Matador Resources Co
Form 10-K
March 17, 2014

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, 2013

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 ¨ No ý

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. ¨

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¨			Accelerated filer	ý
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 $593,728,477.

As of March 13, 2014, there were 65,744,878 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 2014 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.

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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," "intend," "may," "might," "potential," "predict," "project," "should" or other similar words.

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: changes in oil or natural gas prices, 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, 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 U.S. Securities and Exchange Commission (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;
- government regulation and taxation of the oil and natural gas industry;
- our marketing of oil and natural gas;
- our exploitation projects or property acquisitions;
- 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 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

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forward-looking statements, except as required by law, including the securities laws of the United States and the rules and regulations of the SEC.

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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 before the completion of our corporate reorganization on August 9, 2011 and Matador Holdco, Inc. and its subsidiaries after the completion of our corporate reorganization on August 9, 2011. Prior to August 9, 2011, Matador Holdco, Inc. was a wholly-owned subsidiary of Matador Resources Company, now known as MRC Energy Company. Pursuant to the terms of our corporate reorganization, former Matador Resources Company became a wholly-owned subsidiary of Matador Holdco, Inc. and changed its corporate name to MRC Energy Company, and Matador Holdco, Inc. changed its corporate name to Matador Resources Company.

Unless the context otherwise requires, the term "common stock" refers to shares of our common stock after the conversion of our Class B common stock into Class A common stock upon the consummation of our initial public offering on February 7, 2012, as the Class A common stock then became the only class of common stock authorized, and 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.

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 Eagle Ford shale play in South Texas and the Wolfcamp and Bone Spring plays in the Permian Basin in Southeast New Mexico and West Texas. We also operate in the Haynesville shale and Cotton Valley plays in Northwest Louisiana and East Texas. In addition, we have a large exploratory leasehold position in Southwest Wyoming and adjacent areas of Utah and Idaho where we are testing the Meade Peak shale.

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 exploration and development activity on our Eagle Ford acreage in South Texas;
- explore and develop our Wolfcamp and Bone Spring acreage in the Permian Basin;
- identify, evaluate and develop oil and natural gas plays to maintain a balanced portfolio;
- continue to improve operational and cost efficiencies;
- maintain our financial discipline; and
- pursue opportunistic acquisitions.

The successful execution of our business strategies in 2013 led to significant increases in our oil and natural gas revenues and Adjusted EBITDA, oil production and proved oil and natural gas reserves, and the associated increase in the PV-10 of our proved reserves. We also significantly increased our leasehold position in the Permian Basin and added to our acreage positions in the Eagle Ford shale and the Haynesville shale. Adjusted EBITDA and PV-10 are non-GAAP financial measures. For a definition of such terms and a reconciliation to the most directly comparable GAAP financial measures, see “Selected Financial Data — Non-GAAP Financial Measures” and “—Estimated Proved Reserves.”

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2013 Highlights

Increased Oil and Natural Gas Revenues and Adjusted EBITDA

Our oil and natural gas revenues for the year ended December 31, 2013 were the highest achieved in any fiscal year in the Company's history. Our oil and natural gas revenues increased $113.0 million to $269.0 million in 2013, which represents an increase of 72% from 2012. This revenue increase was primarily driven by a significant increase in our oil production in 2013 and a higher weighted average natural gas price realized in 2013. Our Adjusted EBITDA of $191.8 million for 2013 was an increase of 65%, as compared to our Adjusted EBITDA of $115.9 million for 2012. 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."

