restructure or refinance indebtedness. Our

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

We May Incur Additional Indebtedness Which Could Reduce Our Financial Flexibility, Increase Interest Expense and Adversely Impact Our Operations and Our Unit Costs.

At February 25, 2016, we had available borrowings of approximately $374.4 million under our Credit Agreement (after giving effect to outstanding letters of credit). Our borrowing base is determined semi-annually by our lenders based primarily on the estimated value of our existing and future oil and natural gas reserves, but both we and our lenders can request one unscheduled redetermination between scheduled redetermination dates. Our Credit Agreement is secured by our interests in the majority of our oil and natural gas properties, and contains covenants restricting our ability to incur additional indebtedness, sell assets, pay dividends and make certain investments. Since the borrowing base is subject to periodic redeterminations, if a redetermination resulted in a lower borrowing base, we could be required to provide additional collateral satisfactory in nature and value to the lenders to increase the borrowing base to an amount sufficient to cover such excess or repay the deficit in equal installments over a period of six months. If we are required to do so, we may not have sufficient funds to fully make such repayments.

In the future, subject to the restrictions in the indenture governing our outstanding senior notes and in other instruments governing our other outstanding indebtedness (including our Credit Agreement) we may incur significant amounts of additional indebtedness, including under our Credit Agreement or through the issuance of additional notes, in order to fund acquisitions, develop our properties or invest in certain exploration opportunities. Interest rates on such future indebtedness may be higher than current levels, causing our financing costs to increase accordingly.

A high level of indebtedness could affect our operations in several ways, including the following:

- requiring a significant portion of our cash flows to be used for servicing our indebtedness;
- increasing our vulnerability to general adverse economic and industry conditions;
- placing us at a competitive disadvantage compared to our competitors that are less leveraged and, therefore, may be able to take advantage of opportunities that our level of indebtedness may prevent us from pursuing;
- restricting our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and general corporate or other purposes; and
- increasing the risk that we may default on our debt obligations.

Our Credit Rating May be Downgraded Which Could Reduce Our Financial Flexibility, Increase Interest Expense and Adversely Impact Our Operations.

As of February 25, 2016, our corporate credit rating from Standard & Poor’s Rating Services was “B” and our corporate credit rating from Moody’s Investors Service was “B2.” We cannot assure you that our credit ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Similar to many of our competitors and other companies in the energy industry, in January 2016, our credit rating was placed under review by Moody’s Investors Service due to the possible effects of continued depressed oil and natural gas prices. Any future downgrade could increase the cost of any indebtedness incurred in the future.

Any increase in our financing costs resulting from a credit rating downgrade could adversely affect our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions and general corporate or other purposes. If a credit rating downgrade were to occur at a time when we were experiencing significant working capital requirements or otherwise lacked liquidity, our results of operations could be materially adversely affected.

Table of Contents

Our Operations Are Subject to Operational Hazards and Unforeseen Interruptions for Which We May Not Be Adequately Insured.

There are numerous operational hazards inherent in oil and natural gas exploration, development, production and gathering, including:

- natural disasters;
- adverse weather conditions;
- loss of drilling fluid circulation;
- blowouts where oil or natural gas flows uncontrolled at a wellhead;
- cratering or collapse of the formation;
- pipe or cement leaks, failures or casing collapses;
- fires or explosions;
- releases of hazardous substances or other waste materials that cause environmental damage;
- pressures or irregularities in formations; and
- equipment failures or accidents.

In addition, there is an inherent risk of incurring significant environmental costs and liabilities in the performance of our operations, some of which may be material, due to our handling of petroleum hydrocarbons and wastes, our emissions to air and water, the underground injection or other disposal of our wastes, the use of hydraulic fracturing fluids and historical industry operations and waste disposal practices. Any of these or other similar occurrences could result in the disruption or impairment of our operations, substantial repair costs, personal injury or loss of human life, significant damage to property, environmental pollution and substantial revenue losses. The location of our wells, gathering systems, pipelines and other facilities near populated areas, including residential areas, commercial business centers and industrial sites, could significantly increase the level of damages resulting from these risks.

Insurance against all operational risks is not available to us. We are not fully insured against all risks, including development and completion risks that are generally not recoverable from third parties or insurance. Pollution and environmental risks generally are not fully insurable. In addition, we may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the perceived risks presented. Losses could, therefore, occur for uninsurable or uninsured risks or in amounts in excess of existing insurance coverage. Moreover, insurance may not be available in the future at commercially reasonable prices or on commercially reasonable terms. Changes in the insurance markets due to various factors may make it more difficult for us to obtain certain types of coverage in the future. As a result, we may not be able to obtain the levels or types of insurance we would otherwise have obtained prior to these market changes, and the insurance coverage we do obtain may not cover certain hazards or all potential losses that are currently covered, and may be subject to large deductibles. Losses and liabilities from uninsured and underinsured events and delays in the payment of insurance proceeds could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Because Our Reserves and Production Are Concentrated in a Few Core Areas, Problems in Production and Markets Relating to a Particular Area Could Have a Material Impact on Our Business.

Almost all of our current oil and natural gas production and our proved reserves are attributable to our properties in the Delaware Basin in Southeast New Mexico and West Texas, the Eagle Ford shale in South Texas and the Haynesville shale in Northwest Louisiana and East Texas. For the year ended December 31, 2015, approximately 26% of our total oil and natural gas production, including approximately 38% of our average daily oil production, was attributable to our properties in the Delaware Basin and approximately 41% of our total oil and natural gas production, including approximately 62% of our average daily oil production, was attributable to our properties in the Eagle Ford shale. At December 31, 2015, approximately 58% of the PV-10 of our total proved oil and natural gas reserves and approximately 69% of our total proved oil reserves were attributable to our properties in the Delaware Basin, and approximately 32% of the PV-10 of our total proved oil and natural gas reserves and approximately 31% of our total proved oil reserves were attributable to our properties in South Texas, primarily in the Eagle Ford shale. We expect that almost all of our operations in 2016 will be in the Delaware Basin.

The industry focus on the Delaware Basin and the Eagle Ford shale may adversely impact our ability to transport and process our oil and natural gas production due to significant competition for gathering systems, pipelines, processing facilities and oil and condensate trucking operations. For example, infrastructure constraints have in the past required, and may in the future require, us to flare natural gas occasionally, decreasing the volumes sold from our wells. In connection with the sale of the Loving County System, in October 2015, we entered into a 15-year fixed-fee natural gas gathering and processing

Table of Contents

agreement covering the anticipated natural gas production from a significant portion of our acreage in the Delaware Basin in West Texas. In addition, we have a firm natural gas processing and transportation agreement covering the anticipated natural gas production from a significant portion of our Eagle Ford shale acreage in South Texas, which expires in September 2017. However, due to the concentration of our operations we may be disproportionately exposed to the impact of delays or interruptions of production from our wells in our operating areas caused by transportation capacity constraints or interruptions, curtailment of production, availability of equipment, facilities, personnel or services, significant governmental regulation, natural disasters, adverse weather conditions or plant closures for scheduled maintenance.

Our operations may also be adversely affected by weather conditions and events such as hurricanes, tropical storms and inclement winter weather, resulting in delays in drilling and completions, damage to facilities and equipment and the inability to receive equipment or access personnel and products at affected job sites in a timely manner. For example, during the fourth quarters of 2014 and 2015, the Delaware Basin experienced severe winter weather that impacted many operators. In particular, the weather conditions and freezing temperatures resulted in power outages, curtailments in trucking, delays in drilling and completion of wells and other production constraints. In the third quarter of 2014, certain areas of the Delaware Basin experienced severe flooding that impacted our operations as well as many other operators in the area, resulting in delays in drilling, completing and initiating production on certain wells. As we continue to focus our operations on the Delaware Basin, we may increasingly face these and other challenges posed by severe weather.

Due to the concentrated nature of our portfolio of properties, a number of our properties could experience any of the same conditions at the same time, resulting in a relatively greater impact on our results of operations than they might have on other companies that have a more diversified portfolio of properties. For example, our operations in the Delaware Basin are subject to particular restrictions on drilling activities based on environmental sensitivities and requirements and potash mining operations. Such delays, interruptions or restrictions could have a material adverse effect on our financial condition, results of operations and cash flows.

The Unavailability or High Cost of Drilling Rigs, Completion Equipment and Services, Supplies and Personnel, Including Hydraulic Fracturing Equipment and Personnel, Could Adversely Affect Our Ability to Establish and Execute Exploration and Development Plans within Budget and on a Timely Basis, Which Could Have a Material Adverse Effect on Our Financial Condition, Results of Operations and Cash Flows.

Shortages or the high cost of drilling rigs, completion equipment and services, personnel or supplies, including sand and other proppants, could delay or adversely affect our operations. When drilling activity in the United States increases, associated costs typically also increase, including those costs related to drilling rigs, equipment, supplies, including sand and other proppants, and personnel and the services and products of other industry vendors. These costs may increase, and necessary equipment, supplies and services may become unavailable to us at economical prices. Should this increase in costs occur, we may delay drilling activities, which may limit our ability to establish and replace reserves, or we may incur these higher costs, which may negatively affect our business, financial condition, results of operations and cash flows. In addition, should low oil or natural gas prices continue or should oil and natural gas prices decline further, third-party service providers may face financial difficulties and be unable to provide services. A reduction in the number of service providers available to us may negatively impact our ability to retain qualified service providers, or obtain such services at costs acceptable to us.

In addition, the demand for hydraulic fracturing services from time to time exceeds the availability of fracturing equipment and crews across the industry and in certain operating areas in particular. The accelerated wear and tear of hydraulic fracturing equipment due to its deployment in unconventional oil and natural gas fields characterized by longer lateral lengths and larger numbers of fracturing stages could further amplify such an equipment and crew shortage. If demand for fracturing services were to increase or the supply of fracturing equipment and crews were to decrease, higher costs could result, which could adversely affect our business, financial condition, results of operations and cash flows.

If We Are Unable to Acquire Adequate Supplies of Water for Our Drilling and Hydraulic Fracturing Operations or Are Unable to Dispose of the Water We Use at a Reasonable Cost and Pursuant to Applicable Environmental Rules, Our Ability to Produce Oil and Natural Gas Commercially and in Commercial Quantities Could Be Impaired.

We use a substantial amount of water in our drilling and hydraulic fracturing operations. Our inability to obtain sufficient amounts of water at reasonable prices, or treat and dispose of water after drilling and hydraulic fracturing, could adversely impact our operations. In recent years, Southeast New Mexico and West Texas have experienced severe drought. As a result, we may experience difficulty in securing the necessary volumes of water for our operations. Moreover, the imposition of new environmental initiatives and regulations 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 and production of oil and natural gas. Furthermore, future environmental regulations and permitting requirements governing the withdrawal, storage and use of surface water or groundwater necessary for hydraulic fracturing of wells could increase operating costs and cause delays, interruptions or termination of operations, the

Table of Contents

extent of which cannot be predicted, all of which could have an adverse effect on our business, financial condition, results of operations and cash flows.

Unless We Replace Our Oil and Natural Gas Reserves, Our Reserves and Production Will Decline, Which Would Adversely Affect Our Business, Financial Condition, Results of Operations and Cash Flows.

The rate of production from our oil and natural gas properties declines as our reserves are depleted. Our future oil and natural gas reserves and production and, therefore, our income and cash flow, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional oil and natural gas producing properties. We are currently focusing primarily on increasing our production and reserves from the Delaware Basin, an area in which our competitors have been active. As a result of this activity, we may have difficulty expanding our current production or acquiring new properties in this area and may experience such difficulty in other areas in the future. During periods of low oil and/or natural gas prices, existing reserves may no longer be economic, and it will become more difficult to raise the capital necessary to finance expansion activities. If we are unable to replace our current and future production, our reserves will decrease, and our business, financial condition, results of operations and cash flows would be adversely affected.

Our Oil and Natural Gas Reserves Are Estimated and May Not Reflect the Actual Volumes of Oil and Natural Gas We Will Recover, and Significant Inaccuracies in These Reserves Estimates or Underlying Assumptions Will Materially Affect the Quantities and Present Value of Our Reserves.

The process of estimating accumulations of oil and natural gas is complex and inexact, due to numerous inherent uncertainties. This process relies on interpretations of available geological, geophysical, engineering and production data. The extent, quality and reliability of this technical data can vary. This process also requires certain economic assumptions related to, among other things, oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The accuracy of a reserves estimate is a function of:

- the quality and quantity of available data;
- the interpretation of that data;
- the judgment of the persons preparing the estimate; and
- the accuracy of the assumptions used.

The accuracy of any estimates of proved oil and natural gas reserves generally increases with the length of production history. Due to the limited production history of many of our properties, the estimates of future production associated with these properties may be subject to greater variance to actual production than would be the case with properties having a longer production history. As our wells produce over time and more data becomes available, the estimated proved reserves will be redetermined on at least an annual basis and may be adjusted to reflect new information based upon our actual production history, results of exploration and development, prevailing oil and natural gas prices and other factors.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas most likely will vary from our estimates. It is possible that future production declines in our wells may be greater than we have estimated. Any significant variance to our estimates could materially affect the quantities and present value of our reserves.

The Calculated Present Value of Future Net Revenues from Our Proved Oil and Natural Gas Reserves Will Not Necessarily Be the Same as the Current Market Value of Our Estimated Oil and Natural Gas Reserves.

It should not be assumed that the present value of future net cash flows included in this Annual Report on Form 10-K is the current market value of our estimated proved oil and natural gas reserves. As required by SEC rules and regulations, the estimated discounted future net cash flows from proved oil and natural gas reserves are based on current costs held constant over time without escalation and on commodity prices using an unweighted arithmetic average of first-day-of-the-month index prices, appropriately adjusted, for the 12-month period immediately preceding the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs used for these estimates and will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- actual costs and timing of development and production expenditures;

- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

In addition, the 10% discount factor that is required to be used to calculate discounted future net revenues for reporting purposes under U.S. generally accepted accounting principles, or GAAP, is not necessarily the most appropriate discount factor

37

based on the cost of capital in effect from time to time and risks associated with our business and the oil and natural gas industry in general.

Approximately 63% of Our Total Proved Reserves at December 31, 2015 Consisted of Undeveloped and Developed Non-Producing Reserves, and Those Reserves May Not Ultimately Be Developed or Produced.

At December 31, 2015, approximately 60% of our total proved reserves were undeveloped and approximately 3% were developed non-producing. Our undeveloped and/or developed non-producing reserves may never be developed or produced or such reserves may not be developed or produced within the time periods we have projected or at the costs we have estimated. Delays in the development of our reserves or increases in costs to drill and develop such reserves would reduce the present value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves, resulting in some projects becoming uneconomical and reducing our total proved reserves. In addition, delays in the development of reserves or declines in the oil and/or natural gas prices used to estimate proved reserves in the future could cause us to have to reclassify a portion of our proved reserves as unproved reserves. Any reduction in our proved reserves caused by the reclassification of undeveloped or developed non-producing reserves could materially affect our business, financial condition, results of operations and cash flows.

Our Identified Drilling Locations Are Scheduled over Several Years, Making Them Susceptible to Uncertainties That Could Materially Alter the Occurrence or Timing of Their Drilling.

Our management team has identified and scheduled drilling locations in our operating areas over a multi-year period. Our ability to drill and develop these locations depends on a number of factors, including oil and natural gas prices, assessment of risks, costs, drilling results, the availability of equipment and capital, approval by regulators, lease terms and seasonal conditions. The final determination on whether to drill any of these locations will be dependent upon the factors described elsewhere in this Annual Report on Form 10-K as well as, to some degree, the results of our drilling activities with respect to our established drilling locations. Because of these uncertainties, we do not know if the drilling locations we have identified will be drilled within our expected timeframe, or at all, or if we will be able to economically produce hydrocarbons from these or any other potential drilling locations. Our actual drilling activities may be materially different from our current expectations, which could adversely affect our business, financial condition, results of operations and cash flows.

Certain of Our Unproved and Unevaluated Acreage Is Subject to Leases That Will Expire over the Next Several Years Unless Production Is Established on Units Containing the Acreage.

At December 31, 2015, we had leasehold interests in approximately 46,500 net acres across all of our areas of interest that are not currently held by production and are subject to leases with primary or renewed terms that expire prior to December 31, 2017. Unless we establish production, generally in paying quantities, on units containing these leases during their terms or we renew such leases, these leases will expire. 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. In addition, on certain portions of our acreage, third party leases may have been taken and could become immediately effective if our leases expire. If our leases expire or we are unable to renew such leases, we will lose our right to develop the related properties. As such, our actual drilling activities may materially differ from our current expectations, which could adversely affect our business, financial condition, results of operations and cash flows.

The 2-D and 3-D Seismic Data and Other Advanced Technologies We Use Cannot Eliminate Exploration Risk, Which Could Limit Our Ability to Replace and Grow Our Reserves and Materially and Adversely Affect Our Results of Operations and Cash Flows.

We employ visualization and 2-D and 3-D seismic images to assist us in exploration and development activities where applicable. These techniques only assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not allow the interpreter to know conclusively if hydrocarbons are present or economically producible. We could incur losses by drilling unproductive wells based on these technologies. Furthermore, seismic and geological data can be expensive to license or obtain and we may not be able to license or obtain such data at an acceptable cost. Poor results from our exploration activities could limit our ability to replace and grow reserves and adversely affect our business, financial condition, results of operations and cash flows.

Competition in the Oil and Natural Gas Industry Is Intense, Making It More Difficult for Us to Acquire Properties, Market Oil and Natural Gas and Secure Trained Personnel.

Competition is intense in virtually all facets of our business. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid

Table of Contents

for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased in recent years due to competition and may increase substantially in the future. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Our Competitors May Use Superior Technology and Data Resources That We May Be Unable to Afford or That Would Require a Costly Investment by Us in Order to Compete with Them More Effectively.

Our industry is subject to rapid and significant advancements in technology, including the introduction of new products, equipment and services using new technologies and databases. As our competitors use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement new technologies at a substantial cost. In addition, many of our competitors will have greater financial, technical and personnel resources that allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We cannot be certain that we will be able to implement technologies on a timely basis or at a cost that is acceptable to us. One or more of the technologies that we will use or that we may implement in the future may become obsolete, and we may be adversely affected.

Strategic Relationships upon Which We May Rely Are Subject to Change, Which May Diminish Our Ability to Conduct Our Operations.

Our ability to explore, develop and produce oil and natural gas resources successfully and acquire oil and natural gas interests and acreage depends on our developing and maintaining close working relationships with industry participants and on our ability to select and evaluate suitable acquisition opportunities in a highly competitive environment. These relationships are subject to change and, if they do, our ability to grow may be impaired.

To develop our business, we will endeavor to use the business relationships of our management, board and special board advisors to enter into strategic relationships, which may take the form of contractual arrangements with other oil and natural gas companies, including those that supply equipment and other resources that we expect to use in our business, as well as certain financial institutions. We may not be able to establish these strategic relationships, or if established, we may not be able to maintain them. In addition, the dynamics of our relationships with strategic partners may require us to incur expenses or undertake activities we would not otherwise be inclined to incur in order to fulfill our obligations to these partners or maintain our relationships. If our strategic relationships are not established or maintained, our business prospects may be limited, which could diminish our ability to conduct our operations.

The Marketability of Our Production Is Dependent upon Oil and Natural Gas Gathering, Processing and Transportation Facilities Owned and Operated by Third Parties, and the Unavailability of Satisfactory Oil and Natural Gas Gathering, Processing and Transportation Arrangements Could Have a Material Adverse Effect on Our Revenue.

The unavailability of satisfactory oil, natural gas and natural gas liquids gathering, processing and transportation arrangements may hinder our access to oil, natural gas and natural gas liquids markets or delay production from our wells. The availability of a ready market for our oil, natural gas and natural gas liquids production depends on a number of factors, including the demand for, and supply of, oil, natural gas and natural gas liquids and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines, processing facilities and oil and condensate trucking operations owned and operated by third parties. Our failure to obtain these services on acceptable terms could materially harm our business. In addition, certain of these gathering systems, pipelines and processing facilities, particularly in the Delaware Basin, may be outdated or in need of repair and subject to higher rates of line loss, failure and breakdown.

We may be required to shut in wells for lack of a market or because of inadequate or unavailable pipelines, gathering systems or trucking capacity. If that were to occur, we would be unable to realize revenue from those wells until production arrangements were made to deliver our production to market. Furthermore, if we were required to shut in wells we might also be obligated to pay shut-in royalties to certain mineral interest owners in order to maintain our leases. In addition, if we are unable to market our production we may be required to flare natural gas occasionally, which would decrease the volumes sold from our wells.

The disruption of third party facilities due to maintenance, weather or other factors could negatively impact our ability to market and deliver our oil, natural gas and natural gas liquids. The third parties control when or if such facilities are restored and what prices will be charged. In the past, we have experienced pipeline and natural gas processing interruptions and capacity and infrastructure constraints associated with natural gas production, which has, among other things, required us to flare natural gas occasionally. While we have entered into a firm five-year natural gas processing and transportation agreement and a 15-year fixed-fee natural gas gathering and processing agreement covering the anticipated natural gas production from a significant portion of our Eagle Ford shale acreage in South Texas and our Delaware Basin acreage in West Texas, respectively, no assurance can be given that these agreements will alleviate these issues completely, and we may be required to pay deficiency payments under such agreements if we do not meet the thermal quantity transportation or processing commitments, as applicable. We may experience similar interruptions and processing capacity constraints as we continue to explore and develop our Wolfcamp, Bone Spring and other liquids-rich plays in the Delaware Basin in 2016. If we were required to shut in our production for long periods of time due to pipeline interruptions or lack of processing facilities or capacity of these facilities, it could have a material adverse effect on our business, financial condition, results of operations and cash flows.

Financial Difficulties Encountered by Our Oil and Natural Gas Purchasers, Third Party Operators or Other Third Parties Could Decrease Our Cash Flows from Operations and Adversely Affect the Exploration and Development of Our Prospects and Assets.

We derive most of our revenues from the sale of our oil, natural gas and natural gas liquids to unaffiliated third party purchasers, independent marketing companies and midstream companies. We are also subject to credit risk due to the concentration of our oil and natural gas receivables with several significant customers. We cannot predict the extent to which counterparties' businesses would be impacted if oil and natural gas prices decline further, such prices remain depressed for a sustained period of time or other conditions in our industry were to deteriorate. Any delays in payments from our purchasers caused by financial problems encountered by them will have an immediate negative effect on our results of operations and cash flows.

Liquidity and cash flow problems encountered by our working interest co-owners or the third party operators of our non-operated properties may prevent or delay the drilling of a well or the development of a project. Our working interest co-owners may be unwilling or unable to pay their share of the costs of projects as they become due. In the case of a farmout party, we would have to find a new farmout party or obtain alternative funding in order to complete the exploration and development of the prospects subject to a farmout agreement. In the case of a working interest owner, we could be required to pay the working interest owner's share of the project costs. If we are not able to obtain the capital necessary to fund either of these contingencies or find a new farmout party, our results of operations and cash flows could be negatively affected.

Gathering, Processing 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, processing and transportation services, and, to a lesser extent, affiliate companies providing, or developing capacity to provide, such 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 parties may incur substantial costs in order to comply with existing laws and regulations. If existing laws and regulations governing such 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 parties on whom we rely could have a material adverse effect on our business, financial condition, results of operations and cash flows. See "Business — Regulation."

We Have Limited Control over Activities on Properties We Do Not Operate.

We are not the operator on some of our properties, particularly in the Haynesville shale. As a result of our sale of certain assets to Chesapeake in 2008, we do not operate one of our most significant natural gas assets in the Haynesville shale. We also have other non-operated acreage positions in Northwest Louisiana, South Texas, Southeast New Mexico and West Texas. Because we are not the operator for these properties, our ability to exercise influence over the operations of these properties or their associated costs is limited. Our dependence on the operators and other working interest owners of these projects and our limited ability to influence operations and associated costs, or control the risks, could materially and adversely affect the drilling results, reserves and future cash flows from these properties. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors, including:

- timing and amount of capital expenditures;
- the operator's expertise and financial resources;

- the rate of production of reserves, if any;
- approval of other participants in drilling wells; and
- selection and implementation or execution of technology.

In areas where we do not have the right to propose the drilling of wells, we may have limited influence on when, how and at what pace our properties in those areas are developed. Further, the operators of those properties may experience financial problems in the future or may sell their rights to another operator not of our choosing, both of which could limit our ability to develop and monetize the underlying oil or natural gas reserves. In addition, the operators of these properties may elect to curtail the oil or natural gas production or to shut in the wells on these properties during periods of low oil or natural gas prices, and we may receive less than anticipated or no production and associated revenues from these properties until the operator elects to return them to production.

A Component of Our Growth May Come through Acquisitions, and Our Failure to Identify or Complete Future Acquisitions Successfully Could Reduce Our Earnings and Hamper Our Growth.

We may be unable to identify properties for acquisition or to make acquisitions on terms that we consider economically acceptable. There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. The completion and pursuit of acquisitions may be dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. Our ability to grow through acquisitions will require us to continue to invest in operations and financial and management information systems and to attract, retain, motivate and effectively manage our employees.

In addition, we may be unable to successfully integrate any potential acquisitions into our existing operations. The inability to manage the integration of acquisitions, including the HEYCO Merger, effectively could reduce our focus on subsequent acquisitions and current operations, and could negatively impact our results of operations and growth potential. Members of our senior management team may be required to devote considerable amounts of time to the integration process, which will decrease the time they will have to manage our business.

Furthermore, our decision to acquire properties that are substantially different in operating or geologic characteristics or geographic locations from areas with which our staff is familiar may impact our productivity in such areas. Our financial condition, results of operations and cash flows may fluctuate significantly from period to period as a result of the completion of significant acquisitions during particular periods. If we are not successful in identifying or acquiring any material property interests, our earnings could be reduced and our growth could be restricted.

We may engage in bidding and negotiation to complete successful acquisitions. We may be required to alter or increase substantially our capitalization to finance these acquisitions through the use of cash on hand, the issuance of debt or equity securities, the sale of production payments, the sale of non-strategic assets, the borrowing of funds or otherwise. Our Credit Agreement and the indenture governing our outstanding senior notes include covenants limiting our ability to incur additional debt. If we were to proceed with one or more acquisitions involving the issuance of our common stock, our shareholders would suffer dilution of their interests.

We May Purchase Oil and Natural Gas Properties with Liabilities or Risks That We Did Not Know About or That We Did Not Assess Correctly, and, as a Result, We Could Be Subject to Liabilities That Could Adversely Affect Our Results of Operations.

Before acquiring oil and natural gas properties, we estimate the reserves, future oil and natural gas prices, operating costs, potential environmental liabilities and other factors relating to the properties. However, our review involves many assumptions and estimates, and their accuracy is inherently uncertain. As a result, we may not discover all existing or potential problems associated with the properties we buy. We may not become sufficiently familiar with the properties to assess fully their deficiencies and capabilities. We do not generally perform inspections on every well or property, and we may not be able to observe mechanical and environmental problems even when we conduct an inspection. The seller may not be willing or financially able to give us contractual protection against any identified problems, and we may decide to assume environmental and other liabilities in connection with properties we acquire. If we acquire properties with risks or liabilities we did not know about or that we did not assess correctly, our financial condition, results of operations and cash flows could be adversely affected as we settle claims and incur cleanup costs related to these liabilities.

We May Incur Losses or Costs as a Result of Title Deficiencies in the Properties in Which We Invest.

If an examination of the title history of a property that we have purchased reveals an oil and natural gas lease has been purchased in error from a person who is not the owner of the mineral interest desired or other title deficiencies, our interest would be worth less than what we paid or may be worthless. In such an instance, all or part of the amount paid for such oil and natural gas lease as well as all or part of any royalties paid pursuant to the terms of the lease prior to the discovery of the title defect would be lost.

It is not our practice in acquiring oil and natural gas leases, or undivided interests in oil and natural gas leases, to undergo the expense of retaining lawyers to examine the title to the mineral interest to be placed under lease or already placed under lease in all acquisitions. Rather, in certain acquisitions we rely upon the judgment of oil and natural gas lease brokers and/or landmen who perform the field work by examining records in the appropriate governmental office before attempting to acquire a lease on a specific mineral interest.

Prior to the drilling of an oil and natural gas well, however, it is standard industry practice for the operator of the well to obtain a preliminary title review of the spacing unit within which the proposed well is to be drilled to ensure there are no obvious deficiencies in title to the well. Frequently, as a result of such examinations, certain curative work must be done to correct deficiencies in the marketability of the title, and such title review and curative work entails expense, which may be significant and difficult to accurately predict. Our failure to cure any title defects may adversely impact our ability to increase production and reserves. In the future, we may suffer a monetary loss from title defects or title failure. Additionally, unproved and unevaluated acreage has greater risk of title defects than developed acreage. If there are any title defects or defects in assignment of leasehold rights in properties in which we hold an interest, we will suffer a financial loss which could adversely affect our financial condition, results of operations and cash flows.

We May Be Required to Write Down the Carrying Value of Our Proved Properties under Accounting Rules and These Write-Downs Could Adversely Affect Our Financial Condition.

There is a risk that we will be required to write down the carrying value of our oil and natural gas properties when oil or natural gas prices are low or are declining, as they have been since the second half of 2014. In addition, non-cash write-downs may occur if we have:

- downward adjustments to our estimated proved reserves;
- increases in our estimates of development costs; or
- deterioration in our exploration and development results.

We periodically review the carrying value of our oil and natural gas properties under full-cost accounting rules. Under these rules, the net capitalized costs of oil and natural gas properties less related deferred income taxes may not exceed a cost center ceiling that is based on the present value, based on constant prices and costs projected forward from a single point in time, of estimated future after-tax net cash flows from proved reserves, discounted at 10%. If the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceed the cost center ceiling, we must charge the amount of this excess to operations in the period in which the excess occurs. We may not reverse write-downs even if prices increase in subsequent periods.

Although uncertain future prices impact the ability to predict future full-cost ceiling impairments, we do anticipate recognizing full-cost ceiling impairments in 2016. This conclusion is based on the historic prices for 2015 and the first two months of 2016 as well as the short-term pricing outlook. For the year ended December 31, 2015, our net capitalized costs less related deferred income taxes exceeded the full-cost ceiling. As a result, we recorded an impairment charge of $801.2 million, exclusive of tax effect, to our net capitalized costs. For further discussion of the full-cost ceiling impairment at December 31, 2015, see “Management’s Discussion and Analysis of Financial Condition and Results of Operations—Results of Operations—Expenses.” A write-down does not affect net cash flows from operating activities, liquidity or capital resources, but it does reduce the book value of our net tangible assets, retained earnings and shareholders’ equity and could lower the value of our common stock.

Hedging Transactions, or the Lack Thereof, May Limit Our Potential Gains and Could Result in Financial Losses.

To manage our exposure to price risk, we, from time to time, enter into hedging arrangements, using primarily “costless collars” or “swaps” with respect to a portion of our future production. Costless collars provide us with downside price protection through the purchase of a put option which is financed through the sale of a call option. Because the call option proceeds are used to offset the cost of the put option, these arrangements are initially “costless” to us. In the case of a costless collar, the put option and the call option have different fixed price components. In a swap contract, a floating price is exchanged for a fixed price over the specified period, providing downside price protection. The goal of these and other hedges is to lock in a range of prices in the case of collars or a fixed price in the case of swaps so as to mitigate price volatility and increase the predictability of cash flows. These transactions limit our potential gains if oil, natural gas or natural gas liquids prices rise above the maximum price established by the call option and may offer protection if prices fall below the minimum price established by the put option only to the extent of the volumes then hedged.

In addition, hedging transactions may expose us to the risk of financial loss in certain other circumstances, including instances in which our production is less than expected or the counterparties to our put and call option or swap contracts fail to perform under the contracts. Disruptions in the financial markets could lead to sudden changes in a counterparty’s liquidity, which could impair its ability to perform under the terms of the contracts. We are unable to predict sudden changes in a counterparty’s creditworthiness or ability to perform under contracts with us. Even if we do accurately predict sudden changes, our ability to mitigate that risk may be limited depending upon market conditions.

Furthermore, there may be times when we have not hedged our production when, in retrospect, it would have been advisable to do so. Decisions as to whether, at what price and what production volumes to hedge are difficult and depend on market conditions and our forecast of future production and oil, natural gas and natural gas liquids prices, and we may not always employ the optimal hedging strategy. We may employ hedging strategies in the future that differ from those that we have used in the past, and neither the continued application of our current strategies nor our use of different hedging strategies may be successful. As of February 25, 2016, we had 44% and 44% of our estimated remaining 2016 oil and natural gas

Table of Contents

production, respectively, hedged. We currently have no hedges in place for oil or natural gas liquids beyond 2016; however, we have a portion of our anticipated natural gas volumes hedged in 2017.

An Increase in the Differential between the NYMEX or Other Benchmark Prices of Oil and Natural Gas and the Wellhead Price We Receive for Our Production Could Adversely Affect Our Business, Financial Condition, Results of Operations and Cash Flows.

The prices that we receive for our oil and natural gas production sometimes reflect a discount to the relevant benchmark prices, such as NYMEX, that are used for calculating hedge positions. The difference between the benchmark prices and the prices we receive is called a differential. Increases in the differential between the benchmark prices for oil and natural gas and the wellhead prices we receive could adversely affect our business, financial condition, results of operations and cash flows. We do not have, and may not have in the future, any derivative contracts covering the amount of the basis differentials we experience with respect to our production. As such, we will be exposed to any increase in such differentials.

We Are Subject to Government Regulation and Liability, Including Complex Environmental Laws, Which Could Require Significant Expenditures.

The exploration, development, production, gathering, processing, transportation and sale of oil and natural gas in the United States are subject to many federal, state and local laws, rules and regulations, including complex environmental laws and regulations. Matters subject to regulation include discharge permits, drilling bonds, reports concerning operations, the spacing of wells, unitization and pooling of properties, taxation and environmental matters and health and safety criteria addressing worker protection. Under these laws and regulations, we may be required to make large expenditures that could materially adversely affect our financial condition, results of operations and cash flows. In addition to expenditures required in order for us to comply with such laws and regulations, these expenditures could also include payments for:

- personal injuries;
- property damage;
- containment and clean-up of oil and other spills;
- management and disposal of hazardous materials;
- remediation, clean-up costs and natural resource damages; and
- other environmental damages.

We do not believe that full insurance coverage for all potential damages is available at a reasonable cost. Failure to comply with these laws and regulations also may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties, injunctive relief and/or the imposition of investigatory or other remedial obligations. Laws, rules and regulations protecting the environment have changed frequently and the changes often include increasingly stringent requirements. These laws, rules and regulations may impose liability on us for environmental damage and disposal of hazardous materials even if we were not negligent or at fault. We may also be found to be liable for the conduct of others or for acts that complied with applicable laws, rules or regulations at the time we performed those acts. These laws, rules and regulations are interpreted and enforced by numerous federal and state agencies. In addition, private parties, including the owners of properties upon which our wells are drilled or the owners of properties adjacent to or in close proximity to those properties, may also pursue legal actions against us based on alleged non-compliance with certain of these laws, rules and regulations.

Part of the regulatory environment in which we operate includes, in some cases, federal requirements for obtaining environmental assessments, environmental impact statements and/or plans of development before commencing exploration and production activities. Oil and natural gas operations in certain of our operating areas can be adversely affected by seasonal or permanent restrictions on drilling activities designed to protect various wildlife, such as the lesser prairie-chicken and sand dune lizard in the Delaware Basin. The designation of previously unprotected species as threatened or endangered species could prohibit drilling in certain of our operating areas, cause us to incur increased costs arising from species protection measures or result in limitations on our exploration and production activities, each of which could have an adverse impact on our ability to develop and produce our reserves.

We Are Subject to Federal, State and Local Taxes, and May Become Subject to New Taxes or Have Eliminated or Reduced Certain Federal Income Tax Deductions Currently Available with Respect to Oil and Natural Gas Exploration and Production Activities as a Result of Future Legislation, Which Could Adversely Affect Our Business, Financial Condition, Results of Operations and Cash Flows.

The federal, state and local governments in the areas in which we operate impose taxes on the oil and natural gas products we sell and, for many of our wells, sales and use taxes on significant portions of our drilling and operating costs. Many states have raised state taxes on energy sources or state taxes associated with the extraction of hydrocarbons, and

Table of Contents

additional increases may occur. In addition, there has been a significant amount of discussion by legislators and presidential administrations concerning a variety of energy tax proposals.

Periodically, legislation is introduced to eliminate certain key U.S. federal income tax preferences currently available to oil and natural gas exploration and production companies. Such changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for certain oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain U.S. production or manufacturing activities and (iv) the increase in the amortization period for geological and geophysical costs paid or incurred in connection with the exploration for, or development of, oil or natural gas within the United States. President Obama has proposed sweeping changes in federal laws on the income taxation of small oil and natural gas exploration and production companies like ours. President Obama has proposed to eliminate allowing small oil and natural gas companies to deduct intangible drilling costs as incurred and percentage depletion. The passage of any legislation as a result of the budget proposals or any other similar change in U.S. federal income tax law could affect certain tax deductions that are currently available with respect to oil and natural gas exploration and production activities and could negatively impact our financial condition, results of operations and cash flows.