Increased Oil and Oil Equivalent Production

Our total oil production and our average daily oil equivalent production for the year ended December 31, 2013 were the best in our history. In 2013, we produced 2.1 million barrels of oil, an increase of 76%, as compared to 1.2 million barrels of oil produced in 2012. Our average daily oil equivalent production was 11,740 BOE per day, including 5,843 Bbl of oil per day and 35.4 MMcf of natural gas per day, an increase of 30%, as compared to 9,000 BOE per day, including 3,317 Bbl of oil per day and 34.1 MMcf of natural gas per day, for the year ended December 31, 2012. This increase in oil production was a direct result of our drilling operations in the Eagle Ford shale. We achieved this increased oil production despite having as much as 15% to 20% of our production capacity shut in at various times during 2013, as we continued our operational practices of pad and batch drilling in the Eagle Ford shale and shutting in producing wells while conducting drilling and completion operations on offsetting wells. Oil production comprised 50% 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, 2013, as compared to 37% for the year ended December 31, 2012 and 6% for the year ended December 31, 2011.

Increased Oil and Natural Gas Reserves

At December 31, 2013, our estimated total proved oil and natural gas reserves were 51.7 million BOE, including 16.4 million Bbl of oil and 212.2 Bcf of natural gas, which is an increase of 117% from December 31, 2012. The associated PV-10 of our estimated total proved oil and natural gas reserves increased 55% to $655.2 million at December 31, 2013 from $423.2 million at December 31, 2012. 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 56% to 16.4 million Bbl at December 31, 2013, as compared to 10.5 million Bbl at December 31, 2012. This growth in oil reserves was primarily attributable to our drilling program in the Eagle Ford shale during 2013. Our proved natural gas reserves increased 165% to 212.2 Bcf at December 31, 2013 from 80.0 Bcf at December 31, 2012. This large increase in proved natural gas reserves was attributable to our drilling and completion activities and improvements in natural gas prices in 2013. As a result of the continued improvement in natural gas prices during 2013, we re-classified Haynesville shale natural gas volumes previously removed from our proved reserves in 2012 as proved undeveloped reserves in 2013 and also included additional Haynesville shale proved undeveloped natural gas reserves in our total proved reserves at December 31, 2013.

At December 31, 2013, proved developed reserves included 8.3 million Bbl of oil and 53.5 Bcf of natural gas, and proved undeveloped reserves included 8.1 million Bbl of oil and 158.7 Bcf of natural gas. Proved developed reserves comprised 33% and proved oil reserves comprised 32% of our total proved oil and natural gas reserves, respectively, at December 31, 2013. Based on our 2013 year-end total proved reserves and our 2013 oil equivalent production of 4.3 million BOE, we improved our reserves/production ("R/P") ratio to 12.1 years at December 31, 2013, as compared to 7.2 years at December 31, 2012.

Operational Efficiencies

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 manage more effectively 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 Eagle Ford shale wells, particularly over the past two years.

During this time, we have progressed from drilling wells on single-well pads to multi-well pad drilling, and most recently, to multi-well batch drilling. In August 2013, we began drilling certain wells on our western Eagle Ford acreage from batch drilled pads using a drilling rig equipped with a “walking” package and, as a result, we have improved both drilling times and costs. We have realized cost savings of approximately $325,000 per well on initial wells drilled using this rig, and we expect the use of batch drilling and the “walking” rig will lead to total cost savings of approximately $400,000 per well or more going forward. Recent wells drilled on our western Eagle Ford acreage in La Salle County, Texas have drilling times from spud to total depth of eight to 10 days per well and costs at or just below $6 million per well. In April 2014, we expect to replace the drilling rig currently operating in the central portion of our acreage in Karnes and Wilson Counties, Texas with a new “walking” rig. At that time, we will have two “walking” rigs operating in the Eagle Ford and will conduct batch drilling operations on our properties using these rigs for the balance of 2014. Recent wells in our central Eagle Ford acreage have been drilled for between $7.0 and $7.5 million, but we expect to see further cost improvements with the initiation of batch drilling operations in this area as well. We anticipate that we will drill almost 250,000 lateral feet with two rigs in the Eagle Ford in 2014, as compared to 150,000 feet using two rigs in 2012 and effectively 1.5 rigs in 2013, an increased drilling efficiency of almost 70%.

During 2013, we continued to refine the design of our hydraulic fracture treatments to enhance well productivity and ultimate hydrocarbon recovery, increasing fluid volumes to 40 Bbl per foot and proppant volumes to more than 2,000 pounds per foot, while decreasing the spacing between perforation clusters where the fractures are initiated. These Generation 5, and now Generation 6, fracture treatments are resulting in significant improvements in initial well productivity as compared to earlier generation treatment designs. We also believe that initiating the use of gas lift relatively early in the life of our newly drilled Eagle Ford wells has accelerated oil production, reduced lease operating expenses, lowered maintenance costs and helped our wells recover faster after being shut in for offset well operations.

Acreage Acquisitions

During 2013, we acquired approximately 55,400 gross (38,900 net) acres in the Permian Basin in Southeast New Mexico and West Texas. These acreage acquisitions brought our total Permian Basin acreage position to approximately 70,800 gross (44,800 net) acres as of December 31, 2013. Between January 1 and December 31, 2013, we also acquired approximately 1,720 gross (1,660 net) acres in the Eagle Ford shale play in South Texas and approximately 1,190 gross (1,190 net) acres in the Haynesville shale play in Northwest Louisiana.

Issuance of Common Stock

In April 2013, we filed with the SEC a universal shelf registration statement on Form S-3 (the “Shelf Registration Statement”), which provided us with the ability to offer and sell up to $300 million of debt and equity securities, subject to market conditions and our capital needs. The SEC declared the Shelf Registration Statement effective on May 9, 2013. As of December 31, 2013, we had approximately $151 million of securities available for issuance under the Shelf Registration Statement.

On September 10, 2013, we completed an underwritten public offering of 9,775,000 shares of our common stock and received net proceeds of approximately $141.7 million. The net proceeds from this offering were used to fund a portion of our capital expenditures, including the addition of a third rig to our drilling program and the acquisition of additional acreage in the Eagle Ford shale, the Permian Basin and the Haynesville shale. Pending such uses, we used a portion of the net proceeds to repay $130.0 million in outstanding borrowings under our third amended and restated credit agreement (the “Credit Agreement”) in September 2013, which amounts may be reborrowed in accordance with the terms of that facility for, among other items, the uses contemplated above.

Recent Developments

On March 12, 2014, the borrowing base under our Credit Agreement was increased to $385.0 million, and the conforming borrowing base was increased to $310.0 million based on the lenders’ review of our proved oil and natural gas reserves at December 31, 2013. At that time, we also amended our Credit Agreement to include Wells Fargo Bank, N.A., which replaced Capital One, N.A., in our lending group, which also includes Royal Bank of Canada, as administrative agent, Comerica Bank, Citibank, N.A., The Bank of Nova Scotia, SunTrust Bank, BMO Harris Financing, Inc. (Bank of Montreal) and IberiaBank. At March 13, 2014, we had $250.0 million in borrowings and $0.3 million in letters of credit outstanding under our Credit Agreement.

Between January 1 and March 13, 2014, we acquired an additional 7,000 gross (5,300 net) acres in Southeast New Mexico and West Texas, bringing our total Permian Basin acreage position to 77,800 gross (50,100 net) acres as of March 13, 2014.

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 Eagle Ford shale play in South Texas, the Haynesville shale play in Northwest Louisiana and most recently, the Wolfcamp and Bone Spring plays in the Permian Basin in Southeast New Mexico and West Texas. During 2013, we devoted most of our efforts and most of our capital investment to our drilling operations in the Eagle Ford shale in South Texas as we sought to continue to increase our oil production and reserves. Since our inception, our exploration efforts have

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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, 2013, essentially all of our efforts are focused on unconventional plays.

At December 31, 2013, our principal areas of interest consisted of the Eagle Ford shale play in South Texas, the Wolfcamp and Bone Spring plays in the Permian Basin in Southeast New Mexico and West Texas, the Haynesville shale play, as well as the traditional Cotton Valley and Hosston (Travis Peak) formations, in Northwest Louisiana and East Texas, and the Meade Peak shale play in Southwest Wyoming and the adjacent areas of Utah and Idaho.