Federal and State Legislation and Regulatory Initiatives Relating to Hydraulic Fracturing Could Result in Increased Costs and Additional Operating Restrictions or Delays.

Hydraulic fracturing involves the injection of water, sand or other propping agents and chemicals under pressure into rock formations to stimulate oil and natural gas production. We routinely use hydraulic fracturing to complete wells in order to produce oil, natural gas and natural gas liquids from formations such as the Wolfcamp and Bone Spring plays, the Eagle Ford shale and the Haynesville shale, where we focus our operations. The EPA released the draft results of its comprehensive research study on the potential adverse impacts that hydraulic fracturing may have on drinking water resources in June 2015. The EPA did not find evidence of widespread, systemic impacts on drinking water resources in the United States, although it did note a lack of data in many areas. The results of the EPA's study could spur action towards federal legislation and regulation of hydraulic fracturing or similar production operations. In past sessions, Congress has considered, but did not pass, legislation to amend the Safe Drinking Water Act, or SDWA, to remove the SDWA's exemption granted to most hydraulic fracturing operations (other than operations using fluids containing diesel) and to require reporting and disclosure of chemicals used by oil and natural gas companies in the hydraulic fracturing process. The EPA has issued SDWA permitting guidance for hydraulic fracturing operations involving the use of diesel fuel in fracturing fluids in those states where the EPA is the permitting authority. Additionally, the EPA has issued an Advance Notice of Proposed Rulemaking under the Toxic Substances Control Act to develop regulations governing the disclosure of hydraulic fracturing chemicals. Also at the federal level, the BLM issued final rules to regulate hydraulic fracturing on federal lands in March 2015, although these rules have been stayed by a federal court in Wyoming.

In addition, a number of states and local regulatory authorities are considering or have implemented more stringent regulatory requirements applicable to hydraulic fracturing, including bans/moratoria on drilling that effectively prohibit further production of oil and natural gas through the use of hydraulic fracturing or similar operations. For example, in December 2014, New York announced a moratorium on high volume fracturing activities combined with horizontal drilling following the issuance of a study regarding the safety of hydraulic fracturing. Certain communities in Colorado have also enacted bans on hydraulic fracturing. These actions are the subject of legal challenges. Texas, New Mexico and Wyoming have adopted regulations that require the disclosure of information regarding the substances used in the hydraulic fracturing process. These restrictions and regulations could increase our costs of compliance and doing business.

The adoption of new laws or regulations imposing reporting or operational obligations on, or otherwise limiting or prohibiting, the hydraulic fracturing process could make it more difficult to complete oil and natural gas wells in unconventional plays. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, hydraulic fracturing activities could become subject to additional permitting requirements, and also to attendant permitting delays and potential increases in cost, which could adversely affect our business and results of operations.

Legislation or Regulations Restricting Emissions of Greenhouse Gases Could Result in Increased Operating Costs and Reduced Demand for the Oil, Natural Gas and Natural Gas Liquids We Produce while the Physical Effects of Climate Change Could Disrupt Our Production and Cause Us to Incur Significant Costs in Preparing for or Responding to Those Effects.

The EPA has published its final findings that emissions of carbon dioxide, methane and other greenhouse gases present an endangerment to public health and welfare because emissions of such gases are, according to the EPA, contributing to the warming of the earth's atmosphere and other climatic changes. Accordingly, the EPA has adopted rules under the CAA for the permitting of greenhouse gas emissions from stationary sources under the Prevention of Significant Deterioration ("PSD") and Title V permitting programs. The EPA has adopted a multi-tiered approach to this permitting, with the largest sources first subject to permitting. In addition, monitoring of greenhouse gas emissions from petroleum and natural gas systems commenced on January 1, 2011, with the first annual reports required to be filed in 2012. There were attempts at comprehensive federal legislation establishing a cap and trade program, but that legislation did not pass. Further, various states have considered or adopted legislation that seeks to control or reduce emissions of greenhouse gases from a wide range of sources. Finally, ongoing international discussions are exploring options to succeed the Kyoto Protocol, most recently at the United Nations Conference on climate change in Paris in November and December 2015. These discussions resulted in a non-binding international agreement to make certain global emissions reductions at a national level, which in turn could further drive regulation in the United States. Any future international agreements, federal or state laws or implementing regulations that may be adopted to address greenhouse gas emissions could, and in all likelihood would, require us to incur increased operating costs adversely affecting our profits and could adversely affect demand for the oil and natural gas we produce, depressing the prices we receive for oil and natural gas.

In an interpretative guidance on climate change disclosures, the SEC indicated that climate change could have an effect on the severity of weather (including hurricanes and floods), sea levels, the arability of farmland and water availability and quality. If such effects were to occur, there is the potential for our exploration and production operations to be adversely affected. Potential adverse effects could include damages to our facilities from powerful winds or rising waters in low-lying areas, disruption of our production, less efficient or non-routine operating practices necessitated by climate effects or increased costs for insurance coverages in the aftermath of such effects. Significant physical effects of climate change could also have an indirect effect on our financing and operations by disrupting the transportation or process-related services provided by midstream companies, service companies or suppliers with whom we have a business relationship. We may not be able to recover through insurance some or any of the damages, losses or costs that may result from potential physical effects of climate change. In addition, our hydraulic fracturing operations require large amounts of water. See "—If We Are Unable to Acquire Adequate Supplies of Water for Our Drilling and Hydraulic Fracturing Operations or Are Unable to Dispose of the Water We Use at a Reasonable Cost and Pursuant to Applicable Environmental Rules, Our Ability to Produce Oil and Natural Gas Commercially and in Commercial Quantities Could Be Impaired." Should climate change or other drought conditions occur, our ability to obtain water of a sufficient quality and quantity could be impacted and in turn, our ability to perform hydraulic fracturing operations could be restricted or made more costly.

New Regulations on All Emissions from Our Operations Could Cause Us to Incur Significant Costs.

On April 17, 2012, the EPA issued final rules to subject oil and natural gas operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAPS, programs under the CAA, and to impose new and amended requirements under both programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells. Since January 1, 2015, operators must capture the natural gas and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to new hydraulically fractured wells and also existing wells that are refractured. The finalized regulations also established specific requirements for emissions from compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment. These rules have required changes to our operations, including the installation of new equipment to control emissions. Further, in August 2015, the EPA issued proposed NSPS governing methane emissions from the oil and natural gas industry as well as proposed source determination standards for determining when oil and gas sources should be aggregated for CAA permitting and compliance purposes. The proposed NSPS for methane would extend the 2012 NSPS to remaining equipment and processes not currently regulated under the existing standards, including: completions of hydraulically fractured oil wells, equipment leaks, pneumatic pumps and natural gas compressors. We continue to evaluate the effect these rules would have on our business and operations. On January 22, 2016, the Department of the Interior proposed rules relating to the venting, flaring and leaking of natural gas by oil and natural gas producers who operate on federal and Indian lands. The proposed rules would, among other things, limit routine flaring of natural gas, require the payment of royalties on avoidable gas losses and require plans or programs relating to gas capture and leak detection and repair. The proposed rules are still in the period for public comment. These rules could increase our operating costs and have a material adverse effect on our business and operations.

A Change in the Jurisdictional Characterization of Some of Our Assets by FERC or a Change in Policy by It May Result in Increased Regulation of Our Assets, Which May Cause Our Revenues to Decline and Operating Expenses to Increase.

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline’s status as a gatherer not subject to regulation as a natural gas company. However, the distinction between FERC-regulated transmission services and federally unregulated gathering services is the subject of ongoing litigation, so the classification and regulation of our gathering facilities are subject to change based on future determinations by FERC, the courts or Congress. A change in the jurisdictional characterization by FERC, the courts or Congress or a change in policy by FERC or Congress may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Table of Contents

Should We Fail to Comply with All Applicable FERC-Administered Statutes, Rules, Regulations and Orders, We Could Be Subject to Substantial Penalties and Fines.

Under the Energy Policy Act, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1.0 million per day for each violation and disgorgement of profits associated with any violation. The nature of our gathering facilities is such that we have not yet been regulated by FERC as a natural gas company subject to the provisions of the NGA. It is possible, however, that laws, rules and regulations pertaining to those and other matters may be considered or adopted by FERC or Congress from time to time. Failure to comply with those laws, rules and regulations in the future could subject us to civil penalty liability.

The Derivatives Legislation Adopted by Congress Could Have an Adverse Impact on Our Ability to Hedge Risks Associated with Our Business.

On July 21, 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, which is intended to modernize and protect the integrity of the U.S. financial system. The Dodd-Frank Act, among other things, establishes federal oversight and regulation of certain derivative products, including commodity hedges of the type we use. The Dodd-Frank Act requires the Commodity Futures Trading Commission, or CFTC, and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented, and it is not possible at this time to predict when this will be accomplished.

In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position limits rule was vacated by the United States District Court for the District of Columbia in September 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time. The Dodd-Frank Act could also result in additional regulatory requirements on our derivative arrangements, which could include new margin, reporting and clearing requirements. In addition, this legislation could have a substantial impact on our counterparties and may increase the cost of our derivative arrangements in the future.

If these types of commodity hedges become unavailable or uneconomic, our commodity price risk could increase, which would increase the volatility of revenues and may decrease the amount of credit available to us. Any limitations or changes in our use of derivative arrangements could also materially affect our cash flows, which could adversely affect our ability to make capital expenditures.

Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and implementing regulations is to lower commodity prices.

Any of these consequences could have a material adverse effect on our business, financial condition and results of operations.

We May Have Difficulty Managing Growth in Our Business, Which Could Have a Material Adverse Effect on Our Business, Financial Condition, Results of Operations and Cash Flows and Our Ability to Execute Our Business Plan in a Timely Fashion.

Because of our size, growth in accordance with our business plans, if achieved, will place a significant strain on our financial, technical, operational and management resources. As and when we expand our activities, including any increase in oil exploration, development and production, and any increase in the number of projects we are evaluating or in which we participate, there will be additional demands on our financial, technical and management resources. The failure to continue to upgrade our technical, administrative, operating and financial control systems or the occurrence of unexpected expansion difficulties, including the inability to recruit and retain experienced managers, geoscientists, petroleum engineers, landmen, attorneys and financial and accounting professionals, could have a material adverse effect on our business, financial condition, results of operations and cash flows and our ability to execute our business plan in a timely fashion.

Our Success Depends, to a Large Extent, on Our Ability to Retain Our Key Personnel, Including Our Chairman and Chief Executive Officer, Management and Technical Team, the Members of Our Board of Directors and Our Special Board Advisors, and the Loss of Any Key Personnel, Board Member or Special Board Advisor Could Disrupt Our Business Operations.

Investors in our common stock must rely upon the ability, expertise, judgment and discretion of our management and the success of our technical team in identifying, evaluating and developing prospects and reserves. Our performance and success are dependent to a large extent on the efforts and continued employment of our management and technical personnel, including our Chairman and Chief Executive Officer, Joseph Wm. Foran. We do not believe that they could be quickly replaced with

Table of Contents

personnel of equal experience and capabilities, and their successors may not be as effective. We have entered into employment agreements with Mr. Foran and other key personnel. However, these employment agreements do not ensure that these individuals will remain in our employment. If Mr. Foran or other key personnel resign or become unable to continue in their present roles and if they are not adequately replaced, our business operations could be adversely affected. With the exception of Mr. Foran, we do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

We have an active Board of Directors that meets at least quarterly throughout the year and is closely involved in our business and the determination of our operational strategies. Members of our Board of Directors work closely with management to identify potential prospects, acquisitions and areas for further development. Certain of our directors have been involved with us since our inception and have a deep understanding of our operations and culture. If any of our directors resign or become unable to continue in their present role, it may be difficult to find replacements with the same knowledge and experience and, as a result, our operations may be adversely affected.

In addition, our board consults regularly with our special advisors regarding our business and the evaluation, exploration, engineering and development of our prospects. Due to the knowledge and experience of our special advisors, they play a key role in our multi-disciplined approach to making decisions regarding prospects, acquisitions and development. If any of our special advisors resign or become unable to continue in their present role, our operations may be adversely affected.

A Cyber Incident Could Occur and Result in Information Theft, Data Corruption, Operational Disruption or Financial Loss.

The oil and natural gas industry is dependent on digital technologies to conduct certain exploration, development, production and financial activities. We depend on digital technology to, among other things, estimate oil and natural gas reserves quantities, plan, execute and analyze drilling, completion and production operations and data, process and record financial and operating data and communicate with employees, shareholders, royalty owners and other third-party industry participants.

While we have not experienced any material losses due to cyber attacks, we may suffer such losses in the future. If our systems for protecting against cyber incidents prove to be insufficient, we could be adversely affected by unauthorized access to our proprietary information which could lead to data corruption, communication interruption, exposure of confidential or proprietary information, operational disruptions or financial loss. As cyber threats continue to evolve, we may be required to expend additional resources to continue to modify and enhance our protective systems or to investigate and remediate any vulnerabilities.

Risks Relating to Our Common Stock

The Price of Our Common Stock Has Fluctuated Substantially and May Fluctuate Substantially in the Future.

Our stock price has experienced volatility and could vary significantly as a result of a number of factors. In 2015, our stock price fluctuated between a high of $29.90 and a low of $18.28. In addition, the trading volume of our common stock may continue to fluctuate and cause significant price variations to occur. In the event of a drop in the market price of our common stock, you could lose a substantial part or all of your investment in our common stock. In addition, the stock markets in general have experienced extreme volatility that has often been unrelated to the operating performance of particular companies. These broad market fluctuations may adversely affect the trading price of our common stock.

Factors that could affect our stock price or result in fluctuations in the market price or trading volume of our common stock include:

- our actual or anticipated operating and financial performance and drilling locations, including oil and natural gas reserves estimates;
- quarterly variations in the rate of growth of our financial indicators, such as net income per share, net income and cash flows, or those of companies that are perceived to be similar to us;
- changes in revenue, cash flows or earnings estimates or publication of reports by equity research analysts;
- speculation in the press or investment community;
- announcement or consummation of acquisitions or dispositions by us;

- public reaction to our press releases, announcements and filings with the SEC;
- sales of our common stock by us or shareholders, or the perception that such sales may occur;
- general financial market conditions and oil and natural gas industry market conditions, including fluctuations in the price of oil, natural gas and natural gas liquids;
- the realization of any of the risk factors presented in this Annual Report on Form 10-K;

Table of Contents

- the recruitment or departure of key personnel;
- commencement of or involvement in litigation;
- the success of our exploration and development operations, and the marketing of any oil, natural gas and natural gas liquids we produce;
- changes in market valuations of companies similar to ours; and
- domestic and international economic, legal and regulatory factors unrelated to our performance.

If We Fail to Maintain Effective Internal Control over Financial Reporting in the Future, Our Ability to Accurately Report Our Financial Results Could Be Adversely Affected.

As a public company with listed equity securities, we are required to comply with laws, regulations and requirements, certain corporate governance provisions of the Sarbanes-Oxley Act of 2002, related regulations of the SEC and the requirements of the NYSE. Complying with these statutes, regulations and requirements is difficult and occupies a significant amount of time of our Board of Directors and management and has significantly increased our costs and expenses.

Pursuant to the Sarbanes-Oxley Act, we are required to maintain internal controls over financial reporting. Our efforts to maintain our internal controls may not be successful, and we may be unable to maintain effective controls over our financial processes and reporting in the future and comply with the certification and reporting obligations under Sections 302 and 404 of the Sarbanes-Oxley Act. Our management does not expect that our internal controls and disclosure controls will prevent all possible error or all fraud. Further, our remediation efforts may not enable us to avoid material weaknesses in the future. Any failure to maintain effective controls could result in material misstatements that are not prevented or detected and corrected on a timely basis, which could potentially subject us to sanction or investigation by the SEC, the NYSE or other regulatory authorities. Ineffective internal controls could also cause investors to lose confidence in our reported financial information and adversely affect our business and our stock price.

We Do Not Presently Intend to Pay Any Cash Dividends on or Repurchase Any Shares of Our Common Stock.

We do not presently intend to pay any cash dividends on or repurchase any shares of our common stock. Any payment of future dividends will be at the discretion of our Board of Directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applicable to the payment of dividends and other considerations that our Board of Directors deems relevant. Cash dividend payments in the future may only be made out of legally available funds and, if we experience substantial losses, such funds may not be available. In addition, certain covenants in our Credit Agreement and the indenture governing our outstanding senior notes may limit our ability to pay dividends or repurchase shares of our common stock. Accordingly, you may have to sell some or all of your common stock in order to generate cash flow from your investment, and there is no guarantee that the price of our common stock will exceed the price you paid.

Future Sales of Shares of Our Common Stock by Existing Shareholders and Future Offerings of Our Common Stock by Us Could Depress the Price of Our Common Stock.

The market price of our common stock could decline as a result of sales of a large number of shares of our common stock in the market, including shares of equity or debt securities convertible into common stock, and the perception that these sales could occur may also depress the market price of our common stock. If our existing shareholders sell, or indicate an intent to sell, substantial amounts of our common stock in the public market, the trading price of our common stock could decline significantly. Sales of our common stock may make it more difficult for us to sell equity securities in the future at a time and at a price that we deem appropriate. These sales could also cause our stock price to decrease and make it more difficult for you to sell shares of our common stock.

We may also sell or issue additional shares of common stock or equity or debt securities convertible into common stock in public or private offerings or in connection with acquisitions. We cannot predict the size of future issuances of our common stock or convertible securities or the effect, if any, that future issuances and sales of shares of our common stock or convertible securities would have on the market price of our common stock.

Provisions of Our Certificate of Formation, Bylaws and Texas Law May Have Anti-Takeover Effects That Could Prevent a Change in Control Even if It Might Be Beneficial to Our Shareholders.

Our certificate of formation and bylaws contain certain provisions that may discourage, delay or prevent a merger or acquisition that our shareholders may consider favorable. These provisions include:

- authorization for our Board of Directors to issue preferred stock without shareholder approval;
- a classified Board of Directors so that not all members of our Board of Directors are elected at one time;

- the prohibition of cumulative voting in the election of directors; and
- a limitation on the ability of shareholders to call special meetings to those owning at least 25% of our outstanding shares of common stock.

Provisions of Texas law may also discourage, delay or prevent someone from acquiring or merging with us, which may cause the market price of our common stock to decline. Under Texas law, a shareholder who beneficially owns more than 20% of our voting stock, or an affiliated shareholder, cannot acquire us for a period of three years from the date this person became an affiliated shareholder, unless various conditions are met, such as approval of the transaction by our Board of Directors before this person became an affiliated shareholder or approval of the holders of at least two-thirds of our outstanding voting shares not beneficially owned by the affiliated shareholder.

Our Directors and Executive Officers Own a Significant Percentage of Our Equity, Which Could Give Them Influence in Corporate Transactions and Other Matters, and the Interests of Our Directors and Executive Officers Could Differ from Other Shareholders.

As of February 25, 2016, our directors and executive officers beneficially owned approximately 14% of our outstanding common stock. These shareholders could influence or control to some degree the outcome of matters requiring a shareholder vote, including the election of directors, the adoption of any amendment to our certificate of formation or bylaws and the approval of mergers and other significant corporate transactions. Their influence or control of the Company may have the effect of delaying or preventing a change of control of the Company and may adversely affect the voting and other rights of other shareholders. In addition, due to their ownership interest in our common stock, our directors and executive officers may be able to remain entrenched in their positions.

Our Board of Directors Can Authorize the Issuance of Preferred Stock, Which Could Diminish the Rights of Holders of Our Common Stock and Make a Change of Control of the Company More Difficult Even if It Might Benefit Our Shareholders.

Our Board of Directors is authorized to issue shares of preferred stock in one or more series and to fix the voting powers, preferences and other rights and limitations of the preferred stock. Accordingly, we may issue shares of preferred stock with a preference over our common stock with respect to dividends or distributions on liquidation or dissolution, or that may otherwise adversely affect the voting or other rights of the holders of common stock. Issuances of preferred stock, depending upon the rights, preferences and designations of the preferred stock, may have the effect of delaying, deterring or preventing a change of control of the company, even if that change of control might benefit our shareholders.

Item 1B. Unresolved Staff Comments.

Not applicable.

Item 2. Properties.

See “Business” for descriptions of our properties. We also have various operating leases for rental of office space and office and field equipment. See Note 13 to the consolidated financial statements in this Annual Report on Form 10-K for the future minimum rental payments. Such information is incorporated herein by reference.

Item 3. Legal Proceedings.

We are a defendant in several lawsuits encountered in the ordinary course of our business. While the ultimate outcome and impact to us cannot be predicted with certainty, in the opinion of management, it is remote that these lawsuits will have a material adverse impact on our financial condition, results of operations or cash flows.

Item 4. Mine Safety Disclosures.

Not applicable.

Table of Contents

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities.

General Market Information

Shares of our common stock are traded on the NYSE under the symbol "MTDR." Our shares have been traded on the NYSE since February 2, 2012. Prior to trading on the NYSE, there was no established public trading market for our common stock.

On February 25, 2016, we had 85,801,633 shares of common stock outstanding held by approximately 340 record holders, excluding shareholders for whom shares are held in "nominee" or "street" name.

The following table sets forth the high and low sales prices of our common stock as reported by the NYSE for the periods indicated.

	2015		2014	
	High	Low	High	Low
First Quarter	$25.08	$18.28	$25.84	$17.95
Second Quarter	$29.90	$22.01	$29.36	$23.28
Third Quarter	$26.07	$19.08	$29.94	$23.70
Fourth Quarter	$28.25	$18.87	$26.09	$14.08

On February 25, 2016, the last reported sales price of our common stock on the NYSE was $15.93 per share.

Dividend Policy

We do not anticipate declaring or paying any cash dividends to holders of our common stock in the foreseeable future. We currently intend to retain future earnings to finance the expansion of our business. Our future dividend policy is within the discretion of our Board of Directors and will depend upon various factors, including our results of operations, financial condition, capital requirements and investment opportunities. In addition, certain covenants in our Credit Agreement and the indenture governing our outstanding senior notes may limit our ability to pay dividends on our common stock. During the years ended December 31, 2015 and 2014, we did not pay dividends to holders of our common stock.

Equity Compensation Plan Information

The following table presents the securities authorized for issuance under our equity compensation plans as of December 31, 2015.

Equity Compensation Plan Information

Plan Category	Number of Shares to be Issued Upon Exercise of Outstanding Options, Warrants and Rights	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights	Number of Shares Remaining Available for Future Issuance Under Equity Compensation Plans
Equity compensation plans approved by security holders[1] [2]	2,436,784	$ 15.40	5,066,503
Equity compensation plans not approved by security holders	—	—	—
Total	2,436,784	$ 15.40	5,066,503

(1) Our Board of Directors has determined not to make any additional grants of awards under the Matador Resources Company 2003 Stock and Incentive Plan.

(2) The Amended and Restated 2012 Long-Term Incentive Plan was adopted by our Board of Directors in April 2015 and approved by our shareholders on June 10, 2015. For a description of our Amended and Restated 2012

Long-Term Incentive Plan, see Note 8 to the consolidated financial statements in this Annual Report on Form 10-K.

Table of Contents

Share Performance Graph

The following graph compares the cumulative return on a $100 investment in our common stock from February 2, 2012, the date our common stock began trading on the NYSE, through December 31, 2015, to that of the cumulative return on a $100 investment in the Russell 2000 Index and the Russell 2000 Energy Index for the same period. In calculating the cumulative return, reinvestment of dividends, if any, is assumed.

This graph is not “soliciting material,” is not deemed filed with the SEC and is not to be incorporated by reference in any of our filings under the Securities Act or the Exchange Act, whether made before or after the date hereof and irrespective of any general incorporation language in any such filing. This graph is included in accordance with the SEC’s disclosure rules. This historic stock performance is not indicative of future stock performance.

Comparison of Cumulative Total Return Among
Matador Resources Company, the Russell 2000 Index
and the Russell 2000 Energy Index

Table of Contents

Repurchase of Equity by the Company or Affiliates

During the quarter ended December 31, 2015, the Company re-acquired shares of common stock from certain employees in order to satisfy the employees' tax liability in connection with the vesting of restricted stock.

Period	Total Number of Shares Purchased (1)	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Number of Shares that May Yet Be Purchased under the Plans or Programs
October 1, 2015 to October 31, 2015	674	$27.48	—	—
November 1, 2015 to November 30, 2015	912	26.35	—	—
December 1, 2015 to December 31, 2015	—	—	—	—
Total	1,586	$26.83	—	—

(1) The shares were not re-acquired pursuant to any repurchase plan or program.

Table of Contents

Item 6. Selected Financial Data.

You should read the following selected financial data in conjunction with “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and our consolidated financial statements and related notes thereto included elsewhere in this Annual Report on Form 10-K. The financial information included in this Annual Report on Form 10-K may not be indicative of our future results of operations, financial condition or cash flows.

The following selected financial information is summarized from our results of operations for the five-year period ended December 31, 2015 and selected consolidated balance sheet and cash flow data at December 31, 2015, 2014, 2013, 2012 and 2011 and should be read in conjunction with the consolidated financial statements for the years ended December 31, 2015, 2014 and 2013 included herewith.

	Year Ended December 31,				
	2015	2014	2013	2012	2011
(In thousands, except per share data)					
Statement of operations data:					
Revenues					
Oil and natural gas revenues	$278,340	$367,712	$269,030	$155,998	$67,000
Realized gain (loss) on derivatives	77,094	5,022	(909)	13,960	7,106
Unrealized (loss) gain on derivatives	(39,265)	58,302	(7,232)	(4,802)	5,138
Total revenues	316,169	431,036	260,889	165,156	79,244
Expenses					
Production taxes and marketing	35,535	33,172	20,973	11,672	6,278
Lease operating	58,193	51,353	38,720	28,184	7,244
Depletion, depreciation and amortization	178,847	134,737	98,395	80,454	31,754
Accretion of asset retirement obligations	734	504	348	256	209
Full-cost ceiling impairment	801,166	—	21,229	63,475	35,673
General and administrative	50,105	32,152	20,779	14,543	13,394
Total expenses	1,124,580	251,918	200,444	198,584	94,552
Operating (loss) income	(808,411)	179,118	60,445	(33,428)	(15,308)
Other income (expense):					
Net gain (loss) on asset sales and inventory impairment	908	—	(192)	(485)	(154)
Interest expense	(21,754)	(5,334)	(5,687)	(1,002)	(683)
Interest and other income	2,365	1,345	225	224	315
Total other (expense) income	(18,481)	(3,989)	(5,654)	(1,263)	(522)
Net (loss) income	(679,524)	110,754	45,094	(33,261)	(10,309)
Net (income) loss attributable to non-controlling interest in subsidiaries	(261)	17	—	—	—
Net (loss) income attributable to Matador Resources Company shareholders	$(679,785)	$110,771	$45,094	$(33,261)	$(10,309)
Earnings (loss) per common share					
Basic					
Class A [1]	$(8.34)	$1.58	$0.77	$(0.62)	$(0.25)
Class B [1]	$—	$—	$—	$(0.35)	$0.02
Diluted					
Class A [1]	$(8.34)	$1.56	$0.77	$(0.62)	$(0.25)
Class B [1]	$—	$—	$—	$(0.35)	$0.02
Class B dividend declared, per share [1]	$—	$—	$—	$0.27	$0.27

(1) Our Class B common stock converted into Class A common stock upon the consummation of our initial public offering on February 7, 2012 and the Class A common stock then became the only class of common stock authorized. The term “Class A common stock” refers to shares of our Class A common stock prior to the automatic conversion of our Class B common stock into Class A common stock upon the consummation of our initial public offering.

Table of Contents

	At December 31,				
	2015	2014	2013	2012	2011
(In thousands)					
Balance sheet data:					
Cash and cash equivalents	$16,732	$8,407	$6,287	$2,095	$10,284
Restricted cash	44,357	609	—	—	—
Certificates of deposit	—	—	—	230	1,335
Net property and equipment	1,012,406	1,322,072	845,877	591,090	399,865
Total assets	1,140,861	1,434,490	890,330	632,029	439,469
Current liabilities	136,830	142,036	100,327	96,492	74,576
Long-term liabilities	515,072	425,913	221,079	156,433	93,378
Total Matador Resources Company shareholders' equity	$488,003	$866,408	$568,924	$379,104	$271,515

	Year Ended December 31,				
	2015	2014	2013	2012	2011
(In thousands)					
Other financial data:					
Net cash provided by operating activities	$208,535	$251,481	$179,470	$124,228	$61,868
Net cash used in investing activities	(425,154)	(570,531)	(366,939)	(306,916)	(160,088)
Oil and natural gas properties capital expenditures	(432,715)	(560,849)	(363,192)	(300,689)	(156,431)
Expenditures for other property and equipment	(64,499)	(9,152)	(3,977)	(7,332)	(4,671)
Net cash provided by financing activities	224,944	321,170	191,661	174,499	87,444
Adjusted EBITDA [(1)]	$223,155	$262,943	$191,771	$115,923	$49,911

(1) Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see " – Non-GAAP Financial Measures" below.

Non-GAAP Financial Measures

We define Adjusted EBITDA as earnings before interest expense, income taxes, depletion, depreciation and amortization, accretion of asset retirement obligations, property impairments, unrealized derivative gains and losses, certain other non-cash items and non-cash stock-based compensation expense, and net gain or loss on asset sales and inventory impairment. Adjusted EBITDA is not a measure of net income (loss) or cash flows as determined by GAAP. Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies. Management believes Adjusted EBITDA is necessary because it allows us to evaluate our operating performance and compare the results of operations from period to period without regard to our financing methods or capital structure. We exclude the items listed above from net income (loss) in calculating Adjusted EBITDA, because these amounts can vary substantially from company to company within our industry depending upon accounting methods and book values of assets, capital structures and the method by which certain assets were acquired.

Adjusted EBITDA should not be considered an alternative to, or more meaningful than, net income or cash flows from operating activities as determined in accordance with GAAP or as an indicator of our operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components of understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure. Our Adjusted EBITDA may not be comparable to similarly titled measures of another company because all companies may not calculate Adjusted EBITDA in the same manner. The following table presents our calculation of Adjusted EBITDA and the reconciliation of Adjusted EBITDA to the GAAP financial measures of net income (loss) and net cash provided by operating activities, respectively.

54

Table of Contents

(In thousands)	Year Ended December 31, 2015	2014	2013	2012	2011
Unaudited Adjusted EBITDA Reconciliation to Net (Loss) Income:					
Net (loss) income attributable to Matador Resources Company shareholders	$(679,785)	$110,771	$45,094	$(33,261)	$(10,309)
Interest expense	21,754	5,334	5,687	1,002	683
Total income tax (benefit) provision	(147,368)	64,375	9,697	(1,430)	(5,521)
Depletion, depreciation and amortization	178,847	134,737	98,395	80,454	31,754
Accretion of asset retirement obligations	734	504	348	256	209
Full-cost ceiling impairment	801,166	—	21,229	63,475	35,673
Unrealized loss (gain) on derivatives	39,265	(58,302)	7,232	4,802	(5,138)
Stock-based compensation expense	9,450	5,524	3,897	140	2,406
Net (gain) loss on asset sales and inventory impairment	(908)	—	192	485	154
Adjusted EBITDA	$223,155	$262,943	$191,771	$115,923	$49,911

(In thousands)	Year Ended December 31, 2015	2014	2013	2012	2011
Unaudited Adjusted EBITDA Reconciliation to Net Cash Provided by Operating Activities:					
Net cash provided by operating activities	$208,535	$251,481	$179,470	$124,228	$61,868
Net change in operating assets and liabilities	(8,980)	5,978	6,210	(9,307)	(12,594)
Interest expense, net of non-cash portion	20,902	5,334	5,687	1,002	683
Current income tax provision (benefit)	2,959	133	404	—	(46)
Net (income) loss attributable to non-controlling interest in subsidiaries	(261)	17	—	—	—
Adjusted EBITDA	$223,155	$262,943	$191,771	$115,923	$49,911

Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations.

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes appearing elsewhere in this Annual Report on Form 10-K. The following discussion contains “forward-looking statements” that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions or beliefs about future events may, and often do, vary from actual results and the differences can be material. Some of the key factors which could cause actual results to vary from our expectations include changes in oil or natural gas prices, the timing of planned capital expenditures, availability under our Credit Agreement borrowing base, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, the proximity to and capacity of gathering, processing and transportation facilities, availability and integration of acquisitions, uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below and elsewhere in this Annual Report on Form 10-K, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward-looking events discussed may not occur. See “Cautionary Note Regarding Forward-Looking Statements.”

Overview

We are an independent energy company founded in July 2003 and engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with an emphasis on oil and natural gas shale and other unconventional plays. Our current operations are focused primarily on the oil and liquids-rich portion of the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. We also operate in the Eagle Ford shale play in South Texas and the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas.

2015 Operational Highlights

During the year ended December 31, 2015, we completed and began producing oil and natural gas from 27 gross (23.7 net) operated and 14 gross (1.3 net) non-operated wells in the Delaware Basin. Although we suspended our Eagle Ford drilling and completion operations in the second quarter of 2015, we also completed and began producing oil and natural gas from 17 gross (17.0 net) operated and one gross (0.3 net) non-operated Eagle Ford shale wells. We did not conduct any operated drilling and completion activities on our leasehold properties in Northwest Louisiana and East Texas during 2015, although we did participate in the drilling and completion of 22 gross (1.9 net) non-operated Haynesville shale wells that were turned to sales in 2015.

At January 1, 2015, we were operating five contracted drilling rigs two rigs in the Eagle Ford shale in South Texas and three rigs in the Delaware Basin in Southeast New Mexico and West Texas, but we reduced our operated drilling rigs to two by the end of the first quarter of 2015 with both rigs operating in the Delaware Basin. In late July 2015, we took delivery of a third state-of-the-art, new-build drilling rig in the Delaware Basin specifically customized to our specifications. Overall, we have been very pleased with the initial performance of the wells we have drilled and completed, or participated in as a non-operator, thus far in our six main prospect areas in the Delaware Basin—the Wolf and Jackson Trust prospect areas in Loving County, Texas, the Rustler Breaks and Arrowhead prospect areas in Eddy County, New Mexico and the Ranger and Twin Lakes prospect areas in Lea County, New Mexico. As a result, our Delaware Basin properties have become an increasingly important component of our asset portfolio. Approximately 78% of our 2015 capital expenditures of $482.1 million (excluding capital expenditures associated with the HEYCO Merger) were directed to the delineation and development of our leasehold position in the Delaware Basin, to the development of certain midstream assets to support our operations there, and to the acquisition of additional leasehold interests prospective for the Wolfcamp, Bone Spring and other liquids-rich plays in the Delaware Basin. The remaining 22% of our capital expenditures (excluding capital expenditures associated with the HEYCO Merger) were directed to our operated drilling and completion activities in the Eagle Ford shale in the early part of 2015 and to our participation in a number of non-operated wells drilled and completed in the Haynesville shale throughout 2015, as noted above.

We increased our leasehold position significantly in the Delaware Basin during 2015. At December 31, 2014, we held approximately 92,700 gross (66,100 net) acres in Southeast New Mexico and West Texas. Including the acreage added as part of the HEYCO Merger and other transactions completed during 2015, at December 31, 2015, our total acreage position in this area had increased to 157,100 gross (88,800 net) acres, primarily in the Delaware Basin in Loving County, Texas and Lea and Eddy Counties, New Mexico.

Our oil production, natural gas production and average daily oil equivalent production during 2015 were the best in Matador's history. Our average daily oil equivalent production for the year ended December 31, 2015 was 24,955 BOE per day, including 12,306 Bbl of oil per day and 75.9 MMcf of natural gas per day, an increase of 55% as compared to 16,082 BOE per day, including 9,095 Bbl of oil per day and 41.9 MMcf of natural gas per day, for the year ended December 31, 2014. Our average daily oil production in 2015 of 12,306 Bbl of oil per day increased 35%, as compared to an average daily oil production of 9,095 Bbl of oil per day in 2014. This increase in oil production was primarily a result of increased oil production from newly drilled and completed wells in the Delaware Basin, as well as from newly drilled and completed wells in the Eagle Ford shale in early 2015. Our average daily natural gas production of 75.9 MMcf per day for the year ended December 31, 2015 increased 81% from 41.9 MMcf per day for the year ended December 31, 2014. This increase in natural gas production is primarily attributable to new, non-operated Haynesville shale wells completed and placed on production by Chesapeake on our Elm Grove properties in Northwest Louisiana in the latter half of 2014 and throughout 2015, but also includes increased natural gas production associated with our operations in both the Delaware Basin and the Eagle Ford shale. Oil production comprised 49% of our total production (using a conversion ratio of one Bbl of oil per six Mcf of natural gas) for the year ended December 31, 2015, as compared to 57% for the year ended December 31, 2014.