The following table presents certain summary data for each of our operating areas as of and for the year ended December 31, 2013:

	Net Acreage	Producing Wells		Total Identified Drilling Locations (1)		Estimated Net Proved Reserves (2)		Avg. Daily Production (BOE/d) (3)
		Gross	Net	Gross	Net	MBOE (3)	% Developed	
South Texas:								
Eagle Ford (4)	27,147	73	63.3	273	229.3	20,221	54.9	8,225
NW Louisiana/E Texas:								
Haynesville	14,969	140	13.0	527	114.5	28,797	14.9	2,831
Cotton Valley (5)	21,821	100	63.7	71	49.3	1,339	100.0	600
Area Total (6)	25,761	240	76.7	598	163.8	30,136	18.7	3,431
Permian Basin:								
SE New Mexico, West Texas (7)	44,834	13	5.0	241	177.7	1,372	31.1	84
Other:								
Wyoming, Utah, Idaho	36,004	—	—	—	—	—	—	—
Total	133,746	326	145.0	1,112	570.8	51,729	33.2	11,740

(1) Identified and engineered drilling locations. These locations have been identified for potential future drilling and were not producing at December 31, 2013. The total net engineered drilling locations is calculated by multiplying the gross engineered drilling locations in an operating area by our working interest participation in such locations. At December 31, 2013, these engineered drilling locations included 52 gross (39.8 net) locations to which we have assigned proved undeveloped reserves in the Eagle Ford, four gross (3.4 net) locations to which we have assigned proved undeveloped reserves in the Wolfcamp or Bone Spring plays in the Permian Basin and 125 gross (20.6 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 formation at December 31, 2013.

(2) These estimates were prepared by our engineering staff and audited by Netherland, Sewell & Associates, Inc., independent reservoir engineers.

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

(4) Includes two wells 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.

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

(6) 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.

(7) Includes potential future engineered drilling locations in the Wolfcamp, Bone Spring or Avalon shale plays on our acreage in the Permian Basin at December 31, 2013.

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 and others. At December 31, 2013, we were the operator for approximately 90% of our Eagle Ford acreage and 70% 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 a subsidiary of Chesapeake Energy Corporation. We also operate the majority of our acreage in the Permian Basin in Southeast New Mexico and West Texas, as well as all of our acreage in Southwest Wyoming and the adjacent areas of Utah and Idaho. In those wells where we are not the operator, our working interests are often relatively small, particularly in the Haynesville shale.

From time to time, we enter into joint operating agreements with our co-working interest partners governing operations on certain of our jointly owned wells and properties. Particularly when our working interest is small, however, we do not always enter into formal operating agreements with the operators, and in such cases, we rely on applicable legal and statutory authority to govern our business arrangement in accordance with industry standard practices. Where we do have joint operating agreements with affiliates of other companies, these agreements call for significant penalties should we elect not to participate in the drilling and completion of a well proposed by the operator, or a non-consent well. These non-consent penalties typically allow the operator to recover up to 400% of its costs to drill, complete and equip the non-consent well from the well’s future net revenue prior to us being allowed to participate in the non-consent well for our original working interest. Ultimately, the amount of these penalties may result in us having no participation at all in the non-consent well. We also have the right to propose wells under these joint operating agreements, and the same non-consent penalties apply to the operator should it elect not to consent to a well that we propose.

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.

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, 2013, our properties included approximately 39,000 gross (27,100 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 87% 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, 2013, and approximately 97% of our Eagle Ford acreage was either held by production at December 31, 2013 or not burdened by lease expirations before 2015. During the year ended December 31, 2013, we acquired approximately 1,720 gross (1,660 net) acres in the Eagle Ford shale play that we consider to be prospective primarily for oil production. This acreage essentially replaced the acreage upon which we drilled and established oil and natural gas production and reserves during 2013.

At December 31, 2013, we had 73 gross (63.3 net) wells producing from the Eagle Ford shale in South Texas. We had drilled and completed a total of 61 gross (59.5 net) Eagle Ford wells on our operated properties, and we had also participated in 12 gross (3.8 net) Eagle Ford wells with co-working interest owners on certain of our non-operated Eagle Ford properties.