For the year ended December 31, 2015, our oil and natural gas revenues were $278.3 million, a decrease of 24% from oil and natural gas revenues of $367.7 million for the year ended December 31, 2014. Our oil revenues and natural gas revenues decreased 30% and 3% to approximately $203.4 million and $75.0 million, respectively, as a result of significantly lower oil and natural gas prices realized for the year ended December 31, 2015, as compared to $290.0 million and $77.7 million, respectively, for the year ended December 31, 2014. Adjusted EBITDA for the year ended December 31, 2015 was $223.2 million, a decrease of 15% from Adjusted EBITDA of $262.9 million reported for the year ended December 31, 2014. Our Adjusted EBITDA of $223.2 million for the year ended December 31, 2015 was the second best Adjusted EBITDA result in Matador's history, surpassed only by record Adjusted EBITDA of $262.9 million reported for 2014. Adjusted EBITDA is a non-GAAP financial measure. For a definition of Adjusted EBITDA

and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see "Selected Financial Data — Non-GAAP Financial Measures."
At December 31, 2015, our estimated total proved oil and natural gas reserves were 85.1 million BOE, including 45.6 million Bbl of oil and 236.9 Bcf of natural gas, with a PV-10 of $541.6 million and a Standardized Measure of $529.2 million. At December 31, 2014, our estimated proved oil and natural gas reserves were 68.7 million BOE, including 24.2 million Bbl of oil and 267.1 Bcf of natural gas, with a PV-10 of $1.04 billion and a Standardized Measure of $913.3 million. Our estimated total proved reserves of 85.1 million BOE at December 31, 2015 represented a 24% year-over-year increase, as compared to 68.7 million BOE at December 31, 2014. Our estimated proved oil reserves of 45.6 million Bbl at December 31, 2015 increased 89%, as compared to 24.2 million Bbl at December 31, 2014. Our proved oil reserves in the Delaware Basin increased almost four-fold to 31.4 million Bbl at December 31, 2015, as compared to 8.1 million Bbl at December 31, 2014, resulting from our ongoing delineation and development operations in the Delaware Basin. Proved oil reserves comprised 54%

of our total proved reserves at December 31, 2015, as compared to 35% at December 31, 2014. These reserves estimates were based on evaluations prepared by our engineering staff and have been audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers. Standardized Measure represents the present value of estimated future net cash flows from proved reserves, less estimated future development, production, plugging and abandonment costs and income tax expenses, discounted at 10% per annum to reflect the timing of future cash flows. Standardized Measure is not an estimate of the fair market value of our properties. PV-10 is a non-GAAP financial measure. For a reconciliation of PV-10 to Standardized Measure, see "Business — Estimated Proved Reserves."

2016 Capital Expenditure Budget

In response to the continued decline in oil and natural gas prices experienced throughout 2015 and into early 2016, we have reduced our 2016 estimated capital expenditure budget to $325.0 million, a decrease of 33%, as compared to actual capital expenditures of $482.1 million (excluding capital expenditures associated with the HEYCO Merger) for the year ended December 31, 2015. We plan to operate three contracted drilling rigs in the Delaware Basin throughout 2016, although should oil prices drop and remain below $30.00 per Bbl, we have the flexibility to reduce the number of rigs we are operating from three rigs to two rigs, either for a short time or for the remainder of 2016, beginning as early as the second quarter of 2016. This could reduce our estimated 2016 capital expenditures by approximately $50.0 million. Our 2016 estimated capital expenditure budget of $325.0 million (assuming a three-rig program) consists of approximately $260.0 million for drilling, completions, facilities and infrastructure, $40.0 million principally for the completion of new midstream facilities in the Delaware Basin to support our operations there and $25.0 million for land acquisitions and seismic data, primarily in the Delaware Basin. Development of our Delaware Basin assets will be the primary driver of our projected growth in 2016. Approximately $315.0 million, or 97%, of our 2016 estimated capital expenditures will be allocated to the further delineation and development of our growing leasehold position in the Delaware Basin. Our 2016 Delaware Basin drilling program will focus on the development of the Wolf and Rustler Breaks prospect areas and the further delineation and development of the Ranger and Arrowhead prospect areas. The $40.0 million in midstream capital expenditures is expected to primarily fund completion of the construction and installation of a cryogenic natural gas processing plant with approximately 60 MMcf per day of inlet capacity and a natural gas gathering system in the Rustler Breaks prospect area in Eddy County, New Mexico. This plant is expected to be operational by the third quarter of 2016.

We do not plan to drill any operated Eagle Ford shale wells in South Texas or Haynesville shale wells in Northwest Louisiana and East Texas during 2016. Approximately $5.6 million, or 2%, of our 2016 estimated capital expenditures will be allocated to the Eagle Ford shale to allow for the installation of pumping units on certain properties and for lease extensions and acquisitions, if desired, and approximately $4.4 million, or just over 1%, of our 2016 estimated capital expenditures will be allocated to participation in non-operated Haynesville shale wells. Approximately 92% of our Eagle Ford acreage and essentially all of our Haynesville and Cotton Valley acreage was either held by production at December 31, 2015 or not burdened by lease expirations before 2017.

At December 31, 2015, we had $61.1 million in cash (including restricted cash) and $374.4 million in undrawn borrowing capacity under our Credit Agreement (after giving effect to outstanding letters of credit). As a result, we expect to fund our 2016 drilling program through a combination of operating cash flows and borrowings under our Credit Agreement (assuming availability under our borrowing base). We may also consider funding a portion of our 2016 capital expenditures through additional credit arrangements, potential joint ventures, the sale of midstream or other assets or acreage and the potential issuance of equity, debt or convertible securities, none of which may be available. While we have budgeted approximately $325.0 million of capital expenditures for 2016, the aggregate amount of capital we expend may fluctuate materially based on market conditions, the actual costs to drill, complete and place on production operated or non-operated wells, our drilling results, the actual costs of our midstream activities, other opportunities that may become available to us and our ability to obtain capital.

Table of Contents

Revenues

Our revenues are derived primarily from the sale of oil, natural gas and natural gas liquids production. Our revenues may vary significantly from period to period as a result of changes in volumes of production sold or changes in oil, natural gas or natural gas liquids prices.

The following table summarizes our revenues and production data for the periods indicated.

	Year Ended December 31,		
	2015	2014	2013
Operating Data:			
Revenues (in thousands): (1)			
Oil	$203,355	$290,026	$212,833
Natural gas	74,985	77,686	56,197
Total oil and natural gas revenues	278,340	367,712	269,030
Realized gain (loss) on derivatives	77,094	5,022	(909)
Unrealized (loss) gain on derivatives	(39,265)	58,302	(7,232)
Total revenues	$316,169	$431,036	$260,889
Net Production Volumes: (1)			
Oil (MBbl)	4,492	3,320	2,133
Natural gas (Bcf)	27.7	15.3	12.9
Total oil equivalent (MBOE) (2)	9,109	5,870	4,285
Average daily production (BOE/d) (2)	24,955	16,082	11,740
Average Sales Prices:			
Oil, with realized derivatives (per Bbl)	$59.13	$88.94	$98.67
Oil, without realized derivatives (per Bbl)	$45.27	$87.37	$99.79
Natural gas, with realized derivatives (per Mcf)	$3.24	$5.06	$4.47
Natural gas, without realized derivatives (per Mcf)	$2.71	$5.08	$4.35

(1) We report our production volumes in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Revenues associated with natural gas liquids are included with our natural gas revenues.

(2) Estimated using a conversion ratio of one Bbl of oil per six Mcf of natural gas.

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

Oil and natural gas revenues. Our oil and natural gas revenues decreased $89.4 million to $278.3 million, or a decrease of 24% for the year ended December 31, 2015, as compared to $367.7 million for the year ended December 31, 2014. Our oil revenues decreased $86.7 million, a decrease of 30%, to $203.4 million for the year ended December 31, 2015, as compared to $290.0 million for the year ended December 31, 2014. The decrease in oil revenues resulted from a significantly lower weighted average oil price realized for the year ended December 31, 2015 of $45.27 per Bbl, as compared to $87.37 per Bbl realized for the year ended December 31, 2014. The lower weighted average oil price was partially mitigated by the 35% increase in our oil production to 4.5 million Bbl of oil for the year ended December 31, 2015, or about 12,306 Bbl of oil per day, as compared to just over 3.3 million Bbl of oil, or about 9,095 Bbl of oil per day, for the year ended December 31, 2014. This increased oil production was primarily a result of newly drilled and completed wells in the Delaware Basin, as well as from newly drilled and completed wells in the Eagle Ford shale in early 2015. Our natural gas revenues decreased $2.7 million, or a decrease of 3%, to $75.0 million for the year ended December 31, 2015, as compared to $77.7 million for the year ended December 31, 2014. The decrease in natural gas revenues resulted from a lower weighted average natural gas price realized for the year ended December 31, 2015 of $2.71 per Mcf, as compared to $5.08 per Mcf realized for the year ended December 31, 2014. The lower weighted average natural gas price was partially mitigated by the 81% increase in our natural gas production to 27.7 Bcf for the year ended December 31, 2015, as compared to 15.3 Bcf for the year ended December

31, 2014. The increased natural gas production was primarily attributable to new, non-operated Haynesville shale wells completed and placed on production on our Elm Grove properties in Northwest Louisiana during the latter half of 2014 and into 2015, but also included increased natural gas production associated with our operations in the Delaware Basin and the Eagle Ford shale.

Realized gain (loss) on derivatives. Our realized net gain on derivatives was $77.1 million for the year ended December 31, 2015, as compared to a realized net gain of $5.0 million for the year ended December 31, 2014. We realized gains of $62.3 million, $12.7 million and $2.2 million from our oil, natural gas and natural gas liquids (“NGL”) derivative contracts, respectively, for the year ended December 31, 2015 due to oil and natural gas prices being below the floor prices of most of our costless collar contracts and NGL prices being below the fixed prices of all of our swap contracts. Our realized net gain on derivatives was $5.0 million for the year ended December 31, 2014. We realized a gain from our oil derivative contracts of approximately $5.2 million and a gain of $0.5 million from our NGL derivative contracts for the year ended December 31, 2014 due to oil prices being below the floor prices of some of our costless collar contracts and NGL prices being below the fixed prices of some of our swap contracts, respectively, especially during the latter part of 2014. These gains were partially offset by a loss of $0.7 million on our natural gas derivative contracts, due to natural gas prices being in excess of the ceiling prices of our natural gas costless collar contracts, especially in the early months of 2014. We realized an average gain of approximately $22.89 per Bbl hedged on all of our open oil costless collar contracts during the year ended December 31, 2015, as compared to an average gain of $2.00 per Bbl hedged for the year ended December 31, 2014. Our oil volumes hedged for the year ended December 31, 2015 were also 5% higher as compared to the year ended December 31, 2014. We realized an average gain of approximately $0.73 per MMBtu hedged on all of our open natural gas costless collar contracts during the year ended December 31, 2015, as compared to an average loss of approximately $0.06 per MMBtu hedged on all of our open natural gas costless collar contracts during the year ended December 31, 2014. Our total natural gas volumes hedged for the year ended December 31, 2015 were also 38% higher than the total natural gas volumes hedged for the year ended December 31, 2014.

Unrealized gain (loss) on derivatives. Our unrealized loss on derivatives was approximately $39.3 million for the year ended December 31, 2015, as compared to an unrealized gain of approximately $58.3 million for the year ended December 31, 2014. During the year ended December 31, 2015, the net fair value of our open oil, natural gas and NGL derivatives contracts decreased to approximately $16.3 million from $55.5 million for the year ended December 31, 2014, resulting in an unrealized loss on derivatives of approximately $39.3 million for the year ended December 31, 2015. During the year ended December 31, 2015, the net fair value of our open oil, natural gas and NGL derivative contracts decreased by $31.9 million, $5.4 million and $1.9 million, respectively, due primarily to the realized gains from oil, natural gas and NGL derivative contracts settled during the year ended December 31, 2015.

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

Oil and natural gas revenues. Our oil and natural gas revenues increased $98.7 million to $367.7 million, or an increase of about 37% for the year ended December 31, 2014, as compared to $269.0 million for the year ended December 31, 2013. This increase in oil and natural gas revenues corresponds with an increase of 37% in our oil and natural gas production to 5.9 million BOE for the year ended December 31, 2014 from 4.3 million BOE for the year ended December 31, 2013. Our oil revenues increased $77.2 million, an increase of 36%, to $290.0 million for the year ended December 31, 2014, as compared to $212.8 million for the year ended December 31, 2013. Our oil production increased 56% to over 3.3 million Bbl of oil, or about 9,095 Bbl of oil per day, as compared to approximately 2.1 million Bbl of oil, or about 5,843 Bbl of oil per day, for the year ended December 31, 2013 due to our ongoing development operations in the Eagle Ford shale and from the better-than-expected performance of a number of our initial wells in the Delaware Basin. Had the weighted average oil price we realized in 2014 remained consistent with the oil price we realized in 2013, the increase in oil production would have resulted in an increase in oil revenue of $118.5 million for the year ended December 31, 2014. This potential increase of $41.2 million in oil revenues was not fully realized in 2014, however, as a result of a lower oil price of $87.37 per Bbl realized for the year ended December 31, 2014, as compared to $99.79 per Bbl realized for the year ended December 31, 2013. Our natural gas revenues increased $21.5 million, an increase of 38%, to $77.7 million for the year ended December 31, 2014, as compared to $56.2 million for the year ended December 31, 2013. Our natural gas production increased 18% to approximately 15.3 Bcf for the year ended December 31, 2014, as compared to approximately 12.9 Bcf for the year ended December 31, 2013 due to our ongoing development activities in the Eagle Ford shale and the Delaware Basin and to the natural gas production resulting from new, non-operated Haynesville shale wells completed and placed on production on our Elm Grove properties in Northwest Louisiana during the latter half of 2014. This increase in natural gas production in 2014 resulted in increased natural gas revenues of $10.4 million, and the remaining increase in natural gas revenues of $11.1 million was due to a higher natural gas price of $5.08 per Mcf realized for the year ended December 31, 2014, as compared to $4.35 per Mcf realized for the year ended December 31, 2013.

Realized gain (loss) on derivatives. Our realized net gain on derivatives was approximately $5.0 million for the year ended December 31, 2014, as compared to a realized net loss of approximately $0.9 million for the year ended

December 31, 2013. We realized a gain from our oil contracts of $5.2 million and a gain of $0.5 million from our NGL contracts for the year ended December 31, 2014 due to oil prices being below the floor prices of some of our costless collar contracts and NGL prices being below the fixed prices of some of our swap contracts, respectively, especially during the latter part of 2014. These gains were partially offset by a loss of approximately $0.7 million on our natural gas contracts due to natural gas prices being in excess of the ceiling prices of our natural gas costless collar contracts, especially in the early months of 2014. Our realized net loss on derivatives was $0.9 million for the year ended December 31, 2013. We realized a loss from our oil contracts of approximately $2.4 million for the year ended December 31, 2013 due to oil prices being in excess of the ceiling prices of some of our costless collar contracts and the fixed prices of our swap contracts. This loss was partially offset by gains of approximately $0.8 million and $0.7 million on our natural gas and NGL derivative contracts, respectively, due to the respective commodity prices being below the floor prices of our natural gas costless collar contracts and the fixed prices of our NGL swap contracts. We realized an average gain of approximately $2.00 per Bbl hedged on all of our oil costless collar

contracts during the year ended December 31, 2014, as compared to an average loss of $1.42 per Bbl hedged for the year ended December 31, 2013. Our oil volumes hedged for the year ended December 31, 2014 were also 53% higher as compared to the year ended December 31, 2013. We realized an average loss of approximately $0.06 per MMBtu hedged on all of our open natural gas costless collar contracts during the year ended December 31, 2014, as compared to an average gain of approximately $0.10 per MMBtu hedged on all of our open natural gas costless collar contracts during the year ended December 31, 2013. Our total natural gas volumes hedged for the year ended December 31, 2014 were also 46% higher than the total natural gas volumes hedged for the year ended December 31, 2013.
Unrealized gain (loss) on derivatives. Our unrealized gain on derivatives was approximately $58.3 million for the year ended December 31, 2014, as compared to an unrealized loss of approximately $7.2 million for the year ended December 31, 2013. During the year ended December 31, 2014, the net fair value of our open oil, natural gas and natural gas liquids derivatives contracts increased to approximately $55.5 million, from $(2.8) million for the year ended December 31, 2013, resulting in an unrealized gain on derivatives of approximately $58.3 million for the year ended December 31, 2014. During the year ended December 31, 2014, the net fair value of our open oil, natural gas and NGL derivative contracts increased by $47.2 million, $9.1 million and $2.0 million, respectively, due primarily to the decrease in the underlying commodities' futures prices as compared to the year ended December 31, 2013.

Expenses

The following table summarizes our operating expenses and other income (expense) for the periods indicated.

	Year Ended December 31,		
	2015	2014	2013
(In thousands, except expenses per BOE)			
Expenses:			
Production taxes and marketing	$35,535	$33,172	$20,973
Lease operating	58,193	51,353	38,720
Depletion, depreciation and amortization	178,847	134,737	98,395
Accretion of asset retirement obligations	734	504	348
Full-cost ceiling impairment	801,166	—	21,229
General and administrative	50,105	32,152	20,779
Total expenses	1,124,580	251,918	200,444
Operating (loss) income	(808,411)	179,118	60,445
Other income (expense):			
Net gain (loss) on asset sales and inventory impairment	908	—	(192)
Interest expense	(21,754)	(5,334)	(5,687)
Interest and other income	2,365	1,345	225
Total other expense	(18,481)	(3,989)	(5,654)
(Loss) income before income taxes	(826,892)	175,129	54,791
Total income tax (benefit) provision	(147,368)	64,375	9,697
Net (income) loss attributable to non-controlling interest in subsidiaries	(261)	17	—
Net (loss) income attributable to Matador Resources Company shareholders	$(679,785)	$110,771	$45,094
Expenses per BOE:			
Production taxes and marketing	$3.90	$5.65	$4.89
Lease operating	$6.39	$8.75	$9.04
Depletion, depreciation and amortization	$19.63	$22.95	$22.96
General and administrative	$5.50	$5.48	$4.85

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

Production taxes and marketing. Our production taxes and marketing expenses increased by $2.4 million to $35.5 million, an increase of 7%, for the year ended December 31, 2015, as compared to $33.2 million for the year ended December 31, 2014. On a unit-of-production basis, however, our production taxes and marketing expenses decreased by 31% to $3.90 per BOE for the year ended December 31, 2015, as compared to $5.65 per BOE for the year ended

December 31, 2014. The increase in production taxes and marketing expenses on an absolute basis was primarily attributable to higher natural gas marketing expenses of $22.4 million for the year ended December 31, 2015, as compared to natural gas marketing expenses of $15.2 million for the year ended December 31, 2014, an increase of $7.2 million, due to the 81% increase in our natural gas production to 27.7 Bcf for the year ended December 31, 2015, as compared to 15.3 Bcf of natural gas production for the year ended December 31, 2014. This increase was partially offset by a decrease in our production taxes of $4.8 million to $13.2 million for the year ended December 31, 2015, as compared to $18.0 million for the year ended December 31, 2014, primarily due to the 30% decrease in oil revenues for the year ended December 31, 2015, as compared to the year ended December 31, 2014.

Lease operating expenses. Our lease operating expenses increased by $6.8 million to $58.2 million, an increase of 13%, for the year ended December 31, 2015, as compared to $51.4 million for the year ended December 31, 2014. Our lease operating expenses per unit of production decreased 27% to $6.39 per BOE for the year ended December 31, 2015, as compared to $8.75 per BOE for the year ended December 31, 2014. Our total oil and natural gas production increased 55% to approximately 9.1 million BOE for the year ended December 31, 2015 from approximately 5.9 million BOE for the year ended December 31, 2014, including an increase of 35% in oil production to approximately 4.5 million Bbl for the year ended December 31, 2015, as compared to just over 3.3 million Bbl for the year ended December 31, 2014, which would typically result in higher lease operating expenses. Oil production was 49% of total production by volume for the year ended December 31, 2015, as compared to 57% of total production by volume for the year ended December 31, 2014. The decrease achieved in lease operating expenses on a unit-of-production basis was attributable to several key factors, including (i) no clean-out operations on offsetting producing wells as a result of fracturing operations on newly drilled Eagle Ford wells as compared to the same period in 2014, (ii) a decrease in salt water disposal costs on a per barrel basis, particularly in the Delaware Basin, (iii) reduced service costs impacting lease operating expenses and (iv) a higher percentage of natural gas production, including a significant increase in Haynesville natural gas production, which typically has lower operating costs due to its lack of associated oil and water production. A joint venture controlled by us drilled, completed and began injecting salt water into a new disposal well in the Wolf prospect area in Loving County, Texas in January 2015, which has reduced salt water disposal costs in this area. A second salt water disposal well has been drilled and tested in the Wolf prospect area and began disposing of salt water in the fourth quarter of 2015. At December 31, 2015, this well was operating with temporary facilities, but it is expected to be fully operational with permanent facilities in the latter part of the first quarter of 2016.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $44.1 million to $178.8 million, an increase of 33%, for the year ended December 31, 2015, as compared to $134.7 million for the year ended December 31, 2014. On a unit-of-production basis, however, our depletion, depreciation and amortization expenses decreased 15% to $19.63 per BOE for the year ended December 31, 2015, as compared to $22.95 per BOE for the year ended December 31, 2014. The absolute increase in our depletion, depreciation and amortization expenses reflects an increase of approximately 55% in our total oil and natural gas production to 9.1 million BOE for the year ended December 31, 2015 from 5.9 million BOE for the year ended December 31, 2014. The 15% decrease in the per-unit-of-production depletion, depreciation and amortization expenses resulted from the 24% increase in total proved oil and natural gas reserves from 68.7 million BOE at December 31, 2014 to 85.1 million BOE at December 31, 2015, which reserves were added at a lower cost per BOE, as well as from the decrease in unamortized property costs resulting from the full-cost ceiling impairments recorded in 2015.

Full-cost ceiling impairment. Due primarily to the sharp decline in oil and natural gas prices during 2015, at December 31, 2015, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the cost center ceiling. As a result, we recorded an impairment charge of $801.2 million, exclusive of tax effect, to our net capitalized costs. This charge is reflected in our statement of operations for the year ended December 31, 2015, with the related deferred income tax credit recorded net of a valuation allowance. No impairment to the net carrying value of our oil and natural gas properties and no corresponding charge resulting from a full-cost ceiling impairment was recorded during the year ended December 31, 2014.

In determining the full-cost ceiling impairment at December 31, 2015, we estimated the PV-10 of our total proved oil and natural gas reserves using the unweighted arithmetic average of oil and natural gas prices as of the first day of each month for the trailing 12-month period ended December 31, 2015 as required under the guidelines established by the SEC, which were $46.79 per Bbl and $2.59 per MMBtu, respectively. If the unweighted arithmetic average of oil and natural gas prices as of the first day of each month for the trailing 12-month period ended December 31, 2015 had been $42.19 per Bbl and $2.41 per MMBtu, respectively, while all other factors remained constant, our full-cost ceiling would have been reduced by an additional $128.9 million on a pro forma basis. The aforementioned pro forma prices, as estimated for the 12-month period April 2015 through March 2016, were calculated using a 12-month unweighted arithmetic average of oil and natural gas prices, which included the oil and natural gas prices on the first day of the month for the 11 months ended February 2016, with the price for February 2016 being held constant for March 2016. This pro forma increase in the excess of our net capitalized costs above the full-cost ceiling is attributable to a pro forma reduction of $128.9 million in the PV-10 of our total proved oil and natural gas reserves, including a pro forma decrease in our estimated total proved reserves to 81.2 million BOE, or a reduction of approximately 5%, from our reported estimated proved reserves of 85.1 million BOE at December 31, 2015, primarily attributable to certain proved undeveloped locations that would no longer be classified as proved undeveloped reserves using the pro forma prices. This calculation of the impact of lower commodity prices on our estimated total proved oil and natural gas reserves and our full-cost ceiling was prepared based on the presumption that all other inputs and assumptions are held constant with the exception of oil and natural gas prices. Therefore, this calculation strictly isolates the impact of commodity prices on our full-cost ceiling and proved reserves. The impact of prices is only one of several variables in the estimation of our proved reserves and full-cost ceiling and other factors could have a significant impact on our future proved reserves and the present value of future cash flows. The other factors that impact future estimates of proved reserves include, but are not limited to, extensions and discoveries, acquisitions of proved reserves, changes in drilling and completion and operating costs, drilling results, revisions due to well performance and other factors, changes in development plans and production, among others. There are numerous uncertainties inherent in the estimation of proved oil and natural gas reserves and accounting for oil and natural gas properties in subsequent periods and this pro forma estimate should not be construed as indicative of our development plans or future results.

General and administrative. Our general and administrative expenses increased by $18.0 million to $50.1 million, an increase of 56%, for the year ended December 31, 2015, as compared to $32.2 million for the year ended December 31, 2014. The increase in our general and administrative expenses was primarily attributable to increased payroll expenses associated with additional personnel joining the Company during the year ended December 31, 2015 to support our increased land, geoscience, drilling, completion, production, accounting and administration functions, including the addition of 29 new employees in Roswell, New Mexico as a result of the HEYCO Merger in late February 2015. The remaining increase is largely due to a $4.0 million increase in non-cash stock-based compensation expenses to $9.5 million for the year ended December 31, 2015, as compared to $5.5 million for the year ended December 31, 2014. The increase in our non-cash stock-based compensation expense was attributable to the increased expense related to the continued vesting of awards granted from 2012 through 2015 of $9.5 million for the year ended December 31, 2015, as compared to $5.3 million for the year ended December 31, 2014. This increase was partially offset by the decreased expense related to our liability-based stock options of $0.1 million for the year ended December 31, 2015, as compared to $0.2 million for the year ended December 31, 2014. This decreased expense related to our liability-based stock options was attributable to the slight decrease in our stock price from $20.23 per share at December 31, 2014 to $19.77 per share at December 31, 2015. Our general and administrative expenses increased by less than 1% on a unit-of-production basis to $5.50 per BOE for the year ended December 31, 2015, as compared to $5.48 per BOE for the year ended December 31, 2014.

Interest expense. For the year ended December 31, 2015, we incurred total interest expense of approximately $25.7 million. We capitalized approximately $3.9 million of our interest expense on certain qualifying projects for the year ended December 31, 2015 and expensed the remaining $21.8 million to operations. For the year ended December 31, 2014, we incurred total interest expense of approximately $8.2 million. We capitalized approximately $2.8 million of our interest expense on certain qualifying projects for the year ended December 31, 2014 and expensed the remaining $5.3 million to operations. The increase in total interest expense of $17.5 million for the year ended December 31, 2015, as compared to the year ended December 31, 2014, was attributable to an increase in both the average debt outstanding and the interest rate of 6.875% under the senior notes in 2015, as compared to the effective interest rate of approximately 3.3% under our Credit Agreement in 2014. In late April 2015, we used a portion of the net proceeds from the April 2015 senior notes and equity offerings to repay a total of $465.0 million of outstanding borrowings under our Credit Agreement. At December 31, 2015, we had no outstanding borrowings under our Credit Agreement, $0.6 million in outstanding letters of credit and $400.0 million in outstanding senior notes. Due to the higher interest rate on the senior notes as compared to the interest rates under the Credit Agreement, we expect to incur increased interest expense in future periods.

Total income tax (benefit) provision. At December 31, 2015, our deferred tax assets exceeded our deferred tax liabilities and, as a result, we recorded a valuation allowance of $154.3 million against the deferred tax assets. The total income tax expense for the year ended December 31, 2015 differed from amounts computed by applying the U.S. federal statutory tax rates to the pre-tax loss due primarily to the recording of a valuation allowance against the net deferred tax asset position as a result of the full-cost ceiling impairment recorded for the year ended December 31, 2015. We recorded a total income tax benefit of $147.4 million for the year ended December 31, 2015. The total income tax benefit of $147.4 million for the year ended December 31, 2015 is comprised of a current tax expense of $3.0 million, which represents our estimated alternative minimum tax liability (“AMT”), and a deferred tax benefit of $150.3 million. For the year ended December 31, 2014, we incurred an estimated AMT liability of $0.1 million, which represents the current portion of the income tax provision. The remaining income tax provision of $64.2 million represents deferred taxes for the year ended December 31, 2014. Our effective tax rate for the year ended December 31, 2014 was 36.8%. Total income tax expense for the year ended December 31, 2014 differed from amounts computed by applying the U.S. federal statutory tax rates to pre-tax income due primarily due to the impact of permanent differences between book and taxable income.

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

Production taxes and marketing. Our production taxes and marketing expenses increased by $12.2 million to $33.2 million, an increase of 58%, for the year ended December 31, 2014, as compared to $21.0 million for the year ended December 31, 2013. On a unit-of-production basis, however, our production taxes and marketing expenses increased by only 16% to $5.65 per BOE for the year ended December 31, 2014, as compared to $4.89 per BOE for the year ended December 31, 2013. Much of this increase was attributable to increased production taxes associated with the large increase in our oil production during

2014 resulting from our drilling operations in the Eagle Ford shale, as well as initial production from our newly drilled wells in the Delaware Basin. Our total production was comprised of approximately 57% oil and 43% natural gas during the year ended December 31, 2014, as compared to approximately 50% oil and 50% natural gas during the year ended December 31, 2013. The increase in production taxes and marketing expenses during the year ended December 31, 2014 also reflected the increase in natural gas production from the Eagle Ford shale where natural gas production taxes are higher than production taxes associated with Haynesville shale natural gas in Louisiana, as well as increased marketing expenses on certain of our non-operated Eagle Ford and Haynesville properties in 2014.

Lease operating expenses. Our lease operating expenses increased by $12.6 million to $51.4 million, an increase of 33%, for the year ended December 31, 2014, as compared to $38.7 million for the year ended December 31, 2013. Our lease operating expenses per unit of production decreased 3% to $8.75 per BOE for the year ended December 31, 2014, as compared to $9.04 per BOE for the year ended December 31, 2013. Our total oil and natural gas production increased 37% to approximately 5.9 million BOE for the year ended December 31, 2014 from approximately 4.3 million BOE for the year ended December 31, 2013, including an increase of 56% in oil production to over 3.3 million Bbl for the year ended December 31, 2014, as compared to 2.1 million Bbl for the year ended December 31, 2013, which would typically result in higher lease operating expenses. Oil production was 57% of total production by volume for the year ended December 31, 2014, as compared to only 50% of total production by volume for the year ended December 31, 2013. The decrease achieved in lease operating expenses on a unit-of-production basis was primarily attributable to the progress we have made in reducing our lease operating expenses in the Eagle Ford shale during the last twelve months, which was primarily attributable to (i) the installation of permanent production facilities on almost all of our Eagle Ford properties, alleviating the need for the extended use of flowback equipment to produce newly completed Eagle Ford wells, (ii) the early use of gas lift on most of our newly completed Eagle Ford wells, (iii) a decrease in salt water disposal costs on a per barrel basis and (iv) continued improvement in overall operational processes in our South Texas operations.

Depletion, depreciation and amortization. Our depletion, depreciation and amortization expenses increased by $36.3 million to $134.7 million, an increase of 37%, for the year ended December 31, 2014, as compared to $98.4 million for the year ended December 31, 2013. On a unit-of-production basis, however, our depletion, depreciation and amortization expenses remained essentially flat at $22.95 per BOE for the year ended December 31, 2014, as compared to $22.96 per BOE for the year ended December 31, 2013. The absolute increase in our depletion, depreciation and amortization expenses reflects an increase of approximately 37% in our total oil and natural gas production to 5.9 million BOE for the year ended December 31, 2014 from 4.3 million BOE for the year ended December 31, 2013. This increase on an absolute basis was offset on a unit-of-production basis by the increase in our proved oil and natural gas reserves of 33% to 68.7 million BOE at December 31, 2014 from 51.7 million BOE at December 31, 2013. This increase in total proved oil and natural gas reserves was primarily attributable to the continued development of our acreage in the Eagle Ford shale and the initial delineation and development of our acreage in the Delaware Basin. As a result of this increase in proved oil and natural gas reserves, depletion, depreciation and amortization expenses on a unit-of production basis remained essentially flat year-over-year.

Full-cost ceiling impairment. No impairment to the net carrying value of our oil and natural gas properties and no corresponding charge resulting from a full-cost ceiling impairment was recorded during the year ended December 31, 2014. No impairment to the net carrying value of our oil and natural gas properties and no corresponding charge resulting from a full-cost ceiling impairment was recorded during the quarters ended December 31, 2013, September 30, 2013 or June 30, 2013. During the quarter ended March 31, 2013, the net capitalized costs of our oil and natural gas properties less related deferred income taxes exceeded the full-cost ceiling. As a result, we recorded an impairment charge of $21.2 million, exclusive of tax effect, to the net capitalized costs of our oil and natural gas properties. This full-cost ceiling impairment of $21.2 million is reflected in our operating expenses for the year ended December 31, 2013, and resulted primarily from the continued low weighted average index price for natural gas used to estimate proved natural gas reserves at March 31, 2013, which was $2.95 per MMBtu for the period of time from April 2012 through March 2013.

General and administrative. Our general and administrative expenses increased by $11.4 million to $32.2 million, an increase of 55%, for the year ended December 31, 2014, as compared to $20.8 million for the year ended December 31, 2013. The increase in our general and administrative expenses was primarily attributable to increased payroll expenses associated with additional personnel joining the Company during the year ended December 31, 2014 to support our increased land, geoscience, drilling, completion and production operations. The remaining increase is largely due to a $1.6 million increase in non-cash stock-based compensation expenses to $5.5 million for the year ended December 31, 2014, as compared to $3.9 million for the year ended December 31, 2013. The increase in our non-cash stock-based compensation expense was attributable to the increased expense related to the continued vesting of awards granted in 2012, 2013 and 2014 of $5.3 million for the year ended December 31, 2014, as compared to $2.9 million for the year ended December 31, 2013. This increase was partially offset by the decreased expense related to our liability-based stock options of $0.2 million for the year ended December 31, 2014, as compared to $1.0 million for the year ended December 31, 2013. This decreased expense related to our liability-based stock options was attributable to the smaller increase in our stock price from $18.64 per share at December 31, 2013 to $20.23 per share at December 31, 2014, as compared to the larger increase from $8.20 per share at December 31, 2012 to $18.64 per share at December 31, 2013. Our general and administrative expenses increased by only 13% on a unit-of-production basis to $5.48 per BOE for the year ended December 31, 2014, as compared to $4.85 for the year ended December 31, 2013.

Interest expense. For the year ended December 31, 2014, we incurred total interest expense of approximately $8.2 million. We capitalized approximately $2.8 million of our interest expense on certain qualifying projects for the year ended December 31, 2014 and expensed the remaining $5.3 million to operations. For the year ended December 31, 2013, we incurred total interest expense of approximately $7.6 million. We capitalized approximately $1.9 million of our interest expense on certain qualifying projects for the year ended December 31, 2013 and expensed the remaining $5.7 million to operations. The increase in total interest expense for the year ended December 31, 2014 of $0.6 million, as compared to the year ended December 31, 2013, was primarily attributable to higher average outstanding borrowings under our Credit Agreement during 2014, as compared to average outstanding borrowings under our Credit Agreement during 2013. In May 2014, we used a portion of the net proceeds of our public equity offering to repay $180.0 million of outstanding borrowings under our Credit Agreement. At December 31, 2014, we had $340.0 million in borrowings and $0.6 million in letters of credit outstanding under our Credit Agreement, and the effective interest rate on our borrowings was approximately 3.3% per annum. In September 2013, we used a portion of the net proceeds of our September 2013 public equity offering to repay $130.0 million of outstanding borrowings under our Credit Agreement. At December 31, 2013, we had $200.0 million in borrowings and $0.3 million in letters of credit outstanding under our Credit Agreement.

Total income tax provision. We recorded a total income tax provision of approximately $64.4 million for the year ended December 31, 2014, as compared to a total income tax provision of approximately $9.7 million for the year ended December 31, 2013. For the year ended December 31, 2014, we incurred an estimated AMT liability of $0.1 million, which represents the current portion of the income tax provision. The remaining income tax provision of $64.2 million represents deferred taxes for the year ended December 31, 2014. Our effective tax rate for the year ended December 31, 2014 was 36.8%. Total income tax expense for the year ended December 31, 2014 differed from amounts computed by applying the U.S. federal statutory tax rates to pre-tax income due to the impact of permanent differences between book and taxable income. For the year ended December 31, 2013, we incurred an estimated AMT liability of $0.4 million, which represents the current portion of the income tax provision. The remaining $9.3 million represents deferred taxes for the year ended December 31, 2013. Our effective tax rate for the year ended December 31, 2013 was 17.7%. Total income tax expense for the year ended December 31, 2013 differed from amounts computed by applying the U.S. federal statutory tax rates to pre-tax income due primarily to (i) the reversal of the valuation allowance of approximately $8.9 million on our federal deferred tax assets at December 31, 2012, as our federal deferred tax liability exceeded our federal deferred tax assets for the year ended December 31, 2013, (ii) the reversal of a state valuation allowance of approximately $1.3 million, as we believe we will be able to utilize the state net operating losses prior to their expiration and (iii) the impact of permanent differences between book and taxable income.

Liquidity and Capital Resources

Our primary use of capital has been, and we expect will continue to be during 2016 and for the foreseeable future, for the acquisition, exploration and development of oil and natural gas properties and for related midstream investments. We continually evaluate potential capital sources, including additional borrowings, equity and debt financings, the sale of midstream or other assets and joint ventures, in order to meet our planned capital expenditures and liquidity requirements. Our future success in growing proved reserves and production will be highly dependent on our ability to access outside sources of capital and to generate operating cash flows.

At December 31, 2015, we had cash totaling approximately $16.7 million and restricted cash totaling approximately $44.4 million. Restricted cash represents a portion of the cash paid for the Loving County System by EnLink (as described in Note 5 to the consolidated financial statements in this Annual Report on Form 10-K) directly to a qualified intermediary to facilitate like-kind-exchange transactions for federal income tax purposes, as well as cash held by our less-than-wholly-owned subsidiaries. Not all of the cash deposited with the qualified intermediary was used for like-kind-exchange transactions and, in January 2016, the remaining balance of $42.1 million was returned to us by the qualified intermediary to be used for general corporate purposes. By contractual agreement, the cash in the account held by our less-than-wholly-owned subsidiaries is not to be commingled with other Company cash and is to be used only to fund the capital expenditures and operations of these less-than-wholly-owned subsidiaries.

At December 31, 2015 and February 25, 2016, the borrowing base under our Credit Agreement was $375.0 million. At both dates, we had no outstanding borrowings and approximately $0.6 million in outstanding letters of credit under the Credit Agreement, and we had $400.0 million of outstanding senior notes.

On April 14, 2015, we issued $400.0 million of 6.875% senior notes due 2023 (the "Original Notes") in a private placement. The Original Notes are our senior unsecured obligations, are redeemable as described below and were issued at par value. The net proceeds were used to pay down a portion of the outstanding borrowings under the Credit Agreement and the debt assumed in connection with the HEYCO Merger. The Original Notes mature on April 15, 2023, and interest is payable semi-annually in arrears on April 15 and October 15 of each year. On October 21, 2015, pursuant to a registered exchange offer, we exchanged all of the privately placed Original Notes for a like principal amount of 6.875% senior notes due 2023 that have been registered under the Securities Act (the "Notes"). The terms of such Notes are substantially the same as the terms of the Original Notes except that the transfer restrictions, registration rights and provisions for additional interest relating to the Original Notes do not apply to the Notes.
On April 21, 2015, we completed a public offering of 7,000,000 shares of our common stock. After deducting offering costs totaling approximately $1.2 million, we received net proceeds of approximately $187.6 million. We used a portion of the net proceeds to repay $85.0 million in outstanding borrowings under our Credit Agreement, which amounts may be reborrowed in accordance with the terms of that facility. The remaining $102.6 million of net proceeds was used to fund a portion of our working capital expenditures, including the addition of a third drilling rig in the Delaware Basin in late July 2015 and targeted acquisitions of additional acreage in the Delaware Basin, as well as in the Eagle Ford shale, and for other general working capital needs.
On October 1, 2015, we completed the sale of our wholly-owned subsidiary that owned the Loving County System to EnLink. The Loving County System includes the Processing Plant and approximately six miles of high-pressure gathering pipeline which connects our gathering system to the Processing Plant. Pursuant to the terms of the transaction, EnLink paid cash consideration of approximately $143.4 million, excluding customary purchase price adjustments. In conjunction with the sale of the Loving County System, we dedicated our leasehold interests in Loving County as of the closing date pursuant to a 15-year fixed-fee natural gas gathering and processing agreement and provided a volume commitment in exchange for priority one service. In addition, we retained our natural gas gathering system up to a central delivery point and our other midstream assets in the area, including oil and water gathering systems and salt water disposal wells.
In response to the sharp decrease in oil and natural gas prices experienced throughout 2015 and early 2016, we have reduced our 2016 estimated capital expenditure budget to $325.0 million as compared to actual capital expenditures of $482.1 million (excluding capital expenditures associated with the HEYCO Merger) for the year ended December 31, 2015. Our estimated capital expenditure budget for 2016 of $325.0 million consists of approximately $260.0 million for drilling, completions, facilities and infrastructure, $40.0 million principally for the completion of new midstream facilities in the Delaware Basin to support our operations there and $25.0 million for land acquisitions and seismic data, primarily in the Delaware Basin. Development of our Delaware Basin assets will be the primary driver of our growth in 2016. Approximately $315.0 million, or 97%, of our 2016 estimated capital expenditures will be allocated to further delineation and development of our growing leasehold position in the Delaware Basin. Our 2016 Delaware Basin drilling program will focus on the development of the Wolf and Rustler Breaks prospect areas and the further delineation and development of the Ranger and Arrowhead prospect areas. The $40.0 million in midstream capital expenditures is expected to primarily fund the construction and installation of a cryogenic natural gas processing plant with approximately 60 MMcf per day of inlet capacity and a natural gas gathering system in the Rustler Breaks prospect area in Eddy County, New Mexico. This plant is expected to be operational by the third quarter of 2016.
Exploration and development activities are subject to a number of risks and uncertainties, which could cause these activities to be less successful than we anticipate. A significant portion of our anticipated cash flows from operations in 2016 is expected to come from producing wells and development activities on currently proved properties in the Wolfcamp and Bone Spring plays in the Delaware Basin, the Eagle Ford shale in South Texas and the Haynesville shale in Louisiana. Our existing wells may not produce at the levels we are forecasting and our exploration and development activities in these areas may not be as successful as we anticipate. Additionally, our anticipated cash flows from operations are based upon current expectations of oil and natural gas prices for 2016 and the hedges we currently have in place. We use commodity derivative financial instruments to mitigate our exposure to fluctuations in oil and natural gas prices and to partially offset reductions in our cash flows from operations resulting from declines in

commodity prices. As of February 25, 2016, we had 44% and 44% of our estimated remaining 2016 oil and natural gas production, respectively, hedged. We currently have no hedges in place for oil or natural gas liquids beyond 2016; however, we have a portion of our anticipated natural gas volumes hedged in 2017.

Due to the sharp decline in commodity prices since mid-2014, we anticipate that our operating cash flows in 2016 will be less than in 2015. Further, if our exploration, development and production activities result in less cash flows than anticipated, we may seek additional sources of capital, including through additional borrowings under our Credit Agreement, additional credit arrangements, the sale of midstream or other assets or acreage or entering into one or more joint ventures, none of which may be available. In addition to future borrowings under our Credit Agreement, we may also seek to raise additional funds by issuing debt securities or selling shares of our common stock or securities convertible or exercisable into our common stock

Table of Contents

(including debt securities or other preferential securities) in the public markets or otherwise. Any such sales of equity or convertible securities would dilute the ownership interest of our existing shareholders. There is no guarantee that we would be able to sell such debt or equity securities on terms acceptable to us. It is also possible that, to the extent we are not able to obtain additional sources of capital, we may modify our planned capital expenditure budget for 2016 accordingly to further reduce our capital spending and rate of growth or enter into one or more joint ventures or other alternative financings. Exploration and development activities are subject to a number of risks and uncertainties that could impact our ability to sufficiently increase our reserves, cash flows from operations and the borrowing base under our Credit Agreement. See "Risk Factors — Our Exploration, Development and Exploitation Projects Require Substantial Capital Expenditures That May Exceed Our Cash Flows from Operations and Potential Borrowings, and We May Be Unable to Obtain Needed Capital on Satisfactory Terms, Which Could Adversely Affect Our Future Growth," "Risk Factors — Drilling for and Producing Oil and Natural Gas Are Highly Speculative and Involve a High Degree of Operational and Financial Risk, with Many Uncertainties That Could Adversely Affect Our Business" and "Risk Factors — Our Identified Drilling Locations Are Scheduled over Several Years, Making Them Susceptible to Uncertainties That Could Materially Alter the Occurrence or Timing of Their Drilling."

Expenditures for the acquisition, exploration and development of oil and natural gas properties are the primary use of our capital resources. We anticipate investing approximately $325.0 million in capital for acquisition, exploration and development and midstream activities in 2016 as follows.

	Amount (in millions)
Exploration and development drilling and completion costs, including production facilities and infrastructure	$260.0
Midstream activities	40.0
Leasehold acquisition and 2-D and 3-D seismic data	25.0
Total	$325.0

Our 2016 capital expenditures may be adjusted as business conditions warrant, as evidenced by the substantial reduction in our 2016 capital expenditure budget, as compared to our 2015 capital spending, in response to the sharp decline in oil and natural gas prices since mid-2014. The amount, timing and allocation of our capital expenditures is largely discretionary and within our control. If oil or natural gas prices decline further or costs increase significantly, we could defer a portion of our anticipated capital expenditures until later periods to conserve cash or to focus on those projects that we believe have the highest expected returns and potential to generate near-term cash flows. For example, if oil prices drop and remain below $30.00 per Bbl, we have the flexibility to reduce the number of rigs we are operating from three rigs to two rigs either for a short time or for the remainder of 2016, beginning as early as the second quarter of 2016. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling, completion and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in our exploration and development activities, contractual obligations, drilling plans for properties we do not operate and other factors both within and outside our control.

Our cash flows for the years ended December 31, 2015, 2014 and 2013 are presented below.

	Year Ended December 31,		
	2015	2014	2013
(In thousands)			
Net cash provided by operating activities	$208,535	$251,481	$179,470
Net cash used in investing activities	(425,154)	(570,531)	(366,939)
Net cash provided by financing activities	224,944	321,170	191,661
Net change in cash	$8,325	$2,120	$4,192

Cash Flows Provided by Operating Activities

Net cash provided by operating activities decreased by $42.9 million to $208.5 million for the year ended December 31, 2015, as compared to net cash provided by operating activities of $251.5 million for the year ended December 31,

2014. Excluding changes in operating assets and liabilities, net cash provided by operating activities decreased to $199.6 million for the year ended December 31, 2015 from $257.5 million for the year ended December 31, 2014. This decrease is primarily attributable to the decrease in oil revenues from 2014 to 2015, resulting from a significantly lower weighted average oil price realized for the year ended December 31, 2015 of $45.27 per Bbl, as compared to $87.37 per Bbl realized for the year ended December 31, 2014. This decrease was partially offset by the increase of approximately 35% in our oil production to approximately 4.5 million Bbl from just over 3.3 million Bbl during the respective periods. Changes in our operating assets and liabilities between December 31, 2014 and December 31, 2015 also resulted in a net increase of approximately $15.0 million in net cash provided by operating activities for the year ended December 31, 2015, as compared to the year ended December 31, 2014.

Net cash provided by operating activities increased by $72.0 million to $251.5 million for the year ended December 31, 2014, as compared to net cash provided by operating activities of $179.5 million for the year ended December 31, 2013. Excluding changes in operating assets and liabilities, net cash provided by operating activities increased significantly to $257.5 million for the year ended December 31, 2014 from $185.7 million for the year ended December 31, 2013. This increase is primarily attributable to the increase of approximately 56% in our oil production to just over 3.3 million Bbl from approximately 2.1 million Bbl during the respective periods. Changes in our operating assets and liabilities between December 31, 2014 and December 31, 2013 also resulted in a net increase of approximately $0.2 million in net cash provided by operating activities for the year ended December 31, 2014, as compared to the year ended December 31, 2013.

Our operating cash flows are sensitive to a number of variables, including changes in our production and the volatility of oil and natural gas prices between reporting periods. Regional and worldwide economic activity, the actions of OPEC, weather, infrastructure capacity to reach markets and other variable factors significantly impact the prices of oil and natural gas. These factors are beyond our control and are difficult to predict. We use commodity derivative financial instruments to mitigate our exposure to fluctuations in oil, natural gas and natural gas liquids prices. In addition, we attempt to avoid long-term service agreements in order to minimize ongoing future commitments. For additional information on the impact of changing prices on our financial condition, see “Quantitative and Qualitative Disclosures About Market Risk” below. See also “Risk Factors — Our Success Is Dependent on the Prices of Oil and Natural Gas. Low Oil or Natural Gas Prices and the Substantial Volatility in These Prices May Adversely Affect Our Financial Condition and Our Ability to Meet Our Capital Expenditure Requirements and Financial Obligations.”

Cash Flows Used in Investing Activities

Net cash used in investing activities decreased by $145.4 million to $425.2 million for the year ended December 31, 2015 from $570.5 million for the year ended December 31, 2014. This decrease in net cash used in investing activities included (i) a decrease of $128.1 million in our oil and natural gas properties capital expenditures for the year ended December 31, 2015, as compared to the year ended December 31, 2014, (ii) proceeds from the sale of the Loving County System to EnLink of $139.8 million, (iii) an increase of approximately $55.3 million in expenditures for other property and equipment, which includes the Processing Plant and salt water disposal facilities we constructed in Loving County, Texas as well as initial costs associated with a natural gas processing plant we are constructing in Eddy County, New Mexico, and new pipeline infrastructure, (iv) cash used in the HEYCO Merger of $24.0 million and (v) an increase in our restricted cash of $43.1 million attributable to the escrow account associated with potential like-kind-exchange transactions in connection with the sale of the Loving County System to EnLink. Cash used for oil and natural gas properties capital expenditures for the year ended December 31, 2015 was primarily attributable to our operated and non-operated drilling and completion activities in the Delaware Basin, as well as to our operated and non-operated drilling activities in the Eagle Ford shale play and certain non-operated drilling activities in the Haynesville shale.

Net cash used in investing activities increased by $203.6 million to $570.5 million for the year ended December 31, 2014 from $366.9 million for the year ended December 31, 2013. This increase in net cash used in investing activities reflected an increase of $197.7 million in our oil and natural gas properties capital expenditures for the year ended December 31, 2014, as compared to the year ended December 31, 2013, and an increase of approximately $5.2 million in expenditures for other property and equipment, which included new pipeline infrastructure associated with our properties in the Eagle Ford shale, but also reflects initial costs associated with construction of the Processing Plant and a salt water disposal facility in Loving County, Texas. Cash used for oil and natural gas properties capital expenditures for the year ended December 31, 2014 was primarily attributable to our operated and non-operated drilling and completion activities in the Eagle Ford shale play, as well as to our initial operated drilling activities in the Delaware Basin and certain non-operated drilling activities in Haynesville shale. We also used a portion of this cash to acquire approximately 29,300 gross (21,800 net) additional acres in the Delaware Basin in 2014, along with approximately 3,200 gross (3,000 net) acres in the Eagle Ford shale.

Cash Flows Provided by Financing Activities

Net cash provided by financing activities was $224.9 million for the year ended December 31, 2015, as compared to net cash provided by financing activities of $321.2 million for the year ended December 31, 2014. The net cash provided by financing activities for the year ended December 31, 2015 was primarily attributable to the total proceeds of our public equity offering of $188.7 million, the total proceeds of our Notes issuance of $400.0 million, borrowings under our Credit Agreement of $125.0 million and capital contributed from the non-controlling interest owners in our less-than-wholly-owned subsidiaries of $0.6 million, offset by the costs of the public equity offering of $1.2 million, the costs of the Notes issuance of $9.6 million, the repayment of $477.0 million in borrowings under our Credit Agreement during the period and the payment of $1.6 million in taxes related to net share settlement of stock-based compensation.

Table of Contents

Net cash provided by financing activities was $321.2 million for the year ended December 31, 2014, as compared to net cash provided by financing activities of $191.7 million for the year ended December 31, 2013. The net cash provided by financing activities for the year ended December 31, 2014 was primarily attributable to the total proceeds from our May 2014 public equity offering of $181.9 million and borrowings of $320.0 million under our Credit Agreement during the period, offset by the costs of the offering of $0.6 million incurred during the period and by the repayment of $180.0 million in borrowings under our Credit Agreement during the period.

Net cash provided by financing activities was $191.7 million for the year ended December 31, 2013. The net cash provided by financing activities for the year ended December 31, 2013 was principally due to the total proceeds from our September 2013 public equity offering of $149.1 million and total borrowings of $180.0 million under our Credit Agreement during the period, offset by the costs of the offering of $7.4 million incurred during the period and by the repayment of $130.0 million in borrowings under our Credit Agreement during the period.

See Note 6 to the consolidated financial statements in this Annual Report on Form 10-K for a summary of our debt, including our Credit Agreement and the Notes.

Off-Balance Sheet Arrangements

From time-to-time, the Company enters into off-balance sheet arrangements and transactions that can give rise to material off-balance sheet obligations of the Company. As of December 31, 2015, the material off-balance sheet arrangements and transactions that the Company has entered into include (i) operating lease agreements, (ii) non-operated drilling commitments, (iii) termination obligations under drilling rig contracts, (iv) firm transportation and fractionation commitments, (v) agreements to construct facilities and (vi) contractual obligations for which the ultimate settlement amounts are not fixed and determinable, such as derivative contracts that are sensitive to future changes in commodity prices or interest rates, gathering, treating, fractionation and transportation commitments on uncertain volumes of future throughput, open delivery commitments and indemnification obligations following certain divestitures. Other than the off-balance sheet arrangements described above, the Company has no transactions, arrangements or other relationships with unconsolidated entities or other persons that are reasonably likely to materially affect the Company's liquidity or availability of or requirements for capital resources. See Note 13 to the consolidated financial statements in this Annual Report on Form 10-K for more information regarding the Company's off-balance sheet arrangements. Such information is incorporated herein by reference.

Obligations and Commitments

We had the following material contractual obligations and commitments at December 31, 2015.

	Payments Due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
(In thousands)					
Contractual Obligations:					
Revolving credit borrowings and term loan, including letters of credit (1)	$600	$—	$600	$—	$—
Senior unsecured notes (2)	400,000	—	—	—	400,000
Office leases	27,062	2,017	4,920	5,130	14,995
Non-operated drilling commitments (3)	5,652	5,652	—	—	—
Drilling rig contracts (4)	43,450	23,156	20,294	—	—
Asset retirement obligations	15,420	254	1,136	2,563	11,467
Natural gas processing and transportation agreements (5)	12,618	11,423	1,195	—	—
Gas plant engineering, procurement, construction and installation contract (6)	21,500	21,500	—	—	—
Total contractual cash obligations	$526,302	$64,002	$28,145	$7,693	$426,462

(1) At December 31, 2015, we had no borrowings outstanding under our Credit Agreement and approximately $0.6 million in outstanding letters of credit issued pursuant to the Credit Agreement. These borrowings mature in

October 2020.

(2) The amounts included in the table above represent principal maturities only.

(3) At December 31, 2015, we had outstanding commitments to participate in the drilling and completion of various non-operated wells. Our working interests in these wells are typically small, and certain of these wells were in progress at December 31, 2015. If all of these wells are drilled and completed, we will have minimum outstanding aggregate commitments for our participation in these wells of approximately $5.7 million at December 31, 2015, which we expect to incur within the next year.

(4) We do not own or operate our own drilling rigs, but instead we enter into contracts with third parties for such drilling rigs. These contracts establish daily rates for the drilling rigs and the term of our commitments for the drilling services to be provided, which have typically been for one year or less, although in 2014, we entered into longer-term contracts in order to secure new drilling rigs equipped with the latest technology in plays that were

experiencing heavy demand for drilling rigs. Should we elect to terminate a contract and if the drilling contractor were unable to secure replacement work for the contracted drilling rigs or if the drilling contractor were unable to secure replacement work for the contracted drilling rigs at the same daily rates being charged to us prior to the end of their respective contract terms, we would incur termination obligations. Our maximum outstanding aggregate termination obligations under our drilling rig contracts were approximately $43.5 million at December 31, 2015.

(5) Effective September 1, 2012, we entered into a firm five-year natural gas processing and transportation agreement for a significant portion of our operated natural gas production in South Texas. The undiscounted minimum commitments under this agreement total approximately $3.0 million at December 31, 2015. Effective October 1, 2015, we entered into a 15-year fixed-fee natural gas gathering and processing agreement for a significant portion of our operated natural gas production in Loving County, Texas. The undiscounted minimum initial commitments under this agreement total approximately $216.1 million at December 31, 2015; however, at the end of each year of the agreement, we can elect to have the previous year's actual transportation and processing volumes be the new minimum commitment for each of the remaining years under the contract. As such, we have the ability to unilaterally reduce the transportation and processing commitment if our production in the Loving County area is less than our currently projected production. In addition, if we elect to reduce the transportation and processing commitment in any year, we have the ability to elect to increase the committed volumes in any future year to the originally agreed transportation and processing commitment. If we do not meet the volume commitment for transportation and processing at the facility in a contract year, we will be required to pay a deficiency fee per MMBtu of natural gas deficiency. If we did not use any of our commitment and elected to reduce our future years' commitment to zero, the deficiency payment required to be paid in 2016 under the contract would be approximately $9.6 million at December 31, 2015 and no further deficiency payments would be required in future years.

(6) We entered into an agreement with a third party for the engineering, procurement, construction and installation of a natural gas processing plant in the Rustler Breaks prospect area in Eddy County, New Mexico in 2015. This plant is expected to process a portion of our natural gas produced from certain of our wells in the Delaware Basin, as well as third-party natural gas. The plant is scheduled to be completed and placed in service in the third quarter of 2016.

General Outlook and Trends

Our business success and financial results are dependent on many factors beyond our control, such as economic, political and regulatory developments, as well as competition from other sources of energy. Commodity price volatility, in particular, is a significant risk to our business and results of operations. Commodity prices are affected by changes in market supply and demand, which are impacted by overall economic activity, the actions of OPEC, weather, pipeline capacity constraints, inventory storage levels, oil and natural gas price differentials and other factors. Historically, the markets for oil, natural gas and natural gas liquids have been volatile and these markets will likely continue to be volatile in the future. Prices for oil, natural gas and natural gas liquids affect the cash flows available to us for capital expenditures and our ability to borrow and raise additional capital. Further declines in oil, natural gas or natural gas liquids prices would not only further reduce our revenues, but could also reduce the amount of oil, natural gas and/or natural gas liquids that we can produce economically, and as a result, could have an adverse effect on our financial condition, results of operations, cash flows and reserves. From time to time, we use derivative financial instruments to mitigate our exposure to commodity price risk associated with oil, natural gas and natural gas liquids prices. Even so, decisions as to whether, at what price and what production volumes to hedge are difficult and depend on market conditions and our forecast of future production and oil, natural gas and natural gas liquids prices, and we may not always employ the optimal hedging strategy. This, in turn, may affect the liquidity that can be accessed through the borrowing base under our Credit Agreement and through the capital markets. See "Risk Factors — Our Success Is Dependent on the Prices of Oil and Natural Gas. Low Oil or Natural Gas Prices and the Substantial Volatility in These Prices May Adversely Affect Our Financial Condition and Our Ability to Meet Our Capital

Expenditure Requirements and Financial Obligations."

Throughout 2015, oil and natural gas prices continued to decline sharply from their most recent highs in 2014. Oil prices have decreased 68% from $107.26 per Bbl in mid-June to $34.73 per Bbl in late December 2015, and natural gas prices have decreased 71% from $6.15 per MMBtu in mid-February 2014 to $1.76 per MMBtu in mid-December 2015. These sharp declines in oil and natural gas prices impacted our revenues, profitability and cash flows in 2015, as compared to 2014, and further declines in the price of oil and natural gas could have an adverse impact on our borrowing capacity, ability to obtain additional capital, revenues, profitability and cash flows. We are uncertain when, or if, oil and natural gas prices may rise from their current levels, and in fact, oil and natural gas prices may decrease further in future periods.

For the year ended December 31, 2015, oil prices averaged $48.79 per Bbl, ranging from a high of $61.43 per Bbl in mid-June to a low of $34.73 per Bbl in late December, based upon the NYMEX West Texas Intermediate oil futures contract price for the earliest delivery date. We realized a weighted average oil price of $45.27 per Bbl ($59.13 per Bbl including realized gains from oil derivatives) for our oil production for the year ended December 31, 2015, as compared to $87.37 per Bbl ($88.94 per Bbl including realized gains from oil derivatives) for the year ended December 31, 2014. At February 25, 2016, the NYMEX West Texas Intermediate oil futures contract for the earliest delivery date had declined further, closing at $33.07 per Bbl, as compared to $50.99 per Bbl at February 25, 2015.

For the year ended December 31, 2015, natural gas prices averaged $2.63 per MMBtu, ranging from a high of approximately $3.23 per MMBtu in mid-January to a low of approximately $1.76 per MMBtu in mid-December, based upon the NYMEX Henry Hub natural gas futures contract price for the earliest delivery date. We realized a weighted average natural gas price of $2.71 per Mcf ($3.24 per Mcf including realized gains from natural gas and NGL derivatives) for our natural gas production for the year ended December 31, 2015, as compared to $5.08 per Mcf ($5.06 per Mcf including realized losses from natural gas and NGL derivatives) for the year ended December 31, 2014. At February 25, 2016, the NYMEX Henry Hub natural gas futures contract for the earliest delivery date had declined further, closing at $1.71 per MMBtu, as compared to $2.89 per MMBtu at February 25, 2015.

In response to the continued decline in oil and natural gas prices experienced throughout 2015 and into early 2016, we have reduced our 2016 estimated capital expenditure budget to $325.0 million, as compared to actual capital expenditures of $482.1 million (excluding capital expenditures associated with the HEYCO Merger) for the year ended December 31, 2015. We plan to operate three contracted drilling rigs in the Delaware Basin throughout 2016, although should oil prices drop and remain below $30.00 per Bbl, we have the flexibility to reduce the number of rigs we are operating from three rigs to two rigs, either for a short time or for the remainder of 2016, beginning as early as the second quarter of 2016. This could reduce our estimated 2016 capital expenditures by approximately $50.0 million. Our 2016 estimated capital expenditure budget of $325.0 million (assuming a three-rig program) consists of approximately $260.0 million for drilling, completions, facilities and infrastructure, $40.0 million principally for the completion of new midstream facilities in the Delaware Basin to support our operations there and $25.0 million for land acquisitions and seismic data, primarily in the Delaware Basin. Development of our Delaware Basin assets will be the primary driver of our projected growth in 2016. Approximately $315.0 million, or 97%, of our 2016 estimated capital expenditures will be allocated to the further delineation and development of our growing leasehold position in the Delaware Basin. Our 2016 Delaware Basin drilling program will focus on the development of the Wolf and Rustler Breaks prospect areas and the further delineation and development of the Ranger and Arrowhead prospect areas. The $40.0 million in midstream capital expenditures is expected to primarily fund completion of the construction and installation of a cryogenic natural gas processing plant with approximately 60 MMcf per day of inlet capacity and a natural gas gathering system in the Rustler Breaks prospect area in Eddy County, New Mexico. This plant is expected to be operational by the third quarter of 2016.

We do not plan to drill any operated Eagle Ford shale wells in South Texas or Haynesville shale natural gas wells in Northwest Louisiana during 2016. Approximately $5.6 million, or 2%, of our 2016 estimated capital expenditures will be allocated to the Eagle Ford shale to allow for the installation of pumping units on certain properties and for lease extensions and acquisitions, if desired, and approximately $4.4 million, or just over 1%, of our 2016 estimated capital expenditures will be allocated to participation in non-operated Haynesville shale wells. Approximately 92% of our Eagle Ford acreage and essentially all of our Haynesville and Cotton Valley acreage was either held by production at December 31, 2015 or not burdened by lease expirations before 2017.

Coincident with the recent declines in commodity prices, we have experienced price reductions from our service providers for many of the products and services we use in our drilling, completion and production operations. If oil and natural gas prices remain at their current levels for a longer period of time or should they decline further, we would anticipate receiving additional price reductions for drilling, completion and production products and services, although we can provide no assurances that these price reductions will occur or of their eventual magnitude.

Like other oil and natural gas producing companies, our properties are subject to natural production declines. By their nature, our oil and natural gas wells will experience rapid initial production declines. We attempt to overcome these production declines by drilling to develop and identify additional reserves, by exploring for new sources of reserves and, at times, by acquisitions. During times of severe oil, natural gas and natural gas liquids price declines, however, drilling additional oil or natural gas wells may not be economical, and we may find it necessary to reduce capital expenditures and curtail drilling operations in order to preserve liquidity. A material reduction in capital expenditures and drilling activities could materially impact our production volumes, revenues, reserves, cash flows and our availability under our Credit Agreement. See “Risk Factors — Our Exploration, Development and Exploitation Projects Require Substantial Capital Expenditures That May Exceed Our Cash Flows from Operations and Potential Borrowings, and We May Be Unable to Obtain Needed Capital on Satisfactory Terms, Which Could Adversely Affect Our Future Growth.”

We strive to focus our efforts on increasing oil and natural gas reserves and production while controlling costs at a level that is appropriate for long-term operations. Our ability to find and develop sufficient quantities of oil and natural gas reserves at economical costs is critical to our long-term success. Future finding and development costs are subject to changes in the costs of acquiring, drilling and completing our prospects.

Critical Accounting Policies and Estimates

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and assumptions that affect the reported amounts of certain assets, liabilities, revenues and expenses during each reporting period. We believe that our estimates and assumptions are reasonable and reliable, and believe that the actual results will not differ significantly from those reported; however, such estimates and assumptions are subject to a number of risks and uncertainties, and such risks and uncertainties could cause the actual results to differ materially from our estimates. We consider the following to be our most critical accounting policies and estimates involving significant judgment or estimates by our management. See Note 2 to the consolidated financial statements in this Annual Report on Form 10-K for further details on our accounting policies at December 31, 2015. Such information is incorporated herein by reference.

Oil and Natural Gas Properties

We use the full-cost method of accounting for our investments in oil and natural gas properties. Under this method of accounting, all costs associated with the acquisition, exploration and development of oil and natural gas properties and reserves, including unproved and unevaluated property costs, are capitalized as incurred and accumulated in a single cost center representing our activities, which are undertaken exclusively in the United States. Such costs include lease acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling both productive and non-productive wells, capitalized interest on qualifying projects and general and administrative expenses directly related to acquisition, exploration and development activities, but do not include any costs related to production, selling or general corporate administrative activities.

Capitalized costs of oil and natural gas properties are amortized using the unit-of-production method based upon production and estimates of proved reserves quantities. Unproved and unevaluated property costs are excluded from the amortization base used to determine depletion. Unproved and unevaluated properties are assessed for possible impairment on a periodic basis based upon changes in operating or economic conditions. This assessment includes consideration of the following factors, among others: the assignment of proved reserves, geological and geophysical evaluations, intent to drill, remaining lease term and drilling activity and results. Upon impairment, the costs of the unproved and unevaluated properties are immediately included in the amortization base. Exploratory dry holes are included in the amortization base immediately upon the determination that the well is not productive.

Sales of oil and natural gas properties are accounted for as adjustments to net capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between net capitalized costs and proved reserves of oil and natural gas. All costs related to production activities and maintenance and repairs are expensed as incurred. Significant workovers that increase the properties' reserves are capitalized.

Ceiling Test

The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized costs less related deferred income taxes or the cost center "ceiling." The cost center ceiling is defined as the sum of:

(a) the present value, discounted at 10%, of future net revenues of proved oil and natural gas reserves, reduced by the estimated costs of developing these reserves, plus

(b) unproved and unevaluated property costs not being amortized, plus

(c) the lower of cost or estimated fair value of unproved and unevaluated properties included in the costs being amortized, if any, less

(d) income tax effects related to the properties involved.

Any excess of our net capitalized costs above the cost center ceiling as described above is charged to operations as a full-cost ceiling impairment. The fair value of our derivative instruments is not included in the ceiling test computation as we do not designate these instruments as hedge instruments for accounting purposes.

The estimated present value of after-tax future net cash flows from proved oil and natural gas reserves is highly dependent upon the quantities of proved reserves, the estimation of which requires substantial judgment. The associated commodity prices and the applicable discount rate used in these estimates are in accordance with guidelines established by the SEC. Under these guidelines, oil and natural gas reserves are estimated using then-current operating and economic conditions, with no provision for price and cost escalations in future periods except by contractual arrangements. Future net revenues are calculated using prices that represent the arithmetic averages of the first-day-of-the-month oil and natural gas prices for the previous 12-month period and a 10% discount factor is used to determine the present value of future net revenues.

Because the cost center ceiling calculation is based on the average of historical prices, which may or may not be representative of future prices, and requires a 10% discount factor, the resulting estimated value may not be indicative of the fair market value of our properties. Any impairment related to the excess of our net capitalized costs above the resulting cost center ceiling should not be viewed as an absolute indicator of a reduction in the ultimate value of the related reserves.

Derivative Financial Instruments

From time to time, we use derivative financial instruments to mitigate our exposure to commodity price risk associated with oil, natural gas and natural gas liquids prices. These instruments typically consist of put and call options in the form of costless (or zero-cost) collars and swap contracts. Costless collars provide us with downside price protection through the purchase of a put option which is financed through the sale of a call option. Because the call option proceeds are used to offset the cost of the put option, these arrangements are initially “costless” to us. In the case of a costless collar, the put option and the call option have different fixed price components. In a swap contract, a floating price is exchanged for a fixed price over a specified period, providing downside price protection.

Prior to settlement, our derivative financial instruments are recorded on the balance sheet as either an asset or a liability measured at fair value. We have elected not to apply hedge accounting for our existing derivative financial instruments, and as a result, we recognize the change in derivative fair value between reporting periods currently in our consolidated statements of operations. Such changes in fair value are reported under Revenues as “Unrealized gain (loss) on derivatives.” Changes in the fair value of these open derivative financial instruments can have a significant impact on our reported results from period to period but do not impact our cash flow from operations, liquidity or capital resources. The fair value of our derivative financial instruments is determined using industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value of money and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Realized gains and realized losses from the settlement of derivative financial instruments do have a direct impact on our cash flow from operations and liquidity. The impact of these settlements is also reported under Revenues as “Realized gain (loss) on derivatives.”

Revenue Recognition

We follow the sales method of accounting for our oil, natural gas and natural gas liquids revenue, whereby we recognize revenue, net of royalties, on all oil, natural gas and natural gas liquids sold to purchasers regardless of whether the sales are proportionate to our ownership in the property. Under this method, revenue is recognized at the time the oil, natural gas and natural gas liquids are produced and sold, and we accrue for revenue earned but not yet received.

Stock-Based Compensation

We account for stock-based compensation in accordance with ASC 718. During 2015, 2014, 2013 and 2012 all stock option awards were granted under our 2012 Long-Term Incentive Plan, or the Amended and Restated 2012 Long-Term Incentive Plan for awards granted after June 10, 2015, and were equity instruments. We did not grant any stock option awards in 2011. Prior to 2011, all stock option awards were granted under our 2003 Stock and Incentive Plan, and since November 22, 2010, these awards have been accounted for as liability instruments. We used the fair value method to measure and recognize the liability associated with our outstanding liability-based stock options and to measure and recognize the equity associated with our equity-based stock options. Stock options typically vest over three or four years, and the associated compensation expense is recognized on a straight-line basis over the vesting period. Restricted stock and restricted stock units typically vest over a period of one to four years, and compensation expense is recognized on a straight line basis over the vesting period. As our shares were not publicly traded prior to February 2, 2012, we estimated the future volatility of our stock using the historical volatility of the common stock of a group of companies we consider to be a representative peer group. Management believes that these average historical volatility rates are currently the best available indicator of future volatility.

We have adopted the “simplified method” as outlined in Staff Accounting Bulletin Topic 14 for estimating the expected term of awards. The risk free interest rate is the rate for constant yield U.S. Treasury securities with a term to maturity that is consistent with the expected term of the award.

Assumptions are reviewed each time new equity-based option awards are granted and quarterly for outstanding liability-based option awards. The assumptions used may be impacted by actual fluctuations in our stock price, movements in market interest rates and option terms. The use of different assumptions produces a different fair value for equity-based option awards and outstanding liability-based option awards and can significantly impact the amount of stock compensation expense recognized in our consolidated statement of operations. We use the Black Scholes Merton model to determine the fair value of service-based option awards and the Monte Carlo method to determine the fair value of option awards that contain a market condition. The fair value of restricted stock and restricted stock unit awards are recognized based on the fair value of our stock on the date of the grant. See Note 8 to the consolidated financial statements in this Annual Report on Form 10-K for further details on our stock-based compensation at

December 31, 2015. Such information is incorporated herein by reference.

Income Taxes

We account for income taxes using the asset and liability approach for financial accounting and reporting. The amount of income taxes recorded requires interpretations of complex rules and regulations of federal and state taxing authorities. We have recognized deferred tax assets and liabilities for temporary differences, operating losses and tax carryforwards. We evaluate the probability of realizing the future benefits of our deferred tax assets and provide a valuation allowance for the portion of any deferred tax assets where the likelihood of realizing an income tax benefit in the future does not meet the more likely than not criteria for recognition.

Table of Contents

We account for uncertainty in income taxes by recognizing the financial statement benefit of a tax position only after determining that the relevant tax authority would more likely than not sustain the position following an audit. For tax positions meeting the more likely than not threshold, the amount recognized in the financial statements is the benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority.

Oil and Natural Gas Reserves Quantities and Standardized Measure of Future Net Revenue

Our engineers and technical staff prepare our estimates of oil and natural gas reserves and associated future net revenues. While the applicable rules allow us to disclose proved, probable and possible reserves, we have elected to present only proved reserves in this Annual Report on Form 10-K. The applicable rules define proved reserves as the quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible — from a given date forward, from known reservoirs and under existing economic conditions, operating methods and government regulations — prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

Our engineers and technical staff must make many subjective assumptions based on their professional judgment in developing reserves estimates. Reserves estimates are updated quarterly and consider recent production levels and other technical information about each well. Estimating oil and natural gas reserves is complex and is inexact because of the numerous uncertainties inherent in the process. The process relies on interpretations of available geological, geophysical, petrophysical, engineering and production data. The extent, quality and reliability of both the data and the associated interpretations can vary. The process also requires certain economic assumptions, including, but not limited to, oil and natural gas prices, development expenditures, operating expenses, capital expenditures and taxes. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas will most likely vary from our estimates. Accordingly, reserves estimates are generally different from the quantities of oil and natural gas that are ultimately recovered. Any significant variance could materially and adversely affect our future reserves estimates, financial condition, results of operations and cash flows. We cannot predict the amounts or timing of future reserves revisions. If such revisions are significant, they could significantly affect future amortization of capitalized costs and result in an impairment of assets that may be material. See “Risk Factors — Our Oil and Natural Gas Reserves Are Estimated and May Not Reflect the Actual Volumes of Oil and Natural Gas We Will Recover, and Significant Inaccuracies in These Reserves Estimates or Underlying Assumptions Will Materially Affect the Quantities and Present Value of Our Reserves.”

Recent Accounting Pronouncements

Recognition and Measurement of Financial Assets and Financial Liabilities. In January 2016, the FASB issued Accounting Standards Update, or ASU, 2016-01, Recognition and Measurement of Financial Assets and Financial Liabilities, which changes certain guidance related to the recognition, measurement, presentation and disclosure of financial instruments. This update is effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early adoption is not permitted for the majority of the update, but is permitted for two of its provisions. We are currently evaluating the new guidance and have not determined the impact this standard may have on our consolidated financial statements.

Revenue from Contracts with Customers. In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606), which specifies how and when to recognize revenue. This standard requires expanded disclosures surrounding revenue recognition and is intended to improve, and converge with international standards, the financial reporting requirements for revenue from contracts with customers. In August 2015, the FASB issued ASU 2015-14, which defers the effective date of ASU 2014-09 for one year to annual reports beginning after December 15, 2017. We are currently evaluating the impact, if any, of the adoption of this ASU on our consolidated financial statements.

Interest - Imputation of Interest. In April 2015, the FASB issued ASU 2015-03, Interest - Imputation of Interest (Subtopic 935-30): Simplifying the Presentation of Debt Issuance Costs, which requires companies that have historically presented debt issuance costs as an asset to present those costs as a direct deduction from the carrying amount of the underlying debt liability. The guidance requires retrospective application in financial statements issued for fiscal years and interim periods beginning after December 15, 2015 but early adoption is permitted. We adopted this ASU effective June 30, 2015. See Note 2 to the consolidated financial statements in this Annual Report on Form 10-K for a description of the impact of the adoption of this standard on our consolidated financial statements.

Income Taxes. In November 2015, the FASB issued ASU 2015-17, Income Taxes (Topic 740), which requires deferred income tax liabilities and assets to be classified as noncurrent in a classified statement of financial position. The standard permitted either prospective or retrospective application. We elected to apply the standard retrospectively. We adopted ASU 2015-17, Income Taxes (Topic 740), effective December 31, 2015. See Note 2 to the consolidated financial statements in this

Annual Report on Form 10-K for a description of the impact of the adoption of this standard on our consolidated financial statements.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk.

We are exposed to a variety of market risks including commodity price risk, interest rate risk and counterparty and customer risk. We address these risks through a program of risk management including the use of derivative financial instruments, but we do not enter into derivative financial instruments for trading purposes.

Commodity price exposure. We are exposed to market risk as the prices of oil, natural gas and natural gas liquids fluctuate as a result of changes in supply and demand and other factors. To partially reduce price risk caused by these market fluctuations, we have entered into derivative financial instruments in the past and expect to enter into derivative financial instruments in the future to cover a significant portion of our future anticipated production.

We typically use costless (or zero-cost) collars and/or swap contracts to manage risks related to changes in oil, natural gas and natural gas liquids prices. Costless collars provide us with downside price protection through the purchase of a put option which is financed through the sale of a call option. Because the call option proceeds are used to offset the cost of the put option, these arrangements are initially “costless” to us. In the case of a costless collar, the put option and the call option have different fixed price components. In a swap contract, a floating price is exchanged for a fixed price over a specified period, providing downside price protection.

We record all derivative financial instruments at fair value. The fair value of our derivative financial instruments is determined using purchase and sale information available for similarly traded securities. At December 31, 2015, The Bank of Nova Scotia and BMO Harris Financing (Bank of Montreal) (or affiliates thereof) were the counterparties for all of our derivative instruments. We have considered the credit standing of the counterparties in determining the fair value of our derivative financial instruments.

At December 31, 2015, we have entered into various costless collar contracts to mitigate our exposure to fluctuations in oil and natural gas prices, each with an established price floor and ceiling. For each calculation period, the specified price for determining the realized gain or loss to us pursuant to any oil contract is the arithmetic average of the settlement prices for the NYMEX West Texas Intermediate oil futures contract for the first nearby month corresponding to the calculation period’s calendar month, and for any natural gas contract is the settlement price for the NYMEX Henry Hub natural gas futures contract for the delivery month corresponding to the calculation period’s calendar month for the settlement date of that contract period.

When the settlement price is below the price floor established by one or more of these collars, we receive from our counterparty an amount equal to the difference between the settlement price and the price floor multiplied by the contract oil or natural gas volume. When the settlement price is above the price ceiling established by one or more of these collars, we pay our counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract oil or natural gas volume.

See Note 11 to the consolidated financial statements in this Annual Report on Form 10-K for a summary of our open derivative financial instruments at December 31, 2015. Such information is incorporated herein by reference.

Effect of Recent Derivatives Legislation. On July 21, 2010, President Obama signed into law the Dodd-Frank Wall Street Reform and Consumer Protection Act, or the Dodd-Frank Act, which is intended to modernize and protect the integrity of the U.S. financial system. The Dodd-Frank Act, among other things, establishes federal oversight and regulation of certain derivative products including commodity hedges of the type we use. The Dodd-Frank Act requires the Commodity Futures Trading Commission, or CFTC, and the SEC to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized certain of these regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished. Based upon the limited assessments we are able to make with respect to the Dodd-Frank Act, there is the possibility that the Dodd-Frank Act could have a substantial and adverse impact on our ability to enter into and maintain these commodity hedges. In particular, the Dodd-Frank Act could result in the implementation of position limits and additional regulatory requirements on our derivative arrangements, which could include new margin, reporting and clearing requirements. In addition, this legislation could have a substantial impact on our counterparties and may increase the cost of our derivative arrangements in the future. See “Risk Factors — The Derivatives Legislation Adopted by Congress Could Have an Adverse Impact on Our Ability to Hedge Risks Associated with Our Business.”

Interest rate risk. We do not and have not used interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense on existing debt since we borrowed under our Credit Agreement for the first time in December 2010. At December 31, 2015 we had no outstanding borrowings under our Credit Agreement and $400.0 million in Notes outstanding at an interest rate of 6.875% per annum. If we incur additional indebtedness in the future and at higher interest rates, we may use interest rate derivatives. Interest rate derivatives would be used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Table of Contents

Counterparty and customer credit risk. Joint interest receivables arise from billing entities which own partial interests in the wells we operate. These entities participate in our wells primarily based on their ownership in leases on which we wish to drill. We have limited ability to control participation in our wells. We are also subject to credit risk due to concentration of our oil and natural gas receivables with several significant customers. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial condition, results of operations and cash flows. In addition, our oil, natural gas and natural gas liquids derivative arrangements expose us to credit risk in the event of nonperformance by our counterparties.

While we do not require our customers to post collateral and we do not have a formal process in place to evaluate and assess the credit standing of our significant customers for oil and natural gas receivables and the counterparties on our derivative instruments, we do evaluate the credit standing of such counterparties as we deem appropriate under the circumstances. This evaluation requires us to conduct the due diligence necessary to determine credit terms and credit limits, which may include (i) reviewing a counterparty's credit rating, latest financial information and, in the case of a customer with which we have receivables, its historical payment record and the financial ability of its parent company to make payment if the customer cannot and (ii) undertaking the due diligence necessary to determine credit terms and credit limits. The counterparties on our derivative financial instruments in place at February 25, 2016 were The Bank of Nova Scotia, SunTrust Bank and BMO Harris Financing (Bank of Montreal) (or affiliates thereof), which are lenders (or affiliates thereof) under our Credit Agreement, and we are likely to enter into any future derivative instruments with RBC, Comerica Bank, The Bank of Nova Scotia, SunTrust Bank, BMO Harris Financing (Bank of Montreal) or other lenders (or affiliates thereof) party to the Credit Agreement.

Impact of Inflation. Inflation in the United States has been relatively low in recent years and did not have a material impact on our results of operations for the years ended December 31, 2015, 2014 and 2013. Although the impact of inflation has been generally insignificant in recent years, it is still a factor in the U.S. economy and we tend to specifically experience inflationary pressure on the cost of oilfield services and equipment with increases in oil and natural gas prices and with increases in drilling activity in our areas of operations, including the Wolfcamp and Bone Spring plays in the Delaware Basin, the Eagle Ford shale play and the Haynesville shale play. See "Risk Factors — The Unavailability or High Cost of Drilling Rigs, Completion Equipment and Services, Supplies and Personnel, Including Hydraulic Fracturing Equipment and Personnel, Could Adversely Affect Our Ability to Establish and Execute Exploration and Development Plans within Budget and on a Timely Basis, Which Could Have a Material Adverse Effect on Our Financial Condition, Results of Operations and Cash Flows."

Item 8. Financial Statements and Supplementary Data.

Our financial statements appear at the end of this Annual Report on Form 10-K. See the index to the financial statements in Item 15.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure.

On April 9, 2014, the Audit Committee of the Board of Directors of the Company approved the appointment of KPMG LLP ("KPMG") as the Company's independent registered public accounting firm for the year ending December 31, 2014. This appointment constituted the dismissal of Grant Thornton LLP ("Grant Thornton") as the Company's independent registered public accounting firm. Grant Thornton completed its engagement as the Company's independent registered public accounting firm for the year ended December 31, 2013 upon the filing of the Company's Annual Report on Form 10-K. The Audit Committee made its decision in connection with its annual review of the Company's independent registered public accounting firm and after soliciting proposals from several accounting firms.

Grant Thornton's audit report on the Company's consolidated financial statements for the year ended December 31, 2013 did not contain an adverse opinion or disclaimer of opinion, nor was it qualified or modified as to uncertainty, audit scope, or accounting principles.

During the year ended December 31, 2013 and through the current date, there were no (i) disagreements (as defined in Item 304(a)(1)(iv) of Regulation S-K) between the Company and Grant Thornton on any matter of accounting principle or practice, financial statement disclosure or auditing scope or procedure which, if not resolved to Grant

Thornton's satisfaction, would have caused it to make reference to the matter in conjunction with its report on the Company's consolidated financial statements for the year, or (ii) reportable events (as defined in Item 304(a)(1)(v) of Regulation S-K).

Item 9A. Controls and Procedures.
Evaluation of Disclosure Controls and Procedures

Table of Contents

As of the end of the period covered by this Annual Report on Form 10-K, we evaluated the effectiveness of the design and operation of the Company's disclosure controls and procedures (as defined in Rule 13a-15(e) under the Exchange Act) under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer. Based on that evaluation, our Chief Executive Officer and our Chief Financial Officer concluded that the Company's disclosure controls and procedures were effective as of December 31, 2015 to ensure that (i) information required to be disclosed in the reports it files and submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and that (ii) information required to be disclosed under the Exchange Act is accumulated and communicated to the Company's management, including our Chief Executive Officer and our Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting

During the quarter ended December 31, 2015, there were no changes in our internal controls that have materially affected or are reasonably likely to have a material effect on our internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-15(f) of the Exchange Act, as amended. Under the supervision and with the participation of our management, including our Chief Executive Officer and our Chief Financial Officer, we assessed the effectiveness of our internal control over financial reporting as of the end of the period covered by this Annual Report on Form 10-K based on the framework in 2013 "Internal Control — Integrated Framework" issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that assessment, our Chief Executive Officer and our Chief Financial Officer concluded that our internal control over financial reporting was effective to provide reasonable assurance regarding the reliability of our financial reporting and the preparation of our financial statements for external purposes in accordance with U.S. generally accepted accounting principles.

KPMG, our independent registered public accounting firm, has issued an attestation report on our controls over financial reporting as of December 31, 2015 as included herein.

Important Considerations

The effectiveness of our disclosure controls and procedures and our internal control over financial reporting is subject to various inherent limitations, including cost limitations, judgments used in decision making, assumptions about the likelihood of future events, the soundness of our systems, the possibility of human error and the risk of fraud. Moreover, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions and the risk that the degree of compliance with policies or procedures may deteriorate over time. Because of these limitations, there can be no assurance that any system of disclosure controls and procedures or internal control over financial reporting will be successful in preventing all errors or fraud or in making all material information known in a timely manner to the appropriate levels of management.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Matador Resources Company:

We have audited Matador Resources Company's (the "Company") internal control over financial reporting as of December 31, 2015 based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of the Company and subsidiaries as of December 31, 2015 and 2014, and the related consolidated statements of operations, changes in shareholders' equity, and cash flows for the each of the years in the two-year period ended December 31, 2015, and our report dated February 29, 2016 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP
Dallas, Texas
February 29, 2016

Table of Contents

Item 9B. Other Information.

Not applicable.

PART III

Item 10. Directors, Executive Officers and Corporate Governance.

The information required in response to this Item 10 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act, not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 11. Executive Compensation.

The information required in response to this Item 11 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters.

Certain information regarding securities authorized for issuance under our equity compensation plans is included under the caption "Equity Compensation Plan Information" in Part II, Item 5, above, of this Annual Report on Form 10-K and is incorporated by reference herein. Other information required in response to this Item 12 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 13. Certain Relationships and Related Transactions, and Director Independence.

The information required in response to this Item 13 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 14. Principal Accounting Fees and Services.

The information required in response to this Item 14 is incorporated herein by reference to our definitive proxy statement to be filed with the SEC pursuant to Regulation 14A promulgated under the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Table of Contents

PART IV

Item 15. Exhibits and Financial Statement Schedules.

The following documents are filed as part of this Annual Report on Form 10-K:

1. Index to Consolidated Financial Statements, Report of Independent Registered Public Accounting Firm, Consolidated Balance Sheets as of December 31, 2015 and 2014, Consolidated Statements of Operations for the Years Ended December 31, 2015, 2014 and 2013, Consolidated Statements of Changes in Shareholders’ Equity for the Years Ended December 31, 2015, 2014 and 2013 and Consolidated Statements of Cash Flows for the Years Ended December 31, 2015, 2014 and 2013.

2. Exhibits: The exhibits required to be filed by this Item 15 are set forth in the Exhibit Index accompanying this Annual Report on Form 10-K.

EXHIBIT INDEX

Exhibit Number	Description
2.1	Agreement and Plan of Merger, by and among Matador Resources Company (now known as MRC Energy Company), Matador Holdco, Inc. (now known as Matador Resources Company) and Matador Merger Co., dated August 8, 2011 (incorporated by reference to Exhibit 2.1 to our Registration Statement on Form S-1 filed on August 12, 2011).
2.2	Agreement and Plan of Merger, dated as of January 19, 2015, by and among HEYCO Energy Group, Inc., Harvey E. Yates Company, Matador Resources Company and MRC Delaware Resources, LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed on January 20, 2015).*
2.3	Amendment No. 1 to Agreement and Plan of Merger, dated as of January 26, 2015, by and among HEYCO Energy Group, Inc., Harvey E. Yates Company, Matador Resources Company and MRC Delaware Resources, LLC (incorporated by reference to Exhibit 2.3 to our Annual Report on Form 10-K for the year ended December 31, 2014).
2.4	Amendment No. 2 to Agreement and Plan of Merger, dated as of February 2, 2015, by and among HEYCO Energy Group, Inc., Harvey E. Yates Company, Matador Resources Company and MRC Delaware Resources, LLC (incorporated by reference to Exhibit 2.4 to our Annual Report on Form 10-K for the year ended December 31, 2014).
2.5	Amendment No. 3 to Agreement and Plan of Merger, dated as of February 6, 2015, by and among HEYCO Energy Group, Inc., Harvey E. Yates Company, Matador Resources Company and MRC Delaware Resources, LLC (incorporated by reference to Exhibit 2.5 to our Annual Report on Form 10-K for the year ended December 31, 2014).*
2.6	Amendment No. 4 to Agreement and Plan of Merger, dated as of February 27, 2015, by and among HEYCO Energy Group, Inc., Harvey E. Yates Company, Matador Resources Company and MRC Delaware Resources, LLC (incorporated by reference to Exhibit 2.2 to the Current Report on Form 8-K filed on March 2, 2015).*
2.7	Amendment No. 5 to Agreement and Plan of Merger, dated as of April 15, 2015, by and among HEYCO Energy Group, Inc., Matador Resources Company and MRC Delaware Resources, LLC (incorporated by reference to Exhibit 2.1 to the Current Report on Form 8-K filed on April 15, 2015).
2.8	Amendment No. 6 to Agreement and Plan of Merger, dated as of July 20, 2015, by and among HEYCO Energy Group, Inc., Harvey E. Yates Company, Matador Resources Company and MRC Delaware Resources, LLC (incorporated by reference to Exhibit 2.1 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2015).
2.9	Amendment No. 7 to Agreement and Plan of Merger, dated as of August 24, 2015, by and among HEYCO Energy Group, Inc., Harvey E. Yates Company, Matador Resources Company and MRC Delaware Resources, LLC (incorporated by reference to Exhibit 2.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2015).

2.10	Amendment No. 8 to Agreement and Plan of Merger, dated as of September 18, 2015, by and among HEYCO Energy Group, Inc., Harvey E. Yates Company, Matador Resources Company and MRC Delaware Resources, LLC (incorporated by reference to Exhibit 2.3 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2015).
3.1	Certificate of Merger between Matador Resources Company (now known as MRC Energy Company) and Matador Merger Co. (incorporated by reference to Exhibit 3.4 to our Registration Statement on Form S-1 filed on August 12, 2011).
3.2	Amended and Restated Certificate of Formation of Matador Resources Company (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on February 13, 2012).
3.3	Certificate of Amendment to the Amended and Restated Certificate of Formation of Matador Resources Company (incorporated by reference to Exhibit 3.2 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2015).
3.4	Amended and Restated Bylaws of Matador Resources Company, as amended (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on February 25, 2016).
3.5	Statement of Resolutions for Series A Convertible Preferred Stock (incorporated by reference to Exhibit 3.1 to the Current Report on Form 8-K filed on March 2, 2015).

Table of Contents

4.1	Form of Common Stock Certificate (incorporated by reference to Exhibit 4.1 to Amendment No. 4 to our Registration Statement on Form S-1 filed on January 19, 2012).
4.2	Registration Rights Agreement, dated February 27, 2015, between Matador Resources Company and HEYCO Energy Group, Inc. (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on March 2, 2015).
4.3	Voting Agreement, dated February 27, 2015, between Matador Resources Company and HEYCO Energy Group, Inc. (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed on March 2, 2015).
4.4	Registration Rights Agreement, dated as of April 14, 2015, by and among Matador Resources Company, the subsidiary guarantors party thereto and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the several initial purchasers named therein (incorporated by reference to Exhibit 4.2 to the Current Report on Form 8-K filed on April 14, 2015).
4.5	Indenture, dated as of April 14, 2015, by and among Matador Resources Company, the subsidiary guarantors party thereto and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on April 14, 2015).
4.6	First Supplemental Indenture, dated as of October 1, 2015, by and among Matador Resources Company, DLK Wolf Midstream, LLC, the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to the Current Report on Form 8-K filed on October 5, 2015).
4.7	Second Supplemental Indenture, dated as of November 4, 2015, by and among Matador Resources Company, MRC Permian LKE Company, LLC, the Guarantors named therein, and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to the Quarterly Report on Form 10-Q for the quarter ended September 30, 2015).
10.1†	Employment Agreement between Matador Resources Company and Joseph Wm. Foran (incorporated by reference to Exhibit 10.3 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.2†	Employment Agreement between Matador Resources Company and David E. Lancaster (incorporated by reference to Exhibit 10.4 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.3†	Employment Agreement between Matador Resources Company and Matthew Hairford (incorporated by reference to Exhibit 10.5 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.4†	Employment Agreement between Matador Resources Company and Bradley M. Robinson (incorporated by reference to Exhibit 10.6 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.5†	First Amendment to the Employment Agreement between Matador Resources Company and Joseph Wm. Foran (incorporated by reference to Exhibit 10.8 to Amendment No. 1 to our Registration Statement on

	Form S-1 filed on November 14, 2011).
10.6†	First Amendment to the Employment Agreement between Matador Resources Company and David E. Lancaster (incorporated by reference to Exhibit 10.9 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.7†	First Amendment to the Employment Agreement between Matador Resources Company and Matthew Hairford (incorporated by reference to Exhibit 10.10 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.8†	First Amendment to the Employment Agreement between Matador Resources Company and Bradley M. Robinson (incorporated by reference to Exhibit 10.11 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.9†	Second Amendment to the Employment Agreement between Matador Resources Company and Joseph Wm. Foran (incorporated by reference to Exhibit 10.12 to Amendment No. 2 to our Registration Statement on Form S-1 filed on December 30, 2011).
10.10†	Second Amendment to the Employment Agreement between Matador Resources Company and David E. Lancaster (incorporated by reference to Exhibit 10.13 to Amendment No. 2 to our Registration Statement on Form S-1 filed on December 30, 2011).
10.11†	Second Amendment to the Employment Agreement between Matador Resources Company and Matthew Hairford (incorporated by reference to Exhibit 10.14 to Amendment No. 2 to our Registration Statement on Form S-1 filed on December 30, 2011).

10.12†	Second Amendment to the Employment Agreement between Matador Resources Company and Bradley M. Robinson (incorporated by reference to Exhibit 10.15 to Amendment No. 2 to our Registration Statement on Form S-1 filed on December 30, 2011).
10.13†	Matador Resources Company Annual Incentive Plan for Management and Key Employees (incorporated by reference to Exhibit 10.18 to Amendment No. 2 to our Registration Statement on Form S-1 filed on December 30, 2011).
10.14†	Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated October 23, 2003 (incorporated by reference to Exhibit 10.15 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.15†	First Amendment to Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated January 29, 2004 (incorporated by reference to Exhibit 10.16 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.16†	Second Amendment to Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated February 3, 2005 (incorporated by reference to Exhibit 10.17 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.17†	Third Amendment to Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated February 1, 2006 (incorporated by reference to Exhibit 10.18 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.18†	Fourth Amendment to Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated May 1, 2006 (incorporated by reference to Exhibit 10.19 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.19†	Fifth Amendment to Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated February 13, 2008 (incorporated by reference to Exhibit 10.20 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.20†	Sixth Amendment to Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated August 5, 2008 (incorporated by reference to Exhibit 10.21 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.21†	Seventh Amendment to Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated December 12, 2011 (incorporated by reference to Exhibit 10.26 to Amendment No. 2 to our Registration Statement on Form S-1 filed on December 30, 2011).
10.22†	Eighth Amendment to Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan, dated March 8, 2013 (incorporated by reference to Exhibit 10.27 to the Annual Report on Form 10-K for the year ended December 31, 2012).
10.23†	Form of Indemnification Agreement between Matador Resources Company and each of the directors and executive officers thereof (incorporated by reference to Exhibit 10.22 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).

10.24	Purchase, Sale and Participation Agreement, by and between Matador Resources Company (now known as MRC Energy Company) and Orca ICI Development, JV, dated at May 16, 2011 (incorporated by reference to Exhibit 10.25 to Amendment No. 1 to our Registration Statement on Form S-1 filed on November 14, 2011).
10.25	First Amendment to Purchase Sale and Participation Agreement, dated as of June 12, 2013, by and between MRC Energy Company and Orca/ICI Development (incorporated by reference to Exhibit 10.3 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2013).
10.26†	Form of Non-Qualified Stock Option Agreement granted pursuant to the Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan (incorporated by reference to Exhibit 10.36 to the Annual Report on Form 10-K for the year ended December 31, 2011).
10.27†	Form of Incentive Stock Option Agreement granted pursuant to the Matador Resources Company (now known as MRC Energy Company) 2003 Stock and Incentive Plan (incorporated by reference to Exhibit 10.37 to the Annual Report on Form 10-K for the year ended December 31, 2011).
10.28†	Form of Nonqualified Stock Option Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.38 to the Annual Report on Form 10-K for the year ended December 31, 2011).
10.29†	Form of Restricted Stock Unit Award Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.39 to the Annual Report on Form 10-K for the year ended December 31, 2011).

10.30†	Form of Restricted Stock Award Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.40 to the Annual Report on Form 10-K for the year ended December 31, 2011).
10.31†	Form of Nonqualified Stock Option Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan for employees without employment agreements (incorporated by reference to Exhibit 10.4 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2012).
10.32†	Form of Restricted Stock Award Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan for employees without employment agreements (incorporated by reference to Exhibit 10.6 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2012).
10.33†	Form of Performance Restricted Stock and Restricted Stock Unit Award Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan for employees without employment agreements (incorporated by reference to Exhibit 10.7 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2012).
10.34†	Form of Nonqualified Stock Option Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan for employees with employment agreements (incorporated by reference to Exhibit 10.8 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2012).
10.35†	Form of Restricted Stock Award Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan for employees with employment agreements (incorporated by reference to Exhibit 10.9 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2012).
10.36†	Form of Performance Restricted Stock and Restricted Stock Unit Award Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan for employees with employment agreements (incorporated by reference to Exhibit 10.10 to the Quarterly Report on Form 10-Q for the quarter ended March 31, 2012).
10.37	Third Amended and Restated Credit Agreement, dated as of September 28, 2012, by and among MRC Energy Company, as Borrower, the Lending Entities from time to time parties thereto, as Lenders, and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on October 4, 2012).
10.38	Second Amended and Restated Pledge and Security Agreement, by and among MRC Energy Company, Longwood Gathering and Disposal Systems GP, Inc. and Royal Bank of Canada, as Administrative Agent, dated as of September 28, 2012 (incorporated by reference to Exhibit 10.49 to the Annual Report on Form 10-K for the year ended December 31, 2012).
10.39	Second Amended, Restated and Consolidated Unconditional Guaranty, by and among MRC Permian Company, MRC Rockies Company, Matador Production Company, Longwood Gathering and Disposal Systems GP, Inc., Longwood Gathering and Disposal Systems, LP, Matador Resources Company and Royal Bank of Canada, as Administrative Agent, dated as of September 28, 2012 (incorporated by reference to Exhibit 10.50 to the Annual Report on Form 10-K for the year ended December 31, 2012).
10.40	First Amendment to Third Amended and Restated Credit Agreement dated as of March 11, 2013, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as

	Administrative Agent (incorporated by reference to Exhibit 10.51 to the Annual Report on Form 10-K for the year ended December 31, 2012).
10.41	Second Amendment to Third Amended and Restated Credit Agreement dated as of June 4, 2013, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed June 6, 2013).
10.42	Third Amendment to Third Amended and Restated Credit Agreement, dated as of August 7, 2013, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q for the quarter ended June 30, 2013).
10.43	Fourth Amendment to Third Amended and Restated Credit Agreement, dated as of March 12, 2014, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.50 to the Annual Report on Form 10-K for the year ended December 31, 2013).
10.44	Fifth Amendment to Third Amended and Restated Credit Agreement, dated as of September 5, 2014, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on September 8, 2014).

10.45	Sixth Amendment to Third Amended and Restated Credit Agreement, dated as of April 14, 2015, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on April 14, 2015).
10.46	Seventh Amendment to Third Amended and Restated Credit Agreement, dated as of October 16, 2015, by and among MRC Energy Company, as Borrower, the Lenders party thereto and Royal Bank of Canada, as Administrative Agent (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on October 21, 2015).
10.47†	Form of Employment Agreement between Matador Resources Company and each of Craig N. Adams and Ryan C. London (incorporated by reference to Exhibit 10.51 to the Annual Report on Form 10-K for the year ended December 31, 2013).
10.48†	Letter Agreement between Matador Resources Company, David F. Nicklin and David F. Nicklin International Consulting, Inc., dated February 26, 2015 (incorporated by reference to Exhibit 10.51 to our Annual Report on Form 10-K for the year ended December 31, 2014).
10.49†	Form of Employment Agreement between Matador Resources Company and Van H. Singleton, II, effective February 5, 2015 (incorporated by reference to Exhibit 10.52 to our Annual Report on Form 10-K for the year ended December 31, 2014).
10.50	Guaranty, dated February 27, 2015, by Matador Resources Company in favor of PlainsCapital Bank (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on March 2, 2015).
10.51†	Form of Nonqualified Stock Option Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan for employees without employment agreements (incorporated by reference to Exhibit 10.54 to our Annual Report on Form 10-K for the year ended December 31, 2014).
10.52†	Form of Restricted Stock Award Agreement relating to the Matador Resources Company 2012 Long-Term Incentive Plan for employees without employment agreements (incorporated by reference to Exhibit 10.55 to our Annual Report on Form 10-K for the year ended December 31, 2014).
10.53†	Form of Nonqualified Stock Option Agreement relating to the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan for employees without employment agreements (filed herewith).
10.54†	Form of Restricted Stock Award Agreement relating to the Matador Resources Company Amended and Restated 2012 Long-Term Incentive Plan for employees without employment agreements (filed herewith).
10.55†	Amended and Restated Independent Contractor Agreement by and among Matador Resources Company, David F. Nicklin and David F. Nicklin International Consulting, Inc., effective as of April 1, 2015 (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on June 11, 2015).
10.56	Purchase Agreement, dated as of April 9, 2015, by and among Matador Resources Company, the subsidiary guarantors party thereto and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as representative of the several initial purchasers named therein (incorporated by reference to Exhibit 10.1 to the Current Report on Form 8-K filed on April 14, 2015).

10.57†	Amended and Restated 2012 Long-Term Incentive Plan (incorporated by reference to Exhibit 10.2 to the Current Report on Form 8-K filed on June 11, 2015).
10.58	Separation Agreement and Release, dated as of August 31, 2015, by and between Matador Resources Company and Ryan C. London (incorporated by reference to Exhibit 10.2 to the Quarterly Report on Form 10-Q/A for the quarter ended September 30, 2015).
10.59†	Matador Resources Company Nonqualified Deferred Compensation Plan for Non-Employee Directors (filed herewith).
21.1	List of Subsidiaries of Matador Resources Company (filed herewith).
23.1	Consent of KPMG LLP (filed herewith).
23.2	Consent of Grant Thornton LLP (filed herewith).
23.3	Consent of Netherland, Sewell & Associates, Inc. (filed herewith).
31.1	Certification of Principal Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).
31.2	Certification of Principal Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 (filed herewith).

32.1	Certification of Principal Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).
32.2	Certification of Principal Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 (furnished herewith).
99.1	Audit report of Netherland, Sewell & Associates, Inc. (filed herewith).
101	The following financial information from Matador Resources Company's Annual Report on Form 10-K for the year ended December 31, 2015, formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Changes in Shareholders' Equity, (iv) the Consolidated Statements of Cash Flows and (v) the Notes to Consolidated Financial Statements (submitted electronically herewith).
†	Indicates a management contract or compensatory plan or arrangement.
*	Pursuant to Item 601(b)(2) of Regulation S-K, the Company agrees to furnish supplementally a copy of any omitted exhibit or schedule to the SEC upon request.

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this Annual Report on Form 10-K to be signed on its behalf by the undersigned, thereunto duly authorized.

	MATADOR RESOURCES COMPANY
February 29, 2016	By: /s/ Joseph Wm. Foran
	Joseph Wm. Foran
	Chairman and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this Annual Report on Form 10-K has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Table of Contents

Signature	Title	Date
/s/ Joseph Wm. Foran Joseph Wm. Foran	Chairman and Chief Executive Officer (Principal Executive Officer)	February 29, 2016
/s/ David E. Lancaster David E. Lancaster	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	February 29, 2016
/s/ Robert T. Macalik Robert T. Macalik	Vice President and Chief Accounting Officer (Principal Accounting Officer)	February 29, 2016
/s/ Reynald A. Baribault Reynald A. Baribault	Director	February 29, 2016
/s/ David M. Laney David M. Laney	Director	February 29, 2016
/s/ Gregory E. Mitchell Gregory E. Mitchell	Director	February 29, 2016
/s/ Steven W. Ohnimus Steven W. Ohnimus	Director	February 29, 2016
/s/ Carlos M. Sepulveda, Jr. Carlos M. Sepulveda, Jr.	Director	February 29, 2016
/s/ Margaret B. Shannon Margaret B. Shannon	Director	February 29, 2016
/s/ Don C. Stephenson Don C. Stephenson	Director	February 29, 2016
/s/ George M. Yates George M. Yates	Director	February 29, 2016

Table of Contents

GLOSSARY OF OIL AND NATURAL GAS TERMS

The following is a description of the meanings of some of the oil and natural gas industry terms used in this Annual Report on Form 10-K.

Batch drilling. The process by which multiple horizontal wells are drilled from a single pad. In batch drilling, the surface holes for each well are drilled first and then the production holes, including the horizontal laterals for each well, are drilled.

Bbl. One stock tank barrel, or 42 U.S. gallons liquid volume, used in this Annual Report on Form 10-K in reference to crude oil or other liquid hydrocarbons.

Bcf. One billion cubic feet.

BOE. Barrels of oil equivalent, determined using the ratio of one Bbl of crude oil, condensate or natural gas liquids to six Mcf of natural gas.

BOE/d. BOE per day.

Btu or British thermal unit. The quantity of heat required to raise the temperature of one pound of water by one degree Fahrenheit.

Completion. The operations required to establish production of oil or natural gas from a wellbore, usually involving perforations, stimulation and/or installation of permanent equipment in the well, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

Condensate. Liquid hydrocarbons associated with the production of a primarily natural gas reservoir.

Conventional resources. Natural gas or oil that is produced by a well drilled into a geologic formation in which the reservoir and fluid characteristics permit the natural gas or oil to readily flow to the wellbore.

Coring. The act of taking a core. A core is a solid column of rock, usually from two to four inches in diameter, taken as a sample of an underground formation. It is common practice to take cores from wells in the process of being drilled. A core bit is attached to the end of the drill pipe. The core bit then cuts a column of rock from the formation being penetrated. The core is then removed and tested for evidence of oil or natural gas, and its characteristics (porosity, permeability, etc.) are determined.

Developed acreage. The number of acres that are allocated or assignable to productive wells.

Development well. A well drilled into a proved oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole. A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production-related expenses and taxes.

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

Farmin or farmout. An agreement under which the owner of a working interest in an oil or natural gas lease assigns the working interest or a portion of the working interest to another party who desires to drill on the leased acreage. Generally, the assignee is required to drill one or more wells in order to earn its interest in the acreage. The assignor usually retains a royalty or reversionary interest in the lease. The interest received by an assignee is a “farmin” while the interest transferred by the assignor is a “farmout.”

FERC. Federal Energy Regulatory Commission.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition.

Gross acres or gross wells. The total acres or wells in which a working interest is owned.

Held by production. An oil and natural gas property under lease in which the lease continues to be in force after the primary term of the lease in accordance with its terms as a result of production from the property.

Horizontal drilling or well. A drilling operation in which a portion of the well is drilled horizontally within a productive or potentially productive formation. This operation typically yields a horizontal well that has the ability to produce higher volumes than a vertical well drilled in the same formation. A horizontal well is designed to replace multiple vertical wells, resulting in lower capital expenditures for draining like acreage and limiting surface disruption.

Hydraulic fracturing. The technique of improving a well’s production or injection rates by pumping a mixture of fluids into the formation and rupturing the rock, creating an artificial channel. As part of this technique, sand or other material may also be injected into the formation to prop the channel open, so that fluids or gases may more easily flow from the formation, through the fracture channel and into the wellbore. This technique may also be referred to as fracture stimulation.

Liquids. Liquids, or natural gas liquids, are marketable liquid products including ethane, propane, butane, pentane and natural gasoline resulting from the further processing of liquefiable hydrocarbons separated from raw natural gas by a natural gas processing facility.

MBbl. One thousand barrels of crude oil or other liquid hydrocarbons.

MBOE. One thousand BOE.

Mcf. One thousand cubic feet of natural gas.

MMBtu. One million British thermal units.

MMcf. One million cubic feet of natural gas.

NGL. Natural gas liquids.

Net acres or net wells. The sum of the fractional working interest owned in gross acres or wells.

Net revenue interest. The interest that defines the percentage of revenue that an owner of a well receives from the sale of oil, natural gas and/or natural gas liquids that are produced from the well.

NYMEX. New York Mercantile Exchange.

Overriding royalty interest. A fractional interest in the gross production of oil and natural gas under a lease, in addition to the usual royalties paid to the lessor, free of any expense for exploration, drilling, development, operating, marketing and other costs incident to the production and sale of oil and natural gas produced from the lease. It is an interest carved out of the lessee’s working interest, as distinguished from the lessor’s reserved royalty interest.

Pad. The surface constructed to accommodate the drilling, completion and production operations of an oil or natural gas well.

Pad drilling. The process by which multiple horizontal wells are drilled from a single pad. In pad drilling, each well on the pad is drilled to total depth before the next well is initiated.

Permeability. A reference to the ability of oil and/or natural gas to flow through a reservoir.

Petrophysical analysis. The interpretation of well log measurements, obtained from a string of electronic tools inserted into the borehole, and from core measurements, in which rock samples are retrieved from the subsurface, then combining these measurements with other relevant geological and geophysical information to describe the reservoir rock properties.

Play. A set of known or postulated oil and/or natural gas accumulations sharing similar geologic, geographic and temporal properties, such as source rock, migration pathways, timing, trapping mechanism and hydrocarbon type.

Possible reserves. Additional reserves that are less certain to be recognized than probable reserves.

Probable reserves. Additional reserves that are less certain to be recognized than proved reserves but which, in sum with proved reserves, are as likely as not to be recovered.

Producing well, or productive well. A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the well’s production exceed production-related expenses and taxes.

Properties. Natural gas and oil wells, production and related equipment and facilities and natural gas, oil or other mineral fee, leasehold and related interests.

Prospect. A specific geographic area which, based on supporting geological, geophysical or other data and preliminary economic analysis using reasonably anticipated prices and costs, is considered to have potential for the discovery of commercial hydrocarbons.

Proved developed non-producing. Hydrocarbons in a potentially producing horizon penetrated by a wellbore, the production of which has been postponed pending installation of surface equipment or gathering facilities, or pending the production of hydrocarbons from another formation penetrated by the wellbore. The hydrocarbons are classified as proved developed but non-producing reserves.

Proved developed reserves. Proved reserves that can be expected to be recovered through existing wells and facilities and by existing operating methods.

Proved reserves. Reserves of oil and natural gas that have been proved to a high degree of certainty by analysis of the producing history of a reservoir and/or by volumetric analysis of adequate geological and engineering data.

Table of Contents

Proved undeveloped reserves. Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.
Recompletion. Completing in the same wellbore to reach a new reservoir after production from the original reservoir has been abandoned.
Repeatability. The potential ability to drill multiple wells within a prospect or trend.
Reservoir. A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.
Royalty interest. An interest in an oil and natural gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner’s royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.
2-D seismic. The method by which a cross-section of the earth’s subsurface is created through the interpretation of reflecting seismic data collected along a single source profile.
3-D seismic. The method by which a three-dimensional image of the earth’s subsurface is created through the interpretation of reflection seismic data collected over a surface grid. 3-D seismic surveys allow for a more detailed understanding of the subsurface than do 2-D seismic surveys and contribute significantly to field appraisal, exploitation and production.
Spud. The act of beginning to drill an oil or natural gas well.
Trend. A region of oil and/or natural gas production, the geographic limits of which have not been fully defined, having geological characteristics that have been ascertained through supporting geological, geophysical or other data to contain the potential for oil and/or natural gas reserves in a particular formation or series of formations.
Unconventional resource play. A set of known or postulated oil and or natural gas resources or reserves warranting further exploration which are extracted from (i) low-permeability sandstone and shale formations and (ii) coalbed methane. These plays require the application of advanced technology to extract the oil and natural gas resources.
Undeveloped acreage. Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas, regardless of whether such acreage contains proved reserves. Undeveloped acreage is usually considered to be all acreage that is not allocated or assignable to productive wells.
Unproved and unevaluated properties. Properties where no drilling or other actions have been undertaken that permit such properties to be classified as proved.
Vertical well. A hole drilled vertically into the earth from which oil, natural gas or water flows or is pumped.
Visualization. An exploration technique in which the size and shape of subsurface features are mapped and analyzed based upon information derived from well logs, seismic data and other well information.
Volumetric reserve analysis. A technique used to estimate the amount of recoverable oil and natural gas. It involves calculating the volume of reservoir rock and adjusting that volume for rock porosity, hydrocarbon saturation, formation volume factor and recovery factor.
Walking rig. A drilling rig that is capable of moving from one drilling location to another a short distance away using a series of hydraulic “feet” built into the substructure of the rig.
Wellbore. The hole made by a well.
Working interest. The operating interest that gives the owner the right to drill, produce and conduct operating activities on the property and receive a share of production.

Table of Contents

Matador Resources Company and Subsidiaries
CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2015, 2014 and 2013
Contents

Reports of Independent Registered Public Accounting Firms	F-2
Consolidated Financial Statements	
Consolidated Balance Sheets as of December 31, 2015 and 2014	F-4
Consolidated Statements of Operations for the Years Ended December 31, 2015, 2014 and 2013	F-5
Consolidated Statements of Changes in Shareholders' Equity for the Years Ended December 31, 2015, 2014 and 2013	F-6
Consolidated Statements of Cash Flows for the Years Ended December 31, 2015, 2014 and 2013	F-7
Notes to Consolidated Financial Statements	F-8
Unaudited Supplementary Information	F-35

Table of Contents

Report of Independent Registered Public Accounting Firm
The Board of Directors and Shareholders
Matador Resources Company:

We have audited the accompanying consolidated balance sheets of Matador Resources Company (a Texas corporation) and subsidiaries (collectively the “Company”) as of December 31, 2015 and 2014 and the related consolidated statements of operations, changes in shareholders’ equity and cash flows for each of the years in the two-year period ended December 31, 2015. These consolidated financial statements are the responsibility of the Company’s management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Matador Resources Company and subsidiaries as of December 31, 2015 and 2014, and the results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles.

As discussed in Note 2 of the financial statements, the Company changed its method of accounting for debt issuance costs effective January 1, 2014. Additionally, as discussed in Note 2 of the financial statements, the Company changed its method of accounting for deferred taxes effective January 1, 2014.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company’s internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 29, 2016 expressed an unqualified opinion on the effectiveness of the Company’s internal control over financial reporting.

/s/ KPMG LLP
Dallas, Texas
February 29, 2016

Table of Contents

Report of Independent Registered Public Accounting Firm
Board of Directors and Shareholders
Matador Resources Company

We have audited the accompanying consolidated balance sheet of Matador Resources Company (a Texas corporation) and subsidiaries (collectively the "Company") as of December 31, 2013 (not presented herein), and the related consolidated statement of operations, changes in shareholders' equity and cash flows for the year then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audit.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Matador Resources Company and subsidiaries as of December 31, 2013, and the results of their operations and their cash flows for the period ended December 31, 2013 in conformity with accounting principles generally accepted in the United States of America.

/s/ GRANT THORNTON LLP
Dallas, Texas
March 17, 2014

Table of Contents

Matador Resources Company and Subsidiaries
CONSOLIDATED BALANCE SHEETS
(In thousands, except par value and share data)

	December 31, 2015	2014
ASSETS		
Current assets		
Cash	$16,732	$8,407
Restricted cash	44,357	609
Accounts receivable		
Oil and natural gas revenues	16,616	28,976
Joint interest billings	16,999	6,925
Other	10,794	9,091
Derivative instruments	16,284	55,549
Lease and well equipment inventory	2,022	1,212
Prepaid expenses and other assets	3,203	1,649
Total current assets	127,007	112,418
Property and equipment, at cost		
Oil and natural gas properties, full-cost method		
Evaluated	2,122,174	1,617,913
Unproved and unevaluated	387,504	264,419
Other property and equipment	86,387	43,472
Less accumulated depletion, depreciation and amortization	(1,583,659)	(603,732)
Net property and equipment	1,012,406	1,322,072
Other assets		
Other assets	1,448	—
Total other assets	1,448	—
Total assets	$1,140,861	$1,434,490
LIABILITIES AND SHAREHOLDERS’ EQUITY		
Current liabilities		
Accounts payable	$10,966	$17,526
Accrued liabilities	92,369	107,356
Royalties payable	16,493	14,461
Amounts due to affiliates	5,670	2,146
Advances from joint interest owners	700	—
Deferred gain on plant sale	4,830	—
Amounts due to joint ventures	2,793	—
Income taxes payable	2,848	444
Other current liabilities	161	103
Total current liabilities	136,830	142,036
Long-term liabilities		
Borrowings under Credit Agreement	—	338,199
Senior unsecured notes payable	391,254	—
Asset retirement obligations	15,166	11,640
Amounts due to joint ventures	3,956	—
Deferred income taxes	—	73,534
Deferred gain on plant sale	102,506	—
Other long-term liabilities	2,190	2,540

Total long-term liabilities	515,072	425,913
Commitments and contingencies (Note 13)		
Shareholders’ equity		
Common stock — $0.01 par value, 120,000,000 and 80,000,000 shares authorized; 85,567,021 and 73,373,744 shares issued; 85,564,435 and 73,342,777 shares outstanding, respectively	856	734
Additional paid-in capital	1,026,077	724,819
Retained (deficit) earnings	(538,930)	140,855
Total Matador Resources Company shareholders’ equity	488,003	866,408
Non-controlling interest in subsidiaries	956	133
Total shareholders’ equity	488,959	866,541
Total liabilities and shareholders’ equity	$ 1,140,861	$ 1,434,490

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

Table of Contents
Matador Resources Company and Subsidiaries

CONSOLIDATED STATEMENTS OF OPERATIONS
(In thousands, except per share data)

	For the Years Ended December 31,		
	2015	2014	2013
Revenues			
Oil and natural gas revenues	$278,340	$367,712	$269,030
Realized gain (loss) on derivatives	77,094	5,022	(909)
Unrealized (loss) gain on derivatives	(39,265)	58,302	(7,232)
Total revenues	316,169	431,036	260,889
Expenses			
Production taxes and marketing	35,535	33,172	20,973
Lease operating	58,193	51,353	38,720
Depletion, depreciation and amortization	178,847	134,737	98,395
Accretion of asset retirement obligations	734	504	348
Full-cost ceiling impairment	801,166	—	21,229
General and administrative	50,105	32,152	20,779
Total expenses	1,124,580	251,918	200,444
Operating (loss) income	(808,411)	179,118	60,445
Other income (expense)			
Net gain (loss) on asset sales and inventory impairment	908	—	(192)
Interest expense, net of amounts capitalized	(21,754)	(5,334)	(5,687)
Interest and other income	2,365	1,345	225
Total other expense	(18,481)	(3,989)	(5,654)
(Loss) income before income taxes	(826,892)	175,129	54,791
Income tax provision (benefit)			
Current	2,959	133	404
Deferred	(150,327)	64,242	9,293
Total income tax (benefit) provision	(147,368)	64,375	9,697
Net (loss) income	(679,524)	110,754	45,094
Net (income) loss attributable to non-controlling interest in subsidiaries	(261)	17	—
Net (loss) income attributable to Matador Resources Company shareholders	$(679,785)	$110,771	$45,094
Earnings (loss) per common share			
Basic	$(8.34)	$1.58	$0.77
Diluted	$(8.34)	$1.56	$0.77
Weighted average common shares outstanding			
Basic	81,537	70,229	58,777
Diluted	81,537	70,906	58,929

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

Table of Contents
Matador Resources Company and Subsidiaries
CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS’ EQUITY
For the Years Ended December 31, 2015, 2014 and 2013
(In thousands)

	Common Stock		Preferred Stock		Additional paid-in capital	Retained earnings (deficit)	Treasury Stock		Total shareholders' equity attributable to Matador Resources Company	Non-controlling interest in subsidiaries	Total shareholders' equity
	Shares	Amount	Shares	Amount			Shares	Amount			
Balance at January 1, 2013	56,779	$568	—	$—	$404,311	$(15,010)	1,201	$(10,765)	$379,104	$—	$379,104
Issuance of common stock	9,780	98	—	—	148,971	—	—	—	149,069	—	149,069
Cost to issue equity	—	—	—	—	(7,390)	—	—	—	(7,390)	—	(7,390
Issuance of common stock to Board members and advisors	22	—	—	—	57	—	—	—	57	—	57
Stock options expense related to equity-based awards	—	—	—	—	1,232	—	—	—	1,232	—	1,232
Liability-based stock option awards settled	—	—	—	—	162	—	—	—	162	—	162
Restricted stock issued	378	4	—	—	(4)	—	—	—	—	—	—
Restricted stock forfeited	—	—	—	—	(22)	—	105	—	(22)	—	(22
Restricted stock and restricted stock units expense	—	—	—	—	1,618	—	—	—	1,618	—	1,618
Current period net income	—	—	—	—	—	45,094	—	—	45,094	—	45,094
Balance at December 31, 2013	66,959	670	—	—	548,935	30,084	1,306	(10,765)	568,924	—	568,924
Issuance of common stock	7,500	75	—	—	181,800	—	—	—	181,875	—	181,875
Cost to issue equity	—	—	—	—	(590)	—	—	—	(590)	—	(590
Issuance of common stock to Board members and advisors	30	—	—	—	16	—	—	—	16	—	16
Stock options expense related to equity-based awards	—	—	—	—	2,279	—	—	—	2,279	—	2,279
Stock options exercised	8	—	—	—	43	—	—	—	43	—	43
Liability-based stock option awards settled	—	—	—	—	84	—	—	—	84	—	84
Restricted stock issued	212	2	—	—	(2)	—	—	—	—	—	—

Restricted stock forfeited	—	—	—	—	(17)	—	60	—	(17)	—	(17
Restricted stock and restricted stock units expense	—	—	—	—	3,023	—	—	—	3,023	—	3,023
Cancellation of treasury stock	(1,335)	(13)	—	—	(10,752)	—	(1,335)	10,765	—	—	—
Capital contributed to less-than-wholly-owned subsidiaries	—	—	—	—	—	—	—	—	—	150	150
Current period net income (loss)	—	—	—	—	—	110,771	—	—	110,771	(17)	110,754
Balance at December 31, 2014	73,374	734	—	—	724,819	140,855	31	—	866,408	133	866,541
Issuance of common stock	10,329	104	—	—	260,148	—	—	—	260,252	—	260,252
Issuance of preferred stock	—	—	150	1	32,489	—	—	—	32,490	—	32,490
Cost to issue equity	—	—	—	—	(1,151)	—	—	—	(1,151)	—	(1,151
Conversion of preferred stock to common stock	1,500	15	(150)	(1)	(14)	—	—	—	—	—	—
Stock-based compensation expense related to equity-based awards	—	—	—	—	9,333	—	—	—	9,333	—	9,333
Stock options exercised	25	—	—	—	10	—	—	—	10	—	10
Liability-based stock option awards settled	25	—	—	—	446	—	—	—	446	—	446
Restricted stock issued	429	4	—	—	(4)	—	—	—	—	—	—
Restricted stock forfeited	—	—	—	—	—	—	138	—	—	—	—
Vesting of restricted stock units	52	1	—	—	(1)	—	—	—	—	—	—
Cancellation of treasury stock	(167)	(2)	—	—	2	—	(167)	—	—	—	—
Capital contribution from non-controlling interest owners in less-than-wholly-owned subsidiaries	—	—	—	—	—	—	—	—	—	562	562
Current period net (loss) income	—	—	—	—	—	(679,785)	—	—	(679,785)	261	(679,524
Balance at December 31, 2015	85,567	$856	—	$—	$1,026,077	$(538,930)	2	$—	$488,003	$956	$488,959

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

Table of Contents
Matador Resources Company and Subsidiaries

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	For the Years Ended December 31,		
	2015	2014	2013
Operating activities			
Net (loss) income	$(679,524)	$110,754	$45,094
Adjustments to reconcile net (loss) income to net cash provided by operating activities			
Unrealized loss (gain) on derivatives	39,265	(58,302)	7,232
Depletion, depreciation and amortization	178,847	134,737	98,395
Accretion of asset retirement obligations	734	504	348
Full-cost ceiling impairment	801,166	—	21,229
Stock-based compensation expense	9,450	5,524	3,897
Deferred income tax (benefit) provision	(150,327)	64,242	9,293
Amortization of debt issuance costs and discounts	852	—	—
Net (gain) loss on asset sales and inventory impairment	(908)	—	192
Changes in operating assets and liabilities			
Accounts receivable	3,633	(13,318)	(2,160)
Lease and well equipment inventory	(180)	(211)	243
Prepaid expenses	(544)	(783)	(668)
Other assets	(552)	1,212	(548)
Accounts payable, accrued liabilities and other current liabilities	1,375	607	(3,638)
Royalties payable	1,654	6,663	1,257
Advances from joint interest owners	700	—	(1,515)
Income taxes payable	2,405	39	404
Other long-term liabilities	489	(187)	415
Net cash provided by operating activities	208,535	251,481	179,470
Investing activities			
Proceeds from sale of assets	139,836	79	—
Oil and natural gas properties capital expenditures	(432,715)	(560,849)	(363,192)
Expenditures for other property and equipment	(64,499)	(9,152)	(3,977)
Business combination, net of cash acquired	(24,028)	—	—
Maturities of certificates of deposit, net of purchases	—	—	230
Restricted cash	(43,098)	—	—
Restricted cash in less-than-wholly-owned subsidiaries	(650)	(609)	—
Net cash used in investing activities	(425,154)	(570,531)	(366,939)
Financing activities			
Repayments of borrowings	(476,982)	(180,000)	(130,000)
Borrowings under Credit Agreement	125,000	320,000	180,000
Proceeds from issuance of common stock	188,720	181,875	149,069
Proceeds from issuance of senior unsecured notes	400,000	—	—
Cost to issue equity	(1,158)	(590)	(7,390)
Cost to issue senior unsecured notes	(9,598)	—	—
Proceeds from stock options exercised	10	43	—
Capital commitment from non-controlling interest owners of less-than-wholly-owned subsidiaries	562	150	—
Taxes paid related to net share settlement of stock-based compensation	(1,610)	(308)	(18)

Net cash provided by financing activities	224,944	321,170	191,661
Increase in cash	8,325	2,120	4,192
Cash at beginning of year	8,407	6,287	2,095
Cash at end of year	$16,732	$8,407	$6,287

Supplemental disclosures of cash flow information (Note 14)

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

Table of Contents

Matador Resources Company and Subsidiaries
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2015, 2014 and 2013

NOTE 1 — NATURE OF OPERATIONS

Matador Resources Company, a Texas corporation ("Matador" and, collectively with its subsidiaries, the "Company"), is an independent energy company engaged in the exploration, development, production and acquisition of oil and natural gas resources in the United States, with an emphasis on oil and natural gas shale and other unconventional plays. The Company's current operations are focused primarily on the oil and liquids-rich portion of the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. The Company also operates in the Eagle Ford shale play in South Texas and the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Basis of Presentation

The consolidated financial statements include the accounts of Matador Resources Company and its wholly-owned and majority-owned subsidiaries. These consolidated financial statements have been prepared in accordance with generally accepted accounting principles in the United States of America ("U.S. GAAP"). Accordingly, the Company consolidates certain subsidiaries that are less-than-wholly-owned and the net income and equity attributable to the non-controlling interest in these subsidiaries have been reported separately as required by Accounting Standards Codification ("ASC") 810. The Company proportionately consolidates certain joint ventures that are less-than-wholly-owned and are involved in oil and natural gas exploration. All intercompany balances and transactions have been eliminated in consolidation.

The Company has only one reportable operating segment, which is oil and natural gas exploration and production. The Company has a single, company-wide management team that allocates capital resources to maximize profitability and measures financial performance as a single enterprise. Although the Company's midstream operations have increased in significance during 2015, as of December 31, 2015, the midstream operations do not meet any of the thresholds which would require segment reporting.

Reclassifications

Certain reclassifications have been made to the prior years' financial statements to conform to the current year presentation. These reclassifications had no effect on previously reported results of operations, cash flows or retained earnings.

Change in Accounting Principles

The Company adopted Accounting Standards Update ("ASU") 2015-03, Interest - Imputation of Interest (Subtopic 935-30): Simplifying the Presentation of Debt Issuance Costs, effective June 30, 2015. This standard requires companies that have historically presented debt issuance costs as an asset to present those costs as a direct deduction from the carrying amount of the underlying debt liability. To the extent that there are no borrowings under the Credit Agreement (as defined in Note 6), the related deferred loan costs will continue to be classified as an asset. The guidance required retrospective application in the financial statements. As such, the Company reclassified $1.8 million at December 31, 2014 related to deferred loan costs for the Credit Agreement which had previously been presented in "Prepaid expenses and other assets." As the Company had no borrowings outstanding under the Credit Agreement at December 31, 2015, approximately $1.8 million of deferred loan costs related to the Credit Agreement are included in "Prepaid expenses and other assets." The Company's senior unsecured notes are presented net of approximately $8.7 million of deferred loan costs at December 31, 2015. The Company had no senior unsecured notes outstanding at December 31, 2014.

The Company also adopted ASU 2015-17, Income Taxes (Topic 740), effective December 31, 2015. This standard requires deferred income tax liabilities and assets to be classified as noncurrent in a classified statement of financial position. The standard permitted either prospective or retrospective application. The Company elected to apply the standard retrospectively. As such, the Company reclassified approximately $19.8 million of "Deferred income taxes" from current to noncurrent on the consolidated balance sheet as of December 31, 2014. As the Company recorded a valuation allowance against all of the Company’s deferred tax assets as of December 31, 2015 (as described in Note 7), adoption of this standard had no impact on the consolidated balance sheet as of December 31, 2015.

Use of Estimates

The preparation of financial statements in conformity with U.S. GAAP requires management to make estimates and assumptions that affect the amounts reported in the financial statements and accompanying notes. These estimates and assumptions may also affect disclosure of contingent assets and liabilities at the date of the financial statements and the reported

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

amounts of revenues and expenses during the reporting period. While the Company believes its estimates are reasonable, changes in facts and assumptions or the discovery of new information may result in revised estimates. Actual results could differ from these estimates.

The Company's consolidated financial statements are based on a number of significant estimates, including oil and natural gas revenues, accrued assets and liabilities, stock-based compensation, valuation of derivative instruments, deferred tax assets and liabilities and oil and natural gas reserves. The estimates of oil and natural gas reserves quantities and future net cash flows are the basis for the calculations of depletion and impairment of oil and natural gas properties, as well as estimates of asset retirement obligations and certain tax accruals. The Company's oil and natural gas reserves estimates, which are inherently imprecise and based upon many factors that are beyond the Company's control, including oil and natural gas prices, are prepared by the Company's engineering staff in accordance with guidelines established by the Securities and Exchange Commission ("SEC") and then audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers.

Restricted Cash

Restricted cash represents a portion of the cash paid for the Loving County System by EnLink (as described in Note 5) directly to a qualified intermediary to facilitate like-kind-exchange transactions for federal income tax purposes as well as cash held by the Company's less-than-wholly-owned subsidiaries. Not all of the cash deposited with the qualified intermediary was used for like-kind-exchange transactions and, in January 2016, the remaining balance of $42.1 million was returned to the Company by the qualified intermediary to be used for general corporate purposes. By contractual agreement, the cash in the account held by the Company's less-than-wholly-owned subsidiaries is not to be commingled with other Company cash and is to be used only to fund the capital expenditures and operations of these less-than-wholly-owned subsidiaries.

Accounts Receivable

The Company sells its operated oil, natural gas and natural gas liquids production to various purchasers (see " — Revenue Recognition" below). Due to the nature of the markets for oil, natural gas and natural gas liquids, the Company does not believe that the loss of any one purchaser would significantly impact operations. In addition, the Company may participate with industry partners in the drilling, completion and operation of oil and natural gas wells. Substantially all of the Company's accounts receivable are due from either purchasers of oil, natural gas and natural gas liquids or participants in oil and natural gas wells for which the Company serves as the operator. Accounts receivable are due within 30 to 60 days of the production date and 30 days of the billing date and are stated at amounts due from purchasers and industry partners. Amounts are considered past due if they have been outstanding for 60 days or more. No interest is typically charged on past due amounts.

The Company reviews its need for an allowance for doubtful accounts on a periodic basis and determines the allowance, if any, by considering the length of time past due, previous loss history, future net revenues of the debtor's ownership interest in oil and natural gas properties operated by the Company and the debtor's ability to pay its obligations, among other things. The Company has no allowance for doubtful accounts related to its accounts receivable for any reporting period presented.

Lease and Well Equipment Inventory

Lease and well equipment inventory is stated at the lower of cost or market and consists entirely of equipment scheduled for use in future well operations or equipment held for sale.

Oil and Natural Gas Properties

The Company uses the full-cost method of accounting for its investments in oil and natural gas properties. Under this method of accounting, all costs associated with the acquisition, exploration and development of oil and natural gas properties and reserves, including unproved and unevaluated property costs, are capitalized as incurred and accumulated in a single cost center representing the Company's activities, which are undertaken exclusively in the United States. Such costs include lease acquisition costs, geological and geophysical expenditures, lease rentals on undeveloped properties, costs of drilling both productive and non-productive wells, capitalized interest on qualifying projects and general and administrative expenses directly related to acquisition, exploration and development activities, but do not include any costs related to production, selling or general corporate administrative activities. The Company capitalized $6.9 million, $6.4 million and $3.7 million of its general and administrative costs in 2015, 2014 and 2013, respectively. The Company capitalized $3.9 million, $2.8 million and $1.9 million of its interest expense for the years ended December 31, 2015, 2014 and 2013, respectively.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

Capitalized costs of oil and natural gas properties are amortized using the unit-of-production method based upon production and estimates of proved reserves quantities. Unproved and unevaluated property costs are excluded from the amortization base used to determine depletion. Unproved and unevaluated properties are assessed for possible impairment on a periodic basis based upon changes in operating or economic conditions. This assessment includes consideration of the following factors, among others: the assignment of proved reserves, geological and geophysical evaluations, intent to drill, remaining lease term and drilling activity and results. Upon impairment, the costs of the unproved and unevaluated properties are immediately included in the amortization base. Exploratory dry holes are included in the amortization base immediately upon determination that the well is not productive.

Sales of oil and natural gas properties are accounted for as adjustments to net capitalized costs with no gain or loss recognized, unless such adjustments would significantly alter the relationship between net capitalized costs and proved reserves of oil and natural gas. All costs related to production activities and maintenance and repairs are expensed as incurred. Significant workovers that increase the properties' reserves are capitalized.

Ceiling Test

The net capitalized costs of oil and natural gas properties are limited to the lower of unamortized costs less related deferred income taxes or the cost center "ceiling." The cost center ceiling is defined as the sum of:

(a) the present value, discounted at 10%, of future net revenues of proved oil and natural gas reserves, reduced by the estimated costs of developing these reserves, plus

(b) unproved and unevaluated property costs not being amortized, plus

(c) the lower of cost or estimated fair value of unproved and unevaluated properties included in the costs being amortized, if any, less

(d) income tax effects related to the properties involved.

Any excess of the Company's net capitalized costs above the cost center ceiling as described above is charged to operations as a full-cost ceiling impairment. The fair value of the Company's derivative instruments is not included in the ceiling test computation as the Company does not designate these instruments as hedge instruments for accounting purposes.

The estimated present value of after-tax future net cash flows from proved oil and natural gas reserves is highly dependent upon the quantities of proved reserves, the estimation of which requires substantial judgment. The associated commodity prices and the applicable discount rate used in these estimates are in accordance with guidelines established by the SEC. Under these guidelines, oil and natural gas reserves are estimated using then-current operating and economic conditions, with no provision for price and cost changes in future periods except by contractual arrangements. Future net revenues are calculated using prices that represent the arithmetic averages of the first-day-of-the-month oil and natural gas prices for the previous 12-month period and a 10% discount factor is used to determine the present value of future net revenues. For the period from January through December 2015, these average oil and natural gas prices were $46.79 per barrel and $2.59 per MMBtu, respectively. For the period from January through December 2014, these average oil and natural gas prices were $91.48 per barrel and $4.35 per MMBtu, respectively. For the period from January through December 2013, these average oil and natural gas prices were $93.42 per barrel and $3.67 per MMBtu, respectively. In estimating the present value of after-tax future net cash flows from proved oil and natural gas reserves, the average oil prices were further adjusted by property for quality, transportation and marketing fees and regional price differentials, and the average natural gas prices were further adjusted by property for energy content, transportation and marketing fees and regional price differentials.

For the year ended December 31, 2015, the Company's net capitalized costs less related deferred income taxes exceeded the full-cost ceiling. As a result, the Company recorded an impairment charge of $801.2 million, exclusive of tax effect, to its consolidated statement of operations for the year ended December 31, 2015 with the related deferred income tax credit recorded net of a valuation allowance (see Note 7).

During the year ended December 31, 2014, the Company’s net capitalized costs less related deferred income taxes did not exceed the full-cost ceiling. As a result, the Company recorded no impairment to its net capitalized costs during the year ended December 31, 2014.

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

During the year ended December 31, 2013, the Company recorded an impairment charge of $21.2 million, exclusive of tax effect, to its net capitalized costs. This charge is reflected in the Company's consolidated statement of operations for the year ended December 31, 2013.

As a non-cash item, the full-cost ceiling impairment impacts the accumulated depletion and the net carrying value of the Company's assets on its consolidated balance sheets, as well as the corresponding shareholders' equity, but it has no impact on the Company's net cash flows as reported. Changes in oil and natural gas production rates, oil and natural gas prices, reserves estimates, future development costs and other factors will determine the Company's actual ceiling test computation and impairment analyses in future periods.

Other Property and Equipment

Other property and equipment are recorded at historical cost. Software, furniture, fixtures and other equipment are depreciated over their useful life (five to 10 years) using the straight-line method. Midstream support equipment and facilities include the Company's pipelines, processing facilities and salt water disposal systems and are depreciated over a 30-year useful life using the straight-line, mid-month convention method. Leasehold improvements are depreciated over the lesser of their useful lives or the term of the lease. Maintenance and repair costs that do not extend the useful life of the property or equipment are expensed as incurred.

Asset Retirement Obligations

The Company recognizes the fair value of an asset retirement obligation in the period in which it is incurred if a reasonable estimate of fair value can be made. The asset retirement obligation is recorded as a liability at its estimated present value, with an offsetting increase recognized in oil and natural gas properties or support equipment and facilities on the consolidated balance sheets. Periodic accretion of the discounted value of the estimated liability is recorded as an expense in the consolidated statements of operations.

Derivative Financial Instruments

From time to time, the Company uses derivative financial instruments to mitigate its exposure to commodity price risk associated with oil, natural gas and natural gas liquids prices. The Company's derivative financial instruments are recorded on the consolidated balance sheets as either an asset or a liability measured at fair value. The Company has elected not to apply hedge accounting for its existing derivative financial instruments, and as a result, the Company recognizes the change in derivative fair value between reporting periods currently in its consolidated statements of operations. The fair value of the Company's derivative financial instruments is determined using industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value of money and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Realized gains and realized losses from the settlement of derivative financial instruments and unrealized gains and unrealized losses from valuation changes in the remaining unsettled derivative financial instruments are reported under Revenues in the consolidated statements of operations. See Note 11 for additional information about the Company's derivative instruments.

Revenue Recognition

The Company follows the sales method of accounting for its oil, natural gas and natural gas liquids revenues, whereby it recognizes revenue, net of royalties, on all oil, natural gas and natural gas liquids sold to purchasers regardless of whether the sales are proportionate to its ownership in the property. Under this method, revenue is recognized at the time oil, natural gas and natural gas liquids are produced and sold, and the Company accrues for revenue earned but not yet received.

For the year ended December 31, 2015, the Company had three significant purchasers that accounted for approximately 59% of its total oil, natural gas and natural gas liquids revenues. For the years ended December 31, 2014 and 2013, the Company had three and five significant purchasers that accounted for approximately 68% and 87%, respectively, of its total oil, natural gas and natural gas liquids revenues. Due to the nature of the markets for oil, natural gas and natural gas liquids, the Company does not believe the loss of any one purchaser would have a material adverse impact on the Company's financial condition, results of operations or cash flows for any significant period of time. At December 31, 2015, 2014 and 2013, approximately 39%, 44% and 81%, respectively, of the Company's accounts receivable, including joint interest billings, related to these purchasers.

Table of Contents

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

Stock-Based Compensation
The Company grants common stock, stock options, restricted stock and restricted stock units to members of its Board of Directors and selected employees. All such awards are measured at fair value on the date of grant and are generally recognized as a component of general and administrative expenses in the accompanying statements of operations on a straight-line basis over the awards' vesting periods. The Company accounts for all outstanding stock options granted under the 2003 Plan (as described and defined in Note 8) as liability instruments as a result of the Company purchasing shares from certain of its employees to assist them in the exercise of outstanding options of the Company's common stock.
The Company utilizes the Black Scholes Merton option pricing model to measure the fair value of stock options, the closing stock price on the date of grant to measure restricted stock and restricted stock unit awards and the Monte Carlo simulation method to measure the fair value of performance units.
The Company's consolidated statements of operations for the years ended December 31, 2015, 2014 and 2013 include a stock-based compensation (non-cash) expense of $9.5 million, $5.5 million and $3.9 million, respectively. This stock-based compensation expense includes common stock issuances and restricted stock units expense totaling $0.9 million, $0.3 million and $0.3 million in 2015, 2014 and 2013, respectively, paid to members of the Board of Directors and advisors as compensation for their services to the Company.
Income Taxes
The Company accounts for income taxes using the asset and liability approach for financial accounting and reporting. The Company evaluates the probability of realizing the future benefits of its deferred tax assets and records a valuation allowance for the portion of any deferred tax assets when it is more likely than not that the benefit from the deferred tax asset will not be realized.
The Company recognizes the tax benefit of an uncertain tax position only if it is more likely than not that the tax position will be sustained upon examination by the taxing authorities based on the technical merits of the position. For tax positions meeting the more likely than not threshold, the amount recognized in the financial statements is the benefit that has a greater than 50% likelihood of being realized upon ultimate settlement with the relevant tax authority. At December 31, 2015, 2014 and 2013, the Company had not established any reserves for, nor recorded any unrecognized tax benefits related to, uncertain tax positions.
When necessary, the Company would include interest assessed by taxing authorities in "Interest expense" and penalties related to income taxes in "Other expense" on its consolidated statements of operations. The Company did not record any interest or penalties related to income tax for the years ended December 31, 2015, 2014 and 2013.
Allocation of Purchase Price in Business Combinations
As part of the Company's business strategy, it periodically pursues the acquisition of oil and natural gas properties. The purchase price in a business combination is allocated to the assets acquired and liabilities assumed based on their fair values as of the acquisition date, which may occur many months after the announcement date. Therefore, while the consideration to be paid may be fixed, the fair value of the assets acquired and liabilities assumed is subject to change during the period between the announcement date and the acquisition date. The most significant estimates in the allocation typically relate to the value assigned to proved oil and natural gas reserves and unproved and unevaluated properties. As the allocation of the purchase price is subject to significant estimates and subjective judgments, the accuracy of this assessment is inherently uncertain.
Earnings Per Common Share
The Company reports basic earnings per common share, which excludes the effect of potentially dilutive securities, and diluted earnings per common share, which includes the effect of all potentially dilutive securities, unless their impact is anti-dilutive.

The following are reconciliations of the numerators and denominators used to compute the Company's basic and diluted earnings per common share as reported for the years ended December 31, 2015, 2014 and 2013 (in thousands, except per share data).

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — CONTINUED
December 31, 2015, 2014 and 2013

NOTE 2 — SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES — Continued

	Year Ended December 31,		
	2015	2014	2013
Net (loss) income attributable to Matador Resources Company shareholders — numerator	$(679,785)	$110,771	$45,094
Weighted average common shares outstanding — denominator			
Basic	81,537	70,229	58,777
Dilutive effect of options, restricted stock units and preferred shares	—	677	152
Diluted weighted average common shares outstanding	81,537	70,906	58,929
Earnings (loss) per common share attributable to Matador Resources Company shareholders			
Basic	$(8.34)	$1.58	$0.77
Diluted	$(8.34)	$1.56	$0.77

A total of 2.4 million options to purchase shares of the Company's common stock and 0.1 million restricted stock units were excluded from the calculations above for the year ended December 31, 2015 because their effects were anti-dilutive. Additionally, 0.9 million restricted shares, which are participating securities, were excluded from the calculations above for the year ended December 31, 2015 as the security holders do not have the obligation to share in the losses of the Company.

Credit Risk

The Company's cash is held in financial institutions and at times these amounts exceed the insurance limits of the Federal Deposit Insurance Corporation. Management believes, however, that the Company's counterparty risks are minimal based on the reputation and history of the institutions selected.

The Company uses derivative financial instruments to mitigate its exposure to oil, natural gas and natural gas liquids price volatility. These transactions expose the Company to potential credit risk from its counterparties. The Company manages counterparty credit risk through established internal derivatives policies that are reviewed on an ongoing basis. Additionally, all of the Company's commodity derivative contracts at December 31, 2015 are with The Bank of Nova Scotia and BMO Harris Financing (Bank of Montreal) (or affiliates thereof), parties that are lenders (or affiliates thereof) under the Company's Credit Agreement.

Accounts receivable constitute the principal component of additional credit risk to which the Company may be exposed. The Company attempts to minimize credit risk exposure to counterparties by monitoring the financial condition and payment history of its purchasers and joint interest partners.

Recent Accounting Pronouncements

Recognition and Measurement of Financial Assets and Financial Liabilities. In January 2016, the FASB issued ASU 2016-01, Recognition and Measurement of Financial Assets and Financial Liabilities, which changes certain guidance related to the recognition, measurement, presentation and disclosure of financial instruments. This update is effective for fiscal years beginning after December 15, 2017, including interim periods within those fiscal years. Early adoption is not permitted for the majority of the update, but is permitted for two of its provisions. The Company is currently evaluating the new guidance and has not determined the impact this standard may have on its consolidated financial statements.

Revenue from Contracts with Customers. In May 2014, the FASB issued ASU 2014-09, Revenue from Contracts with Customers (Topic 606), which specifies how and when to recognize revenue. This standard requires expanded disclosures surrounding revenue recognition and is intended to improve, and converge with international standards, the financial reporting requirements for revenue from contracts with customers. In August 2015, the FASB issued

ASU 2015-14, which defers the effective date of ASU 2014-09 for one year to fiscal years beginning after December 15, 2017. The Company is currently evaluating the impact, if any, of the adoption of this ASU on its consolidated financial statements.

NOTE 3 — PROPERTY AND EQUIPMENT

The following table presents a summary of the Company's property and equipment balances as of December 31, 2015 and 2014 (in thousands).

	December 31, 2015	2014
Oil and natural gas properties		
Evaluated (subject to amortization)	$2,122,174	$1,617,913
Unproved and unevaluated (not subject to amortization)	387,504	264,419
Total oil and natural gas properties	2,509,678	1,882,332
Accumulated depletion	(1,574,040)	(596,218)
Net oil and natural gas properties	935,638	1,286,114
Other property and equipment		
Midstream support equipment and facilities	78,564	38,135
Furniture, fixtures and other equipment	2,918	2,633
Software	2,193	1,733
Land	1,539	—
Leasehold improvements	1,173	971
Total other property and equipment	86,387	43,472
Accumulated depreciation	(9,619)	(7,514)
Net other property and equipment	76,768	35,958
Net property and equipment	$1,012,406	$1,322,072

The following table provides a breakdown of the Company's unproved and unevaluated property costs not subject to amortization as of December 31, 2015 and the year in which these costs were incurred (in thousands).

Description	2015	2014	2013	2012 and prior	Total
Costs incurred for					
Property acquisition	$238,436	$68,207	$41,800	$672	$349,115
Exploration wells	14,650	30	—	—	14,680
Development wells	22,558	1,151	—	—	23,709
Total	$275,644	$69,388	$41,800	$672	$387,504

Property acquisition costs primarily include leasehold costs paid to secure oil and natural gas mineral leases, but may also include broker and legal expenses, geological and geophysical expenses and capitalized internal costs associated with developing oil and natural gas prospects on these properties. Property acquisition costs are transferred into the amortization base on an ongoing basis as these properties are evaluated and proved reserves are established or impairment is determined. Unproved and unevaluated properties are assessed for possible impairment on a periodic basis based upon changes in operating or economic conditions.

Property acquisition costs incurred which remain in unproved and unevaluated property at December 31, 2015 are related primarily to the Company's leasehold acquisitions in the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas during the past three years. These costs include, in particular, the cost of the acreage acquired as part of the HEYCO Merger (as described and defined in Note 5) in 2015. These costs are associated with acreage for which proved reserves have yet to be assigned. A significant portion of these costs are associated with properties which are held by production or have automatic lease renewal options. As the Company drills wells and assigns proved reserves to these properties or determines that certain portions of this acreage, if any, cannot be assigned proved reserves, portions of these costs are transferred to the amortization base.

Costs excluded from amortization also include those costs associated with exploration and development wells in progress or awaiting completion at year-end. These costs are transferred into the amortization base on an ongoing basis as these wells are completed and proved reserves are established or confirmed. These costs totaled $38.4 million at December 31, 2015. Of this

NOTE 3 — PROPERTY AND EQUIPMENT — Continued

total, $14.7 million was associated with exploration wells and $23.7 million was associated with development wells. The Company anticipates that most of the $38.4 million associated with these wells in progress at December 31, 2015 will be transferred to the amortization base during 2016.

NOTE 4 — ASSET RETIREMENT OBLIGATIONS

In general, the Company's asset retirement obligations relate to future costs associated with plugging and abandonment of its oil and natural gas wells, removal of equipment and facilities from leased acreage and returning such land to its original condition. The amounts recognized are based on numerous estimates and assumptions, including future retirement costs, future recoverable quantities of oil and natural gas, future inflation rates and the Company's credit-adjusted risk-free interest rate. Revisions to the liability can occur due to changes in these estimates and assumptions or if federal or state regulators enact new plugging and abandonment requirements. At the time of the actual plugging and abandonment of its oil and natural gas wells, the Company includes any gain or loss associated with the operation in the amortization base to the extent the actual costs are different from the estimated liability.

The following table summarizes the changes in the Company's asset retirement obligations for the years ended December 31, 2015 and 2014 (in thousands).

	Year Ended December 31,	
	2015	2014
Beginning asset retirement obligations	$11,951	$7,484
Liabilities incurred during period	4,508	2,322
Liabilities settled during period	(588)	(22)
Revisions in estimated cash flows	(1,185)	1,663
Accretion expense	734	504
Ending asset retirement obligations	15,420	11,951
Less: current asset retirement obligations [1]	(254)	(311)
Long-term asset retirement obligations	$15,166	$11,640

(1) Included in accrued liabilities in the Company's consolidated balance sheets at December 31, 2015 and 2014.

NOTE 5 — BUSINESS COMBINATIONS AND DIVESTITURES

Business Combinations

On February 27, 2015, the Company completed a business combination with Harvey E. Yates Company ("HEYCO"), a subsidiary of HEYCO Energy Group, Inc., through a merger of HEYCO with and into a wholly-owned subsidiary of Matador (the "HEYCO Merger"). In the HEYCO Merger, the Company obtained certain oil and natural gas producing properties and undeveloped acreage located in Lea and Eddy Counties, New Mexico, consisting of approximately 58,600 gross (18,200 net) acres strategically located between the Company's existing acreage in its Ranger and Rustler Breaks prospect areas. HEYCO, headquartered in Roswell, New Mexico, was privately-owned prior to the transaction. As consideration for the business combination, Matador paid approximately $33.6 million in cash and assumed debt obligations and issued 3,300,000 shares of Matador common stock and 150,000 shares of a new series of Matador Series A Convertible Preferred Stock ("Series A Preferred Stock") to HEYCO Energy Group, Inc. (convertible into ten shares of common stock for each one share of Series A Preferred Stock upon the effectiveness of an amendment to the Company's Amended and Restated Certificate of Formation to increase the number of authorized shares of common stock; the Series A Preferred Stock converted to common stock on April 6, 2015). Matador incurred an additional $4.5 million for customary purchase price adjustments, including adjusting for production, revenues and operating and capital expenditures from September 1, 2014 to closing. As a result of the HEYCO Merger, Matador incurred deferred tax liabilities of approximately $76.8 million and assumed other liabilities of approximately $4.5 million. The

HEYCO Merger was accounted for using the acquisition method under ASC Topic 805, “Business Combinations,” which requires the assets acquired and liabilities assumed to be recorded at fair value as of the respective acquisition date.

During the year ended December 31, 2015, the Company incurred approximately $2.5 million of transaction costs associated with the HEYCO Merger, which were included in “General and administrative” costs in the consolidated statement of operations. The majority of the assets acquired in the HEYCO Merger were in the form of non-producing acreage. The producing wells acquired in the HEYCO Merger did not have a material impact on the Company’s revenues or results of operations for the year ended December 31, 2015.

The preliminary allocation of the consideration given related to this business combination was as follows (in thousands). The Company anticipates that the allocation of the consideration given will be finalized during the first quarter of 2016 upon determination of the final customary purchase price adjustments.

Consideration given	Allocation
Cash	$26,148
Preferred shares issued	32,490
Common shares issued	71,478
Total consideration given	$130,116
Allocation of purchase price	
Cash acquired	$626
Accounts receivable	3,542
Inventory	180
Other current assets	106
Oil and natural gas properties	
Evaluated oil and natural gas properties	16,524
Unproved oil and unevaluated natural gas properties	202,310
Other property and equipment	178
Accounts payable	(2,034)
Accrued liabilities	(495)
Current note payable	(11,982)
Asset retirement obligations	(2,046)
Deferred tax liabilities incurred	(76,793)
Net assets acquired	$130,116

Divestitures

On October 1, 2015, the Company completed the sale of its wholly-owned subsidiary that owned certain natural gas gathering and processing assets in the Delaware Basin in Loving County, Texas (the “Loving County System”) to an affiliate of EnLink Midstream Partners, LP (“EnLink”). The Loving County System included a cryogenic natural gas processing plant with approximately 35 MMcf per day of inlet capacity (the “Processing Plant”) and approximately six miles of high-pressure gathering pipeline which connects the Company’s gathering system to the Processing Plant. Pursuant to the terms of the transaction, EnLink paid approximately $143.4 million and the Company received net proceeds of approximately $139.8 million, after deducting customary purchase price adjustments of approximately $3.6 million. In conjunction with the sale of the Loving County System, the Company dedicated its leasehold interests in Loving County as of the closing date pursuant to a 15-year fixed-fee natural gas gathering and processing agreement and provided a volume commitment in exchange for priority one service. See Note 13 for more information related to this agreement.

Due to the terms of the agreement, the transaction was accounted for as a sale and leaseback transaction; the carrying value of the net assets sold of approximately $31.0 million was removed from the consolidated balance sheet as of December 31, 2015 and the resulting difference of approximately $108.4 million between the net proceeds received less closing costs of $0.4 million and the basis of the assets sold was recorded as deferred gain on plant sale and will be recognized as a gain on asset sales over the 15-year term of the gathering and processing agreement. As such, the

Company recognized a gain on the

sale for the year ended December 31, 2015 of $1.1 million in the consolidated statement of operations, with $4.8 million remaining as a current deferred gain, representing the gain expected to be recognized in 2016, and $102.5 million remaining as noncurrent deferred gain on the consolidated balance sheet as of December 31, 2015. Should certain events occur in the future that cause a redetermination of whether the sale is required to be accounted for as a sale and leaseback transaction, the remaining deferred gain would be recognized prior to the completion of the agreement. Such events could include EnLink's construction or acquisition of another plant that could process the Company's natural gas, as permitted by the gathering and processing agreement, or the Company's determination that future production would not be sufficient to fully utilize the capacity of the plant whereby the Company elects to lower its committed volumes to be processed at the plant.

The Company can, at its option, dedicate any future leasehold acquisitions in Loving County to EnLink. In addition, the Company retained its natural gas gathering system up to a central delivery point and its other midstream assets in the area, including oil and water gathering systems and salt water disposal wells.

NOTE 6 — DEBT

Credit Agreement

On September 28, 2012, the Company amended and restated its revolving credit agreement with the lenders party thereto (the "Credit Agreement"), which increased the maximum facility amount from $400.0 million to $500.0 million. MRC Energy Company, which is a subsidiary of Matador and directly or indirectly holds the ownership interests in the Company's other operating subsidiaries, other than its less-than-wholly-owned subsidiaries, is the borrower under the Credit Agreement. Borrowings are secured by mortgages on at least 80% of the Company's proved oil and natural gas properties and by the equity interests of MRC Energy Company's wholly-owned subsidiaries, which are also guarantors. In addition, all obligations under the Credit Agreement are guaranteed by Matador, the parent corporation. Various commodity hedging agreements with certain of the lenders under the Credit Agreement (or affiliates thereof) are also secured by the collateral of and guaranteed by certain eligible subsidiaries of MRC Energy Company.

The borrowing base under the Credit Agreement is determined semi-annually as of May 1 and November 1 by the lenders based primarily on the estimated value of the Company's proved oil and natural gas reserves at December 31 and June 30 of each year, respectively. Both the Company and the lenders may request an unscheduled redetermination of the borrowing base once each between scheduled redetermination dates. During the second quarter of 2015, the lenders completed their review of the Company's proved oil and natural gas reserves at December 31, 2014, and as a result, on April 6, 2015, the Company received notice that the borrowing base would be reaffirmed at $450.0 million and the conforming borrowing base would be reaffirmed at $375.0 million. Pursuant to an amendment to the Credit Agreement entered into concurrently with the issuance of $400.0 million of senior unsecured notes on April 14, 2015 discussed herein, the borrowing base was reduced to the conforming borrowing base of $375.0 million. During October 2015, the lenders completed their review of the Company's estimated total proved oil and natural gas reserves at June 30, 2015, and as a result the Company amended the Credit Agreement to reaffirm the borrowing base at $375.0 million and extend the maturity date to October 16, 2020. This October 2015 redetermination constituted the regularly scheduled November 1 redetermination.

In the event of a borrowing base increase, the Company is required to pay a fee to the lenders equal to a percentage of the amount of the increase, which is determined based on market conditions at the time of the borrowing base increase. Total deferred loan costs were $1.8 million at December 31, 2015, and these costs are being amortized over the term of the Credit Agreement, which approximates amortization of these costs using the effective interest method. If, upon a redetermination or the automatic reduction of the borrowing base to the conforming borrowing base, the borrowing base were to be less than the outstanding borrowings under the Credit Agreement at any time, the Company would be required to provide additional collateral satisfactory in nature and value to the lenders to increase the borrowing base to an amount sufficient to cover such excess or to repay the deficit in equal installments over a period of six months.

At December 31, 2015, the Company had no borrowings outstanding under the Credit Agreement and approximately $0.6 million in outstanding letters of credit issued pursuant to the Credit Agreement. During the year ended December 31, 2015 using a portion of the net proceeds from the senior unsecured notes offering and public offering of our common stock discussed herein, the Company repaid a total of $465.0 million of its outstanding borrowings under the Credit Agreement. At February 25, 2016, the Company continued to have no borrowings outstanding under the Credit Agreement and approximately $0.6 million in outstanding letters of credit issued pursuant to the Credit Agreement.

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — CONTINUED
December 31, 2015, 2014 and 2013

NOTE 6 — DEBT — Continued

Borrowings under the Credit Agreement may be in the form of a base rate loan or a Eurodollar loan. If the Company borrows funds as a base rate loan, such borrowings will bear interest at a rate equal to the higher of (i) the prime rate for such day or (ii) the Federal Funds Effective Rate (as defined in the Credit Agreement) on such day, plus 0.50% or (iii) the daily adjusting LIBOR rate (as defined in the Credit Agreement) plus 1.0% plus, in each case, an amount from 0.50% to 1.50% of such outstanding loan depending on the level of borrowings under the agreement. If the Company borrows funds as a Eurodollar loan, such borrowings will bear interest at a rate equal to (i) the quotient obtained by dividing (A) the LIBOR rate by (B) a percentage equal to 100% minus the maximum rate during such interest calculation period at which Royal Bank of Canada ("RBC") is required to maintain reserves on Eurocurrency Liabilities (as defined in Regulation D of the Board of Governors of the Federal Reserve System) plus (ii) an amount from 1.50% to 2.50% of such outstanding loan depending on the level of borrowings under the Credit Agreement. The interest period for Eurodollar borrowings may be one, two, three or six months as designated by the Company.

A commitment fee of 0.375% to 0.50%, depending on the unused availability under the Credit Agreement, is also paid quarterly in arrears. The Company includes this commitment fee, any amortization of deferred financing costs (including origination, borrowing base increase and amendment fees) and annual agency fees, if any, as interest expense and in its interest rate calculations and related disclosures. The Credit Agreement requires the Company to maintain a debt to EBITDA ratio, which is defined as total debt outstanding divided by a rolling four quarter EBITDA calculation, of 4.25 or less.

Subject to certain exceptions, the Credit Agreement contains various covenants that limit the Company's ability to take certain actions, including, but not limited to, the following:

- incur indebtedness or grant liens on any of the Company's assets;
- enter into commodity hedging agreements;
- declare or pay dividends, distributions or redemptions;
- merge or consolidate;
- make any loans or investments;
- engage in transactions with affiliates; and
- engage in certain asset dispositions, including a sale of all or substantially all of the Company's assets; and
- take certain actions with respect to the Company's senior unsecured notes.

If an event of default exists under the Credit Agreement, the lenders will be able to accelerate the maturity of the borrowings and exercise other rights and remedies. Events of default include, but are not limited to, the following events:

- failure to pay any principal or interest on the outstanding borrowings or any reimbursement obligation under any letter of credit when due or any fees or other amounts within certain grace periods;
- failure to perform or otherwise comply with the covenants and obligations in the Credit Agreement or other loan documents, subject, in certain instances, to certain grace periods;
- bankruptcy or insolvency events involving the Company or its subsidiaries; and
- a change of control, as defined in the Credit Agreement.

At December 31, 2015, the Company believes that it was in compliance with the terms of its Credit Agreement.

Senior Unsecured Notes

On April 14, 2015, Matador issued $400.0 million of 6.875% senior notes due 2023 (the "Original Notes") in a private placement. The Original Notes are Matador's senior unsecured obligations, are redeemable as described below and were issued at par value. The net proceeds were used to pay down a portion of the outstanding borrowings under the Credit Agreement and the debt assumed in connection with the HEYCO Merger. The Original Notes mature on April 15, 2023, and interest is payable semi-annually in arrears on April 15 and October 15 of each year.

On October 21, 2015, and pursuant to a registered exchange offer, the Company exchanged all of the privately placed Original Notes for a like principal amount of 6.875% senior notes due 2023 that have been registered under the Securities Act (the “Registered Notes” or the “Notes”). The terms of such Notes are substantially the same as the terms of the Original Notes

NOTE 6 — DEBT — Continued

except that the transfer restrictions, registration rights and provisions for additional interest relating to the Original Notes do not apply to the Notes.

On or after April 15, 2018, Matador may redeem all or a portion of the Notes at any time or from time to time at the following redemption prices (expressed as percentages of the principal amount) plus accrued and unpaid interest, if any, to the applicable redemption date, if redeemed during the twelve month period beginning on April 15 of the years indicated.

Year	Redemption Price
2018	105.156%
2019	103.438%
2020	101.719%
2021 and thereafter	100.000%

At any time prior to April 15, 2018, Matador may redeem up to 35% of the aggregate principal amount of the Notes with net proceeds from certain equity offerings at a redemption price of 106.875% of the principal amount of the Notes, plus accrued and unpaid interest, if any, to the redemption date; provided that (i) at least 65% in aggregate principal amount of the Notes (including any additional notes) originally issued remains outstanding immediately after the occurrence of such redemption (excluding Notes held by Matador and its subsidiaries) and (ii) each such redemption occurs within 180 days of the date of the closing of the related equity offering.

In addition, at any time prior to April 15, 2018, Matador may redeem all or part of the Notes at a redemption price equal to the sum of (i) the principal amount thereof, plus (ii) the excess, if any, of (a) the present value at such time of (1) the redemption price of such Notes at April 15, 2018 plus (2) any required interest payments due on such Notes through April 15, 2018 discounted to the redemption date on a semi-annual basis using a discount rate equal to the Treasury Rate (as defined in the indenture governing the Notes (the “Indenture”)) plus 50 basis points, over (b) the principal amount of such Notes, plus (iii) accrued and unpaid interest, if any, to the redemption date.

Subject to certain exceptions, the Indenture contains various covenants that limit the Company’s ability to take certain actions, including, but not limited to, the following:

- incur or guarantee additional debt or issue certain types of preferred stock;
- pay dividends on capital stock or redeem, repurchase or retire its capital stock or subordinated indebtedness;
- transfer or sell assets;
- make certain investments;
- create certain liens;
- enter into agreements that restrict dividends or other payments from its Restricted Subsidiaries (as defined in the Indenture) to the Company;
- consolidate, merge or transfer all or substantially all of its assets;
- engage in transactions with affiliates; and
- create unrestricted subsidiaries.

In the case of an event of default arising from certain events of bankruptcy or insolvency with respect to Matador, any Restricted Subsidiary that is a Significant Subsidiary (as defined in the Indenture) or any group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary, all outstanding 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 Notes may declare all the Notes to be due and payable immediately. Events of default include, but are not limited to, the following events:

- default for 30 days in the payment when due of interest on the Notes;
- default in the payment when due of the principal of, or premium, if any, on the Notes;

F-19

NOTE 6 — DEBT — Continued

- failure by Matador to comply with its obligations to offer to purchase or purchase Notes when required pursuant to the change of control or asset sale provisions of the Indenture or Matador’s failure to comply with the covenant relating to merger, consolidation or sale of assets;
- failure by Matador for 180 days after notice to comply with its reporting obligations under the Indenture;
- failure by Matador for 60 days after notice to comply with any of the other agreements in the Indenture;
- payment defaults and accelerations with respect to other indebtedness of Matador and its Restricted Subsidiaries in the aggregate principal amount of $25.0 million or more;
- failure by Matador or any Restricted Subsidiary to pay certain final judgments aggregating in excess of $25.0 million within 60 days;
- any subsidiary guarantee by a guarantor ceases to be in full force and effect, is declared null and void in a judicial proceeding or is denied or disaffirmed by its maker; and
- certain events of bankruptcy or insolvency with respect to Matador or any Restricted Subsidiary that is a Significant Subsidiary or any group of Restricted Subsidiaries that, taken together, would constitute a Significant Subsidiary.

Note Payable

In connection with the HEYCO Merger, the Company assumed a note payable to PlainsCapital Bank in the amount of $12.5 million pursuant to which approximately $12.0 million of indebtedness was outstanding. The outstanding indebtedness was repaid on April 14, 2015 using a portion of the net proceeds from the Notes offering, and the related credit agreement and all associated obligations were terminated.

Table of Contents

Matador Resources Company and Subsidiaries
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — CONTINUED
December 31, 2015, 2014 and 2013
NOTE 7 — INCOME TAXES

Deferred tax assets and liabilities are the result of temporary differences between the financial statement carrying values and the tax bases of assets and liabilities. The Company's net deferred tax position as of December 31, 2015 and 2014, respectively, is as follows (in thousands).

	December 31, 2015	2014
Deferred tax assets		
Net operating loss carryforwards	$79,208	$88,447
Alternative minimum tax carryforward	9,785	7,197
Percentage depletion carryover	2,442	2,068
Property and equipment	42,757	113
Deferred gain on sale leaseback transaction	32,831	—
Other	7,396	281
Total deferred tax assets	174,419	98,106
Valuation allowance on deferred tax assets	(154,320)	—
Total deferred tax assets, net of valuation allowance	20,099	98,106
Deferred tax liabilities		
Unrealized gain on derivatives	(5,699)	(20,145)
Property and equipment	—	(145,620)
Other	(14,400)	(5,875)
Total deferred tax liabilities	(20,099)	(171,640)
Net deferred tax liabilities	$—	$(73,534)

The Company reported a net loss for the year ended December 31, 2015. The Company had an effective tax rate of 36.8% for the year ended December 31, 2014. Total income tax expense for the year ended December 31, 2014 differed from amounts computed by applying the U.S. federal statutory rates to pre-tax income primarily due to the impact of state income taxes.

At December 31, 2015, the Company had net operating loss carryforwards of $212.5 million for federal income tax purposes and $4.8 million for state income tax purposes available to offset future taxable income, as limited by the applicable provisions, and which expire at various dates beginning December 31, 2027 for the federal net operating loss carryforwards. The state net operating loss carryforwards began expiring at various dates beginning December 31, 2013 for the state of New Mexico; however, the significant portion of the Company's state net operating loss carryforwards expire beginning in 2027.

As a result of the net capitalized costs of the Company's oil and natural gas properties less related deferred income taxes exceeding the full-cost ceiling during the year ended December 31, 2015, the Company recorded an impairment charge of $801.2 million, exclusive of tax effect, to the net capitalized costs of its oil and natural gas properties. At December 31, 2015, the Company's deferred tax assets exceeded its deferred tax liabilities due to the deferred tax assets generated by the impairment charges recorded; as a result, the Company established a valuation allowance of $154.3 million against the Company's federal and state deferred tax assets. The valuation allowance will continue to be recognized until the realization of future tax benefits are more likely than not to be utilized.

No impairment to the net carrying value of the Company's oil and natural gas properties and no corresponding charge resulting from a full-cost ceiling impairment was recorded during the year ended December 31, 2014.

At March 31, 2013, the net capitalized costs of the Company's oil and natural gas properties less related deferred income taxes exceeded the full-cost ceiling. As a result, the Company recorded an impairment charge of $21.2 million, exclusive of tax effect, to the net capitalized costs of its oil and natural gas properties. This charge is reflected in the Company's consolidated statement of operations for the year ended December 31, 2013.

Table of Contents

Matador Resources Company and Subsidiaries
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — CONTINUED
December 31, 2015, 2014 and 2013
NOTE 7 — INCOME TAXES — Continued

The income tax expense reconciled to the tax computed at the statutory federal rate for the years ended December 31, 2015, 2014 and 2013, respectively, is as follows (in thousands).

	Year Ended December 31,		
	2015	2014	2013
Current income tax provision			
State income tax	$371	$—	$—
Federal alternative minimum tax	2,588	133	404
Net current income tax provision	2,959	133	404
Deferred income tax provision (benefit)			
Federal tax expense at statutory rate [1]	(289,412)	61,301	19,177
State income tax	(13,215)	2,707	431
Permanent differences [2]	698	397	319
Federal alternative minimum tax	(2,588)	(133)	(404)
Change in federal valuation allowance	145,777	—	(8,885)
Change in state valuation allowance	8,413	(30)	(1,345)
Net deferred income tax (benefit) provision	(150,327)	64,242	9,293
Total income tax (benefit) provision	$(147,368)	$64,375	$9,697

(1) The statutory federal tax rate was 35% for the years ended December 31, 2015, 2014 and 2013.
(2) Amount is primarily attributable to stock-based compensation.

The Company files a United States federal income tax return and several state tax returns, a number of which remain open for examination. The earliest tax year open for examination for the federal, the state of New Mexico and the state of Louisiana tax returns is 2012. The earliest tax year open for examination by the state of Texas is 2009. During the year ended December 31, 2015, the Company's 2009 and 2010 franchise tax returns were under examination by the state of Texas. This examination has been completed with no additional tax due; however, the examination has not been formally closed. In addition, as of December 31, 2015, the Company's 2013 federal income tax return was under examination by the Internal Revenue Service. This examination is in the preliminary stage and no additional income taxes or refunds of previous tax payments for 2013 had been recorded as a result of this examination at December 31, 2015.

The Company has evaluated all tax positions for which the statute of limitations remains open and believes that the material positions taken would more likely than not be sustained by examination. Therefore, at December 31, 2015, the Company had not established any reserves for, nor recorded any unrecognized benefits related to, uncertain tax positions.

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — CONTINUED
December 31, 2015, 2014 and 2013

NOTE 8 — STOCK-BASED COMPENSATION

Stock Options, Restricted Stock, Restricted Stock Units, Stock and Performance Awards

In 2003, the Company's Board of Directors and shareholders approved the 2003 Stock and Incentive Plan (the "2003 Plan"). The 2003 Plan, as amended, provided that a maximum of 3,481,569 shares of common stock in the aggregate could be issued pursuant to options or restricted stock grants. The persons eligible to receive awards under the 2003 Plan included employees, directors, contractors or advisors of the Company.

In 2012, the Board of Directors adopted and shareholders approved the 2012 Long-Term Incentive Plan (the "2012 Incentive Plan"). The 2012 Incentive Plan provided for a maximum of 4,000,000 shares of common stock in the aggregate that may be issued by the Company pursuant to grants of stock options, restricted stock, stock appreciation rights, restricted stock units or other performance awards. The persons eligible to receive awards under the 2012 Incentive Plan include employees, directors, contractors or advisors of the Company. The 2012 Incentive Plan was amended and restated and approved by the Company's shareholders at its Annual Meeting of Shareholders on June 10, 2015. Among other things, this amendment increased the maximum number of shares of common stock issuable by the Company pursuant to grants of awards to 8,700,000. The primary purpose of the 2012 Incentive Plan is to attract and retain key employees, key contractors and outside directors and advisors of the Company. With the adoption of the 2012 Incentive Plan, the Company does not plan to make any future awards under the 2003 Plan, but the 2003 Plan will remain in place until all awards outstanding under that plan have been settled.

The 2003 Plan and the 2012 Incentive Plan are administered by the independent members of the Board of Directors, which, upon recommendation of the Nominating, Compensation and Planning Committee, determines the number of options, restricted shares or other awards to be granted, the effective dates, the terms of the grants and the vesting periods. The Company typically uses newly issued shares of common stock to satisfy option exercises or restricted share grants. All stock-based compensation awards granted since 2012 have been granted under the 2012 Incentive Plan and are equity-based awards for which the fair value is fixed at the grant date, while all stock-based compensation awards granted prior to January 1, 2012 were granted under the 2003 Plan and are liability-based awards for which the fair value is remeasured at each reporting period.

Stock Options

Historically, stock option awards have been granted to purchase the Company's common stock at an exercise price equal to the fair market value on the date of grant, a typical vesting period of three or four years and a typical maximum term of five or ten years.

The fair value of stock option awards outstanding under the 2003 Plan was estimated using the following weighted average assumptions at December 31, 2015, 2014 and 2013.

	2015	2014	2013
Stock option pricing model	Black Scholes Merton	Black Scholes Merton	Black Scholes Merton
Expected option life	0.39 years	1.51 years	2.44 years
Risk-free interest rate	0.64%	0.74%	0.69%
Volatility	91.98%	55.14%	51.51%
Dividend yield	—%	—%	—%
Estimated forfeiture rate	—%	—%	0.79%

NOTE 8 — STOCK-BASED COMPENSATION — Continued

The weighted average grant date fair value for stock option awards outstanding under the 2012 Incentive Plan was estimated using the following weighted average assumptions during the years ended December 31, 2015, 2014 and 2013.

	2015	2014	2013
Stock option pricing model	Black Scholes Merton	Black Scholes Merton	Black Scholes Merton
Expected option life	4.00 years	3.99 years	4.00 years
Risk-free interest rate	1.15%	1.21%	0.69%
Volatility	56.89%	51.47%	58.65%
Dividend yield	—%	—%	—%
Estimated forfeiture rate	3.21%	4.28%	6.37%
Weighted average fair value of stock option awards granted during the year	$9.90	$9.45	$3.91

The Company estimated the future volatility of its common stock using the historical value of its peer group for a period of time commensurate with the expected term of the stock option due to the lack of historical trading data available for its common stock. The expected term was estimated using the simplified method outlined in Staff Accounting Bulletin Topic 14. The risk free interest rate is the rate for constant yield U.S. Treasury securities with a term to maturity that is consistent with the expected term of the award.
Summarized information about stock options outstanding at December 31, 2015 under the 2003 Plan and the 2012 Incentive Plan is as follows.

	Number of options (in thousands)	Weighted average exercise price
Options outstanding at December 31, 2014	1,798	$12.47
Options granted	797	$22.32
Options exercised	(85)	$9.32
Options forfeited	(147)	$20.55
Options outstanding at December 31, 2015	2,363	$15.40

	Options outstanding at December 31, 2015			Options exercisable at December 31, 2015	
Range of exercise prices	Shares outstanding (in thousands)	Weighted average remaining contractual life	Weighted average exercise price	Shares exercisable (in thousands)	Weighted average exercise price
$8.18 - $9.90	848	2.31	$8.33	432	$8.41
$10.39 - $17.80	394	1.35	$10.64	197	$10.64
$18.77 - $22.66	837	3.95	$21.83	5	$18.77
$23.40 - $27.33	284	3.26	$24.22	—	$—

At December 31, 2015, the aggregate intrinsic value was $13.3 million for outstanding options and $6.7 million for exercisable options, based on the Company’s quoted closing market price of $19.77 per share on that date. The remaining weighted average contractual term of exercisable options at December 31, 2015 was 2.21 years.
The total intrinsic value of options exercised during the years ended December 31, 2015, 2014 and 2013 was $1.3 million, $0.2 million and $36,000, respectively. The tax related benefit realized from the exercise of stock options

totaled $0.3 million, $0.1 million and zero for the years ended December 31, 2015, 2014 and 2013, respectively. During the years ended December 31, 2015, 2014 and 2013, the Company recognized $4.7 million, $2.5 million and $2.2 million, respectively, in stock-based compensation expense attributable to stock options. At December 31, 2015, 2014 and 2013, the Company had recorded zero, $1.4 million and $1.2 million of long-term liabilities and $1.0 million, zero and $0.1

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — CONTINUED
December 31, 2015, 2014 and 2013

NOTE 8 — STOCK-BASED COMPENSATION — Continued

million of current liabilities, respectively, related to its outstanding liability-based stock options. The Company did not settle any liability-based awards in cash for the years ended December 31, 2015, 2014 and 2013, respectively.

At December 31, 2015, the total remaining unrecognized compensation expense related to unvested stock options was approximately $8.5 million and the weighted average remaining requisite service period (vesting period) of all unvested stock options was 1.81 years.

The fair value of options vested during 2015, 2014 and 2013 was $1.3 million, $1.5 million and $0.3 million, respectively.

Restricted Stock, Restricted Stock Units and Common Stock

The Company has granted stock, restricted stock and restricted stock unit awards to employees, outside directors and advisors of the Company under the 2003 Plan and the 2012 Incentive Plan. The stock and restricted stock are issued upon grant, with the restrictions, if any, being removed upon vesting. The restricted stock units are issued upon vesting, unless the recipient makes an election to defer issuance for a term no longer than two years after vesting. No such elections were made with respect to the 2012 restricted stock unit awards; one current director elected to defer the issuance of his awards in 2014 and 2013. All awards granted in 2015, 2014 and 2013 were service based awards and vest over the service period which is one to four years. All restricted stock and restricted stock unit awards outstanding at December 31, 2015 were granted under the 2012 Incentive Plan.

Restricted stock awards granted in 2012 included 116,841 shares of performance based restricted stock and 116,841 performance based restricted stock units with a combined weighted average fair value of $13.24 per combined share and unit. These awards vested based on the outcome of the Company’s total shareholder return over a three-year period beginning March 19, 2012 and ending April 15, 2015 as compared to a designated peer group. These awards resulted in the vesting of an aggregate of 96,590 shares of restricted stock in addition to 96,590 restricted stock units. The remaining shares of restricted stock and restricted stock units were forfeited.

A summary of the non-vested restricted stock and restricted stock units as of December 31, 2015 is presented below (in thousands, except fair value).

	Restricted Stock				Restricted Stock Units			
	Service Based		Performance Based		Service Based		Performance Based	
Non-vested restricted stock and restricted stock units	Shares	Weighted average fair value	Shares	Weighted average fair value[1]	Shares	Weighted average fair value	Shares	Weighted average fair value[1]
Non-vested at December 31, 2014	569	$14.03	97	$13.24	71	$16.28	97	$—
Granted	430	$22.51	—	—	36	$24.58	—	—
Vested	(8)	$15.03	(97)	—	(39)	$14.02	(97)	—
Forfeited	(137)	$18.08	—	—	—	—	—	—
Non-vested at December 31, 2015	854	$17.64	—	$13.24	68	$21.89	—	$—

(1) The fair value of these restricted stock units is reflected in the fair value of the performance based restricted stock, which was estimated based on the most likely outcome of the award as determined by the Monte Carlo method.

At December 31, 2015, the aggregate intrinsic value for the restricted stock and restricted stock units outstanding was $18.2 million as calculated based on the maximum number of shares of restricted stock and restricted stock units vesting, using the stock price on December 31, 2015.

During the years ended December 31, 2015, 2014 and 2013, the Company recognized approximately $4.7 million, $3.0 million and $1.6 million, respectively, in stock-based compensation expense attributable to restricted stock and restricted stock units.

NOTE 8 — STOCK-BASED COMPENSATION — Continued

At December 31, 2015, the total remaining unrecognized compensation expense related to unvested restricted stock and restricted stock units was approximately $10.3 million and the weighted average remaining requisite service period (vesting period) of all non-vested restricted stock and restricted stock units was 1.6 years.

The fair value of restricted stock and restricted stock units vested during 2015, 2014 and 2013 was $0.8 million, $0.9 million and $0.2 million, respectively.

The total tax benefit recognized for all stock-based compensation was $3.4 million, $1.9 million and $1.1 million for the years ended December 31, 2015, 2014 and 2013, respectively.

In February 2016, the Company granted awards of 243,428 shares of restricted stock and options to purchase 608,287 shares of the Company’s common stock at an exercise price of $15.00 per share to certain of its employees. The fair value of these awards was approximately $7.0 million. All of these awards cliff vest in three years.

NOTE 9 — EMPLOYEE BENEFIT PLANS

401(k) Plan

All full-time Company employees are eligible to join the Company’s defined contribution retirement plan the first day of the calendar month immediately following their date of employment. Each employee may contribute up to the maximum allowable under the Internal Revenue Code. Each year, the Company makes a contribution to the plan which equals 3% of the employee’s annual compensation, referred to as the Employer’s Safe Harbor Non-Elective Contribution, which totaled approximately $0.6 million, $0.4 million and $0.2 million in 2015, 2014 and 2013, respectively. In addition, each year, the Company may make a discretionary matching contribution, as well as additional contributions. The Company’s discretionary matching contributions totaled $0.8 million, $0.5 million and $0.3 million in 2015, 2014 and 2013, respectively. The Company made no additional discretionary contributions in any reporting period presented.

NOTE 10 — EQUITY

Stock Offerings, Retirement and Issuances

As discussed in Note 5, the Company issued 3,300,000 shares of common stock and 150,000 shares of a new series of Series A Preferred Stock to HEYCO Energy Group, Inc. in connection with the HEYCO Merger. Pursuant to the statement of resolutions, each share of Series A Preferred Stock would automatically convert into ten shares of Matador common stock, subject to customary anti-dilution adjustments, upon the vote and approval by Matador’s shareholders of an amendment to Matador’s Amended and Restated Certificate of Formation to increase the number of shares of authorized Matador common stock.

On April 2, 2015, the shareholders of the Company approved an amendment to the Company’s Amended and Restated Certificate of Formation that authorized an increase in the number of authorized shares of common stock from 80,000,000 shares to 120,000,000 shares. Following such approval, the 150,000 outstanding shares of Series A Preferred Stock converted to 1,500,000 shares of common stock on April 6, 2015. Pursuant to the terms of the HEYCO Merger, 1,250,000 of the 1,500,000 shares were being held in escrow at December 31, 2015 to satisfy the post-closing adjustments to the merger consideration for title or environmental defects on the properties acquired in the merger.

On April 21, 2015, the Company completed a public offering of 7,000,000 shares of its common stock. After deducting offering costs totaling approximately $1.2 million, the Company received net proceeds of approximately $187.6 million. The Company used a portion of the net proceeds to repay $85.0 million in outstanding borrowings under the Credit Agreement (see Note 6), which amounts may be reborrowed in accordance with the terms of that facility. The remaining $102.6 million of net proceeds was used to fund a portion of the Company’s working capital expenditures, including the addition of a third drilling rig in the Delaware Basin in late July 2015 and targeted acquisitions of additional acreage in the Delaware Basin, as well as in the Eagle Ford shale and the Haynesville shale, and for other general working capital needs.

On May 29, 2014, the Company completed a public offering of 7,500,000 shares of its common stock. After deducting direct offering costs totaling approximately $0.6 million, the Company received net proceeds of approximately $181.3 million.

On September 10, 2013, the Company completed an underwritten public offering of 9,775,000 shares of its common stock, including 1,275,000 shares issued pursuant to the underwriters’ exercise of their option to purchase additional shares.

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — CONTINUED
December 31, 2015, 2014 and 2013

NOTE 10 — EQUITY— Continued

After deducting underwriting discounts, commissions and direct offering costs totaling approximately $7.4 million, the Company received net proceeds of approximately $141.7 million.

Treasury Stock

On October 30, 2015 and October 31, 2014, Matador's Board of Directors canceled all of the shares of treasury stock outstanding as of September 30, 2015 and September 30, 2014, respectively. These shares were restored to the status of authorized but unissued shares of common stock of the Company.

The 2,586 and 30,967 shares of treasury stock outstanding at December 31, 2015 and December 31, 2014, respectively, and the increase of 105,126 shares in treasury stock outstanding during the year ended December 31, 2013, represent forfeitures of non-vested restricted stock awards and forfeitures of fully vested restricted stock awards due to net share settlements with employees.

NOTE 11 — DERIVATIVE FINANCIAL INSTRUMENTS

From time to time, the Company uses derivative financial instruments to mitigate its exposure to commodity price risk associated with oil, natural gas and natural gas liquids prices. These instruments typically consist of put and call options in the form of costless collars or swap contracts. The Company records derivative financial instruments on its consolidated balance sheets as either assets or liabilities measured at fair value. The Company has elected not to apply hedge accounting for its existing derivative financial instruments. As a result, the Company recognizes the change in derivative fair value between reporting periods currently in its consolidated statements of operations as an unrealized gain or loss. The fair value of the Company's derivative financial instruments is determined using industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value of money and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. The Company has evaluated and considered the credit standings of its counterparties in determining the fair value of its derivative financial instruments.

The Company has entered into various costless collar contracts to mitigate its exposure to fluctuations in oil and natural gas prices, each with an established price floor and ceiling. For each calculation period, the specified price for determining the realized gain or loss pursuant to any oil contract is the arithmetic average of the settlement prices for the NYMEX West Texas Intermediate oil futures contract for the first nearby month corresponding to the calculation period's calendar month, and for any natural gas contract is the settlement price for the NYMEX Henry Hub natural gas futures contract for the delivery month corresponding to the calculation period's calendar month for the settlement date of that contract period.

When the settlement price is below the price floor established by one or more of these collars, the Company receives from the counterparty an amount equal to the difference between the settlement price and the price floor multiplied by the contract oil or natural gas volume. When the settlement price is above the price ceiling established by one or more of these collars, the Company pays to the counterparty an amount equal to the difference between the settlement price and the price ceiling multiplied by the contract oil or natural gas volume.

At December 31, 2015, the Company had various costless collar contracts open and in place to mitigate its exposure to oil and natural gas price volatility, each with a specific term (calculation period), notional quantity (volume hedged) and price floor and ceiling. Each contract is set to expire at varying times during 2016.

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — CONTINUED
December 31, 2015, 2014 and 2013

NOTE 11 — DERIVATIVE FINANCIAL INSTRUMENTS — Continued

The following is a summary of the Company’s open costless collar contracts for oil and natural gas at December 31, 2015.

Commodity	Calculation Period	Notional Quantity (Bbl or MMBtu)	Weighted Average Price Floor ($/Bbl or $/MMBtu)	Weighted Average Price Ceiling ($/Bbl or $/MMBtu)	Fair Value of Asset (thousands)
Oil	01/01/2016 - 12/31/2016	1,560,000	$47.46	$74.64	$13,083
Natural Gas	01/01/2016 - 12/31/2016	8,400,000	$2.75	$3.80	3,201
Total open derivative financial instruments					$16,284

Subsequent to December 31, 2015, the Company entered into various costless collar contracts for oil and natural gas. The costless collar contracts for oil included approximately 600,000 Bbl in 2016 with a weighted average floor price of $35.00 per Bbl and a weighted average ceiling price of $43.23 per Bbl. The Company also entered into costless collar contracts for natural gas, which included approximately 3,300,000 MMBtu in 2016, with a weighted average floor price of $2.25 per MMBtu and a weighted average ceiling price of $2.90 per MMBtu, and approximately 7,200,000 MMBtu in 2017, with a weighted average floor price of $2.25 MMBtu and a weighted average ceiling price of $3.57 MMBtu.

These derivative financial instruments are subject to master netting arrangements; all but one counterparty allow for cross-commodity master netting provided the settlements dates for the commodities are the same. The Company does not present different types of commodities with the same counterparty on a net basis in its consolidated balance sheets. The following table presents the gross asset and liability fair values of the Company’s commodity price derivative financial instruments and the location of these balances in the consolidated balance sheets as of December 31, 2015 and December 31, 2014 (in thousands).

Derivative Instruments	Gross amounts recognized	Gross amounts netted in the consolidated balance sheets	Net amounts presented in the consolidated balance sheets
December 31, 2015			
Current assets	$16,767	$(483)	$16,284
Other assets	—	—	—
Current liabilities	(483)	483	—
Other liabilities	—	—	—
Total	$16,284	$—	$16,284
December 31, 2014			
Current assets	$56,255	$(706)	$55,549
Other assets	—	—	—
Current liabilities	(706)	706	—
Other liabilities	—	—	—
Total	$55,549	$—	$55,549

Table of Contents

Matador Resources Company and Subsidiaries
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — CONTINUED
December 31, 2015, 2014 and 2013

NOTE 11 — DERIVATIVE FINANCIAL INSTRUMENTS — Continued

The following table summarizes the location and aggregate fair value of all derivative financial instruments recorded in the consolidated statements of operations for the periods presented (in thousands). These derivative financial instruments are not designated as hedging instruments.

Type of Instrument	Location in Statement of Operations	Year Ended December 31, 2015	2014	2013
Derivative Instrument				
Oil	Revenues: Realized gain (loss) on derivatives	$62,259	$5,221	$(2,408)
Natural Gas	Revenues: Realized gain (loss) on derivatives	12,653	(718)	831
Natural Gas Liquids (NGL)	Revenues: Realized gain on derivatives	2,182	519	668
Realized gain (loss) on derivatives		77,094	5,022	(909)
Oil	Revenues: Unrealized (loss) gain on derivatives	(31,897)	47,178	(5,319)
Natural Gas	Revenues: Unrealized (loss) gain on derivatives	(5,440)	9,087	(1,580)
Natural Gas Liquids (NGL)	Revenues: Unrealized (loss) gain on derivatives	(1,928)	2,037	(333)
Unrealized (loss) gain on derivatives		(39,265)	58,302	(7,232)
Total		$37,829	$63,324	$(8,141)

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — CONTINUED
December 31, 2015, 2014 and 2013

NOTE 12 — FAIR VALUE MEASUREMENTS

The Company measures and reports certain financial and non-financial assets and liabilities on a fair value basis. Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). Fair value measurements are classified and disclosed in one of the following categories.

Level 1	Unadjusted quoted prices for identical, unrestricted assets or liabilities in active markets.
Level 2	Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that are valued with industry standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value of money and (iii) current market and contractual prices for the underlying instruments, as well as other relevant economic measures. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument and can be derived from observable data or supported by observable levels at which transactions are executed in the marketplace.
Level 3	Unobservable inputs that are not corroborated by market data which reflect a company’s own market assumptions.

Financial and non-financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The assessment of the significance of a particular input to the fair value measurement requires judgment, which may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels.

At December 31, 2015 and 2014, the carrying values reported on the consolidated balance sheets for accounts receivable, prepaid expenses, accounts payable, accrued liabilities, royalties payable, amounts due to affiliates, advances from joint interest owners, amounts due to joint ventures, income taxes payable and other current liabilities approximate their fair values due to their short-term maturities.

At December 31, 2015 and 2014, the carrying value of borrowings under the Credit Agreement approximates fair value as it is subject to short-term floating interest rates that reflect market rates available to the Company at the time and is classified at Level 2.

At December 31, 2015, the fair value of the Company’s Notes was $381.0 million based on quoted market prices, which represents Level 1 inputs in the fair value hierarchy. The Company had no Notes outstanding at December 31, 2014.

The following tables summarize the valuation of the Company’s financial assets and liabilities that were accounted for at fair value on a recurring basis in accordance with the classifications provided above as of December 31, 2015 and 2014 (in thousands).

Description	Fair Value Measurements at December 31, 2015 using			
	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Oil and natural gas derivatives	$—	$16,284	$—	$16,284
Total	$—	$16,284	$—	$16,284

Description	Fair Value Measurements at December 31, 2014 using			
	Level 1	Level 2	Level 3	Total
Assets (Liabilities)				
Oil and natural gas derivatives	$—	$55,549	$—	$55,549
Total	$—	$55,549	$—	$55,549

Additional disclosures related to derivative financial instruments are provided in Note 11. For purposes of fair value measurement, the Company determined that derivative financial instruments (e.g., oil, natural gas and NGL derivatives) should be classified as Level 2 in the fair value hierarchy.

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — CONTINUED
December 31, 2015, 2014 and 2013

NOTE 12 — FAIR VALUE MEASUREMENTS — Continued

Certain assets and liabilities are measured at fair value on a nonrecurring basis, including assets and liabilities acquired in a business combination (see Note 5), lease and well equipment inventory when the market value is determined to be lower than the cost of the inventory and other property and equipment that are reduced to fair value when they are impaired or held for sale. The Company recorded no impairment to its lease and well equipment inventory or other property and equipment in 2015 and 2014. The Company determined the value of the lease and well equipment inventory using Level 3 inputs and assumptions.

NOTE 13 — COMMITMENTS AND CONTINGENCIES

Office Lease

The Company's corporate headquarters are located at One Lincoln Centre, 5400 LBJ Freeway, Suite 1500, Dallas, Texas 75240. In June 2015, the Company entered into the seventh amendment to its office lease agreement. This amendment increased the square footage of its corporate headquarters to approximately 100,000 square feet effective January 1, 2016. The lease expires during 2026. The base rate escalates during the course of the lease; however, the Company recognizes rent expense ratably over the term of the lease.

From time to time, the Company also enters into leases for field offices in locations where it has active field operations. These leases are typically for terms of less than five years and are not considered principal properties.

The following is a schedule of future minimum lease payments required under all office lease agreements as of December 31, 2015 (in thousands).

Year Ending December 31,	Amount
2016	$2,017
2017	2,432
2018	2,488
2019	2,528
2020	2,602
Thereafter	14,995
Total	$27,062

Rent expense, including fees for operating expenses and consumption of electricity, was $1.7 million, $0.9 million and $0.8 million for 2015, 2014 and 2013, respectively.

Natural Gas and NGL Processing and Transportation Commitments

Effective September 1, 2012, the Company entered into a firm five-year natural gas processing and transportation agreement whereby the Company committed to transport the anticipated natural gas production from a significant portion of its Eagle Ford acreage in South Texas through the counterparty's system for processing at the counterparty's facilities. The agreement also includes firm transportation of the natural gas liquids extracted at the counterparty's processing plant downstream for fractionation. After processing, the residue natural gas is purchased by the counterparty at the tailgate of its processing plant and further transported under its natural gas transportation agreements. The arrangement contains fixed processing and liquids transportation and fractionation fees, and the revenue the Company receives varies with the quality of natural gas transported to the processing facilities and the contract period.

Under this agreement, if the Company does not meet 80% of the maximum thermal quantity transportation and processing commitments in a contract year, it will be required to pay a deficiency fee per MMBtu of natural gas deficiency. Any quantity in excess of the maximum MMBtu delivered in a contract year can be carried over to the next contract year for purposes of calculating the natural gas deficiency. During certain prior periods, the Company had an immaterial natural gas deficiency, and the counterparty to this agreement waived the deficiency fee. The Company paid approximately $5.5 million and $5.8 million in processing and transportation fees under this agreement during the years ended December 31, 2015 and 2014, respectively. The future undiscounted minimum payments under this agreement as of December 31, 2015 are $1.8 million in 2016 and $1.2 million in 2017.

As part of the sale of the Loving County System (see Note 5), the Company entered into a 15-year fixed-fee natural gas gathering and processing agreement whereby the Company committed to deliver the anticipated natural gas production from a significant portion of its Loving County, Texas acreage in West Texas through the counterparty’s gathering system for

NOTE 13 — COMMITMENTS AND CONTINGENCIES — Continued

processing at the counterparty's facility. Under this agreement, if the Company does not meet the volume commitment for transportation and processing at the facility in a contract year, it will be required to pay a deficiency fee per MMBtu of natural gas deficiency. At the end of each year of the agreement, the Company can elect to have the previous year's actual transportation and processing volumes be the new minimum commitment for each of the remaining years of the contract. As such, the Company has the ability to unilaterally reduce the transportation and processing commitment if the Company's production in the Loving County area is less than the Company's currently projected production. If the Company ceased operations in this area at December 31, 2015, the total deficiency fee required to be paid would be approximately $9.6 million. In addition, if the Company elects to reduce the transportation and processing commitment in any year, the Company has the ability to elect to increase the committed volumes in any future year to the originally agreed transportation and processing commitment. Any quantity in excess of the volume commitment delivered in a contract year can be carried over to the next contract year for purposes of calculating the natural gas deficiency. The Company paid approximately $1.8 million in processing and transportation fees under this agreement during the year ended December 31, 2015. The Company can elect to either sell the residue gas to the counterparty at the tailgate of its processing plant or have the counterparty deliver to the Company the residue gas in-kind to be sold to third parties downstream of the plant.

Other Commitments

The Company does not own or operate its own drilling rigs, but instead enters into contracts with third parties for such drilling rigs. These contracts establish daily rates for the drilling rigs and the term of the Company's commitment for the drilling services to be provided, which have typically been for one year or less, although the Company has entered into longer-term contracts in order to secure new drilling rigs equipped with the latest technology in plays that were until recently experiencing heavy demand for drilling rigs. The Company would incur a termination obligation if the Company elected to terminate a contract and if the drilling contractor were unable to secure replacement work for the contracted drilling rigs or if the drilling contractor were unable to secure replacement work for the contracted drilling rigs at the same daily rates being charged to the Company prior to the end of their respective contract terms. The Company's undiscounted minimum outstanding aggregate termination obligations under its drilling rig contracts were approximately $43.5 million at December 31, 2015.

The Company entered into an agreement with a third party for the engineering, procurement, construction and installation of a natural gas processing plant in the Rustler Breaks prospect area in Eddy County, New Mexico in late 2015. This plant is expected to process a portion of the Company's natural gas produced from certain of its wells in the Delaware Basin, as well as third-party natural gas once the plant is completed. Total commitments under this contract are $28.5 million and the Company made payments totaling $7.0 million during the year ended December 31, 2015. The plant is scheduled to be completed and placed in service in the third quarter of 2016.

At December 31, 2015, the Company had outstanding commitments to participate in the drilling and completion of various non-operated wells. If all of these wells are drilled and completed as proposed, the Company's minimum outstanding aggregate commitments for its participation in these non-operated wells were approximately $5.7 million at December 31, 2015. The Company expects these costs to be incurred within the next year.

Legal Proceedings

The Company is a defendant in several lawsuits encountered in the ordinary course of its business. While the ultimate outcome and impact to the Company cannot be predicted with certainty, in the opinion of management, it is remote that these lawsuits will have a material adverse impact on the Company's financial condition, results of operations or cash flows.

Table of Contents
Matador Resources Company and Subsidiaries
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS — CONTINUED
December 31, 2015, 2014 and 2013
NOTE 14 — SUPPLEMENTAL DISCLOSURES

Accrued Liabilities
The following table summarizes the Company's current accrued liabilities at December 31, 2015 and 2014 (in thousands).

	December 31,	
	2015	2014
Accrued evaluated and unproved and unevaluated property costs	$54,586	$86,259
Accrued support equipment and facilities costs	17,393	4,290
Accrued lease operating expenses	7,743	9,034
Accrued interest on debt	5,806	206
Accrued asset retirement obligations	254	311
Accrued partners' share of joint interest charges	4,565	3,767
Other	2,022	3,489
Total accrued liabilities	$92,369	$107,356

Supplemental Cash Flow Information
The following table provides supplemental disclosures of cash flow information for the years ended December 31, 2015, 2014 and 2013 (in thousands).

	Year Ended December 31,		
	2015	2014	2013
Cash paid for interest expense, net of amounts capitalized	$16,154	$5,269	$5,801
Asset retirement obligations related to mineral properties	2,510	3,843	1,363
Asset retirement obligations related to support equipment and facilities	383	120	3
(Decrease) increase in liabilities for oil and natural gas properties capital expenditures	(30,683)	32,972	7,458
Increase in liabilities for support equipment and facilities	12,076	4,290	660
Issuance of restricted stock units for Board and advisor services	584	444	274
Issuance of common stock for Board and advisor services	24	16	57
Stock-based compensation expense recognized as liability	79	223	1,012
Transfer of inventory to oil and natural gas properties	615	216	343

NOTE 15 — SUBSIDIARY GUARANTORS
Matador filed a registration statement on Form S-3 with the SEC in 2013, which became effective on May 9, 2013, and a registration statement on Form S-3 with the SEC in 2014, which became effective upon filing on May 22, 2014, registering, in each case, among other securities, senior and subordinated debt securities and guarantees of debt securities by certain subsidiaries of Matador (the "Shelf Guarantor Subsidiaries"). On April 14, 2015, the Company issued the Original Notes (see Note 6), which are jointly and severally guaranteed by certain subsidiaries of Matador (the "Notes Guarantor Subsidiaries" and, together with the Shelf Guarantor Subsidiaries, the "Guarantor Subsidiaries") on a full and unconditional basis (except for customary release provisions). On June 1, 2015, Matador filed a registration statement on Form S-4 with the SEC in connection with the exchange of the Original Notes for the Registered Notes, including guarantees by each of the Notes Guarantor Subsidiaries. The Form S-4 was declared effective by the SEC on September 16, 2015. The Company completed the exchange of all the Original Notes for Registered Notes on October 21, 2015. At December 31, 2015, the Guarantor Subsidiaries are 100% owned by Matador, and any subsidiaries of Matador other than the Guarantor Subsidiaries are minor. Matador is a parent holding company and has no independent assets or operations, and there are no significant restrictions on the ability of Matador to obtain funds from the Guarantor Subsidiaries by dividend or loan.

Table of Contents

NOTE 16 — RELATED PARTY TRANSACTIONS

In June 2015, the Company entered into two joint ventures to develop certain leasehold interests held by certain affiliates (the “HEYCO Affiliates”) of HEYCO Energy Group, Inc., the former parent company of HEYCO. The HEYCO Affiliates are owned by George M. Yates, who is a member of the Company’s Board of Directors, and certain of his affiliates. Pursuant to the terms of the transaction, the HEYCO Affiliates contributed an aggregate of approximately 1,900 net acres, primarily in the same properties previously held by HEYCO, to the two newly-formed entities in exchange for a 50% interest in each entity. The Company has agreed to contribute an aggregate of approximately $14 million in exchange for the other 50% interest in both entities. As of December 31, 2015, the Company had contributed an aggregate of approximately $0.7 million to the two entities. The Company’s contributions will be used to fund future capital expenditures associated with the interests being acquired as well as to fund acquisitions of other non-operated acreage opportunities.

Additionally, substantially all of the oil production from the wells acquired in the HEYCO Merger was subject to pre-existing sales contracts with an entity owned by affiliates of HEYCO Energy Group, Inc. The Company recorded revenue of $1.1 million for oil sold pursuant to such contracts for the year ended December 31, 2015. Such contracts were terminated in the third quarter of 2015.

Table of Contents
Matador Resources Company and Subsidiaries
UNAUDITED SUPPLEMENTARY INFORMATION
December 31, 2015, 2014 and 2013

SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES
Costs Incurred
The following table summarizes costs incurred and capitalized by the Company in the acquisition, exploration and development of oil and natural gas properties for the years ended December 31, 2015, 2014 and 2013 (in thousands).

	Year Ended December 31,		
	2015	2014	2013
Property acquisition costs			
Proved	$16,524	$2,728	$176
Unproved and unevaluated	253,923	78,484	64,305
Exploration costs	122,495	156,178	99,104
Development costs (1)	305,495	372,982	209,956
Total costs incurred	$698,437	$610,372	$373,541

(1) Includes midstream-related development costs of approximately $77.9 million for the year ended December 31, 2015.

Property acquisition costs are costs incurred to purchase, lease or otherwise acquire oil and natural gas properties, including both unproved and unevaluated leasehold and purchases of reserves in place. For the years ended December 31, 2015, 2014 and 2013, most of the Company’s property acquisition costs resulted from the acquisition of unproved and unevaluated leasehold positions.
Exploration costs are costs incurred in identifying areas of these oil and natural gas properties that may warrant further examination and in examining specific areas that are considered to have prospects of containing oil and natural gas, including costs of drilling exploratory wells, geological and geophysical costs, and costs of carrying and retaining unproved and unevaluated properties. Exploration costs may be incurred before or after acquiring the related oil and natural gas properties.
Development costs are costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing oil and natural gas. Development costs include the costs of preparing well locations for drilling, drilling and equipping development wells and related service wells (e.g., salt water disposal wells) and acquiring, constructing and installing production facilities.
Costs incurred also include new asset retirement obligations established, as well as changes to asset retirement obligations resulting from revisions in cost estimates or abandonment dates. Asset retirement obligations included in the table above were approximately $3.3 million, $4.0 million and $1.5 million for the years ended December 31, 2015, 2014 and 2013, respectively. Capitalized general and administrative expenses that are directly related to acquisition, exploration and development activities are also included in the table above. The Company capitalized $6.9 million, $6.4 million and $3.7 million of these internal costs in 2015, 2014 and 2013, respectively. Capitalized interest expense for qualifying projects is also included in the table above. The Company capitalized $3.9 million, $2.8 million and $1.9 million of its interest expense for the years ended December 31, 2015, 2014 and 2013, respectively.
Oil and Natural Gas Reserves
Proved reserves are estimated quantities of oil and natural gas which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs using existing economic and operating conditions. Estimating oil and natural gas reserves is complex and is inexact because of the numerous uncertainties inherent in the process. The process relies on interpretations of available geological, geophysical, petrophysical, engineering and production data. The extent, quality and reliability of both the data and the associated interpretations of that data can vary. The process also requires certain economic assumptions, including, but not limited to, oil and natural gas prices, drilling, completion and operating expenses, capital expenditures and taxes. Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses

and quantities of recoverable oil and natural gas most likely will vary from the Company’s estimates.
The Company reports its production and proved reserves in two streams: oil and natural gas, including both dry and liquids-rich natural gas. Where the Company produces liquids-rich natural gas, such as in the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas and the Eagle Ford shale in South Texas, the economic value

of the natural gas liquids associated with the natural gas is included in the estimated wellhead natural gas price on those properties where the natural gas liquids are extracted and sold. The Company's oil and natural gas reserves estimates for the years ended December 31, 2015, 2014 and 2013 were prepared by the Company's engineering staff in accordance with guidelines established by the SEC and then audited for their reasonableness and conformance with SEC guidelines by Netherland, Sewell & Associates, Inc., independent reservoir engineers.

Oil and natural gas reserves are estimated using then-current operating and economic conditions, with no provision for price and cost escalations in future periods except by contractual arrangements. The commodity prices used to estimate oil and natural gas reserves are based on unweighted, arithmetic averages of first-day-of-the-month oil and natural gas prices for the previous 12-month period. For the period from January through December 2015, these average oil and natural gas prices were $46.79 per barrel and $2.59 per MMBtu, respectively. For the period from January through December 2014, these average oil and natural gas prices were $91.48 per barrel and $4.35 per MMBtu, respectively. For the period from January through December 2013, these average oil and natural gas prices were $93.42 per barrel and $3.67 per MMBtu, respectively.

The Company's net ownership in estimated quantities of proved oil and natural gas reserves and changes in net proved reserves are summarized as follows. All of the Company's oil and natural gas reserves are attributable to properties located in the United States. The estimated reserves shown below are for proved reserves only and do not include any value for unproved reserves classified as probable or possible reserves that might exist for these properties, nor do they include any consideration that could be attributed to interests in unevaluated acreage beyond those tracts for which reserves have been estimated. In the tables presented throughout this section, natural gas is converted to oil equivalent using the ratio of one Bbl of oil to six Mcf of natural gas.

Table of Contents

Matador Resources Company and Subsidiaries

UNAUDITED SUPPLEMENTARY INFORMATION — CONTINUED

December 31, 2015, 2014 and 2013

SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES — Continued

	Net Proved Reserves		
	Oil	Natural Gas	Oil Equivalent
	(MBbl)	(MMcf)	(MBOE)
Total at December 31, 2012	10,485	80,007	23,819
Revisions of prior estimates	(199)	78,812	12,936
Purchases of minerals in-place	—	170	28
Extensions and discoveries	8,209	66,121	19,231
Production	(2,133)	(12,915)	(4,285)
Total at December 31, 2013	16,362	212,195	51,729
Revisions of prior estimates	(1,196)	164	(1,169)
Purchases of minerals in-place	10	433	82
Extensions and discoveries	12,328	69,566	23,921
Production	(3,320)	(15,303)	(5,870)
Total at December 31, 2014	24,184	267,055	68,693
Revisions of prior estimates	(2,609)	(75,433)	(15,181)
Purchases of minerals in-place	1,102	2,927	1,589
Extensions and discoveries	27,459	70,054	39,135
Production	(4,492)	(27,702)	(9,109)
Total at December 31, 2015	45,644	236,901	85,127
Proved Developed Reserves			
December 31, 2012	4,764	54,040	13,771
December 31, 2013	8,258	53,458	17,168
December 31, 2014	14,053	102,795	31,185
December 31, 2015	17,129	101,447	34,037
Proved Undeveloped Reserves			
December 31, 2012	5,721	25,967	10,048
December 31, 2013	8,104	158,737	34,561
December 31, 2014	10,131	164,260	37,508
December 31, 2015	28,515	135,454	51,090

The following is a discussion of the changes in the Company’s proved oil and natural gas reserves estimates for the years ended December 31, 2015, 2014 and 2013.

The Company’s proved oil and natural gas reserves increased to 85,127 MBOE at December 31, 2015 from 68,693 MBOE at December 31, 2014. The Company’s proved oil and natural gas reserves increased by 25,543 MBOE and the Company produced 9,109 MBOE during the year ended December 31, 2015, resulting in a net increase of 16,434 MBOE. An increase of 39,135 MBOE in proved oil and natural gas reserves was a result of extensions and discoveries during the year, which was primarily attributable to drilling operations in the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas. The Company’s proved oil and natural gas reserves decreased by 15,181 MBOE during the year as a result of revisions to previous estimates, primarily the removal of approximately 1,935 MBbl of proved undeveloped oil reserves in the Eagle Ford shale play in South Texas in 2015, as well as the removal of approximately 64.3 Bcf, or 10,716 MBOE, of proved undeveloped natural gas reserves, primarily in the Haynesville shale in Northwest Louisiana, resulting from the decline in commodity prices during 2015. The Company also purchased minerals in-place with proved reserves of 1,589 MBOE in 2015, primarily as part of the HEYCO Merger. The Company’s proved developed oil and natural gas reserves increased to 34,037 MBOE at December 31, 2015 from 31,185 MBOE at December 31, 2014, primarily due to proved developed reserves added as a result of drilling operations in the Wolfcamp and Bone Spring plays in the Delaware Basin and the Eagle Ford shale plus the conversion of previously undeveloped natural gas reserves in the Haynesville shale to proved developed reserves. At December 31, 2015, the Company’s proved reserves were made up of approximately 54% oil and 46% natural gas and were approximately 40% proved developed and approximately 60% proved undeveloped.

The Company's proved oil and natural gas reserves increased to 68,693 MBOE at December 31, 2014 from 51,729 MBOE at December 31, 2013. The Company's proved oil and natural gas reserves increased by 22,834 MBOE and the Company produced 5,870 MBOE during the year ended December 31, 2014, resulting in a net increase of 16,964 MBOE. An increase of 23,921 MBOE in proved oil and natural gas reserves was a result of extensions and discoveries during the year, which was primarily attributable to drilling operations in the Eagle Ford shale play in South Texas and in the Wolfcamp and Bone Spring plays in the Delaware Basin in Southeast New Mexico and West Texas, plus additional proved undeveloped natural gas reserves identified on the Company's properties in the Haynesville shale. The Company's proved oil and natural gas reserves decreased by 1,169 MBOE during the year as a result of revisions to previous estimates, primarily downward revisions of proved undeveloped oil reserves on certain of the Company's undeveloped locations in the Eagle Ford shale play in South Texas in 2014. The Company also purchased minerals in-place with proved reserves of 82 MBOE in 2014. The Company's proved developed oil and natural gas reserves increased to 31,185 MBOE at December 31, 2014 from 17,168 MBOE at December 31, 2013, primarily due to proved developed reserves added as a result of drilling operations in the Eagle Ford shale and in the Wolfcamp and Bone Spring plays in the Delaware Basin plus the conversion of previously undeveloped natural gas reserves in the Haynesville shale to proved developed reserves. At December 31, 2014, the Company's proved reserves were made up of approximately 35% oil and 65% natural gas and were approximately 45% proved developed and approximately 55% proved undeveloped.

The Company's proved oil and natural gas reserves increased to 51,729 MBOE at December 31, 2013 from 23,819 MBOE at December 31, 2012. The Company's proved oil and natural gas reserves increased by 32,195 MBOE and the Company produced 4,285 MBOE during the year ended December 31, 2013, resulting in a net increase of 27,910 MBOE. An increase of 19,231 MBOE in proved oil and natural gas reserves was a result of extensions and discoveries during the year, which was primarily attributable to drilling operations in the Eagle Ford shale play in South Texas and additional proved undeveloped natural gas reserves identified on the Company's properties in the Haynesville shale. The Company's proved oil and natural gas reserves increased by 12,936 MBOE during the year as a result of revisions to previous estimates, primarily upward revisions in the Company's proved undeveloped natural gas reserves resulting from higher natural gas prices in 2013. The Company also purchased minerals in-place with proved reserves of 28 MBOE in 2013. The Company's proved developed oil and natural gas reserves increased to 17,168 MBOE at December 31, 2013 from 13,771 MBOE at December 31, 2012, primarily due to proved developed reserves added as a result of drilling operations in the Eagle Ford shale. At December 31, 2013, the Company's proved reserves were made up of approximately 32% oil and 68% natural gas and were approximately 33% proved developed and 67% proved undeveloped.

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein Relating to Proved Oil and Natural Gas Reserves

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves is not intended to provide an estimate of the replacement cost or fair market value of the Company's oil and natural gas properties. An estimate of fair market value would also take into account, among other things, the recovery of reserves not presently classified as proved, anticipated future changes in prices and costs, potential improvements in industry technology and operating practices, the risks inherent in reserves estimates and perhaps different discount rates.

As noted previously, for the period from January through December 2015, the unweighted, arithmetic averages of first-day-of-the-month oil and natural gas prices were $46.79 per barrel and $2.59 per MMBtu, respectively. For the period from January through December 2014, the comparable average oil and natural gas prices were $91.48 per barrel and $4.35 per MMBtu, respectively. For the period from January through December 2013, the comparable average oil and natural gas prices were $93.42 per barrel and $3.67 per MMBtu, respectively.

Future net cash flows were computed by applying these oil and natural gas prices, adjusted for all associated transportation and marketing costs, gravity and energy content, and regional price differentials, to year-end quantities of proved oil and natural gas reserves and accounting for any future production and development costs associated with producing these reserves; neither prices nor costs were escalated with time in these computations.

Future income taxes were computed by applying the statutory tax rate to the excess of future net cash flows relating to proved oil and natural gas reserves less the tax basis of the associated properties. Tax credits and net operating loss carryforwards available to the Company were also considered in the computation of future income taxes. Future net cash flows after income taxes were discounted using a 10% annual discount rate to derive the standardized measure of discounted future net cash flows.

Matador Resources Company and Subsidiaries
UNAUDITED SUPPLEMENTARY INFORMATION — CONTINUED
December 31, 2015, 2014 and 2013
SUPPLEMENTAL OIL AND NATURAL GAS DISCLOSURES — Continued

The following table presents the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves for the years ended December 31, 2015, 2014 and 2013 (in thousands).

	Year Ended December 31,		
	2015	2014	2013
Future cash inflows	$2,461,131	$3,197,317	$2,316,626
Future production costs	(843,117)	(803,662)	(666,450)
Future development costs	(615,692)	(553,799)	(507,923)
Future income tax expense	(43,956)	(321,088)	(181,041)
Future net cash flows	958,366	1,518,768	961,212
10% annual discount for estimated timing of cash flows	(429,185)	(605,449)	(382,544)
Standardized measure of discounted future net cash flows	$529,181	$913,319	$578,668

The following table summarizes the changes in the standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves for the years ended December 31, 2015, 2014 and 2013 (in thousands).

	Year Ended December 31,		
	2015	2014	2013
Balance, beginning of period	$913,319	$578,668	$394,636
Net change in sales and transfer prices and in production (lifting) costs related to future production	(509,901)	87,067	(97,511)
Changes in estimated future development costs	(145,861)	(150,447)	(233,232)
Sales and transfers of oil and natural gas produced during the period	(184,612)	(283,187)	(209,338)
Purchases of reserves in place	16,321	1,838	176
Net change due to extensions and discoveries	401,895	537,472	386,696
Net change due to revisions in estimates of reserves quantities	(285,823)	(26,263)	260,148
Previously estimated development costs incurred during the period	121,543	187,459	106,348
Accretion of discount	82,574	65,518	36,184
Other	2,029	5,492	(371)
Net change in income taxes	117,697	(90,298)	(65,068)
Standardized measure of discounted future net cash flows	$529,181	$913,319	$578,668

Table of Contents

Matador Resources Company and Subsidiaries
UNAUDITED SUPPLEMENTARY INFORMATION — CONTINUED
December 31, 2015, 2014 and 2013

SELECTED QUARTERLY FINANCIAL INFORMATION

The following table presents selected unaudited quarterly financial information for 2015 (in thousands, except per share data).

	December 31	September 30	June 30	March 31
2015				
Oil and natural gas revenues	$56,212	$71,815	$87,848	$62,465
Realized gain on derivatives	24,948	19,862	13,780	18,504
Unrealized (loss) gain on derivatives	(13,909)	6,733	(23,532)	(8,557)
Expenses[1]	290,769	367,499	319,095	147,217
Other expense	5,101	6,230	5,367	1,783
(Loss) income before income taxes	(228,619)	(275,319)	(246,366)	(76,588)
Income tax provision (benefit)	1,677	(33,305)	(89,350)	(26,390)
Net loss	(230,296)	(242,014)	(157,016)	(50,198)
Net income attributable to non-controlling interest in subsidiaries	(105)	(45)	(75)	(36)
Net loss attributable to Matador Resources Company shareholders	$(230,401)	$(242,059)	$(157,091)	$(50,234)
Loss per common share attributable to Matador Resources Company shareholders				
Basic	$(2.72)	$(2.86)	$(1.89)	$(0.68)
Diluted	$(2.72)	$(2.86)	$(1.89)	$(0.68)

(1) Expenses for December 31, September 30, June 30 and March 31, 2015 included full-cost ceiling impairment charges of $219.4 million, $285.7 million, $229.0 million and $67.1 million, respectively.

The following table presents selected unaudited quarterly financial information for 2014 (in thousands, except per share data).

	December 31	September 30	June 30	March 31
2014				
Oil and natural gas revenues	$93,110	$96,617	$99,054	$78,931
Realized gain (loss) on derivatives	10,479	(701)	(2,913)	(1,843)
Unrealized gain (loss) on derivatives	50,351	16,293	(5,234)	(3,108)
Expenses	78,675	65,680	60,840	46,723
Other expense	1,018	406	1,207	1,358
Income before income taxes	74,247	46,123	28,860	25,899
Income tax provision	27,701	16,504	10,634	9,536
Net income	46,546	29,619	18,226	16,363
Net loss attributable to non-controlling interest in subsidiaries	17	—	—	—
Net income attributable to Matador Resources Company shareholders	$46,563	$29,619	$18,226	$16,363
Earnings per common share attributable to Matador Resources Company shareholders				
Basic	$0.63	$0.40	$0.27	$0.25

Diluted	$0.63	$0.40	$0.26	$0.25

F-40