During 2013, approximately 70% of our total capital expenditures of $373.5 million were directed to our operations in South Texas, and almost entirely in the Eagle Ford shale, as we continued executing our strategy to significantly increase our oil production and oil reserves. During the first quarter of 2013, we had two contracted drilling rigs operating full-time in South Texas and all of our operated drilling and completion activities were focused on the Eagle Ford shale. In late April 2013, we moved one of these contracted drilling rigs to Southeast New Mexico, while the second contracted drilling rig continued to operate in the Eagle Ford shale. In mid-August 2013, we added a third contracted drilling rig to our drilling program and returned to operating two contracted drilling rigs in the Eagle Ford shale play. We expect to operate two contracted drilling rigs in South Texas throughout 2014. At March 13, 2014, one of our two Eagle Ford rigs was operating in southern Wilson County, Texas, while the other was operating in La Salle County, Texas. The development of our Eagle Ford shale properties in South Texas will continue to be the primary driver of our growth in 2014, and we intend to direct approximately $318.4 million, or 72%, of our estimated 2014 capital expenditure budget of $440.0 million to our operations in South Texas.

During the year ended December 31, 2013, we completed and began producing oil and natural gas from 32 gross (27.6 net) Eagle Ford shale wells drilled on our acreage position in South Texas, including 25 gross (25.0 net) operated and seven gross (2.6 net) non-operated wells. As we completed and began producing oil and natural gas from these wells during 2013, our Eagle Ford production increased significantly. For the year ended December 31, 2013, 70% of our daily oil equivalent production, or 8,225 BOE per day, including 5,748 Bbl of oil per day and 14.9 MMcf of natural gas per day, was produced from the Eagle Ford shale. Almost all of our oil production in 2013 and 2012 was attributable to the Eagle Ford shale. The Eagle Ford shale contributed approximately 98% of our daily oil production and approximately 42% of our daily natural gas production during 2013, as compared to approximately 98% of our daily oil production and approximately 12% of our daily natural gas production during 2012. During the year ended December 31, 2012, approximately 44% of our daily production, or 3,928 BOE per day, including 3,261 Bbl of oil per day and 4.0 MMcf of natural gas per day, was attributable to the Eagle Ford shale. During the year ended December 31, 2011, only about 8% of our daily production, or 548 BOE per day, including 331 Bbl of oil per day and 1.3 MMcf of natural gas per day, was attributable to the Eagle Ford shale. This growth in oil and natural gas production from the Eagle Ford shale over the past several years reflects our ongoing drilling and completion operations in South Texas. Natural gas produced from most of our Eagle Ford shale wells is a liquids-rich natural gas and our purchasers process this natural gas for us at their processing facilities to remove the natural gas liquids, such as ethane, propane and other heavier natural gas liquids components. Our Eagle Ford wells typically yield five to seven gallons of natural gas liquids per Mcf of natural gas produced at the wellhead depending on the specific property.

At December 31, 2013, approximately 39% of our estimated total proved oil and natural gas reserves, or 20.2 million BOE, was attributable to the Eagle Ford shale, including approximately 15.2 million Bbl of oil and 30.1 Bcf of natural gas. Our proved reserves attributable to the Eagle Ford shale increased approximately 41% to 20.2 million BOE for the year ended December 31, 2013, as compared to 14.4 million BOE for the year ended December 31, 2012. Our Eagle Ford proved reserves at December 31, 2013 comprised approximately 93% of our proved oil reserves and 14% of our proved natural gas reserves, as compared to approximately 99% of our proved oil reserves and 30% of our proved natural gas reserves at December 31, 2012. The PV-10 of our proved reserves in the Eagle Ford shale at December 31, 2013 was $540.4 million, or approximately 82% of the PV-10 of our total proved reserves of $655.2 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, 2013, we have identified and engineered 273 gross (229.3 net) 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 criteria. Of the 273 gross (229.3 net) engineered locations identified for potential future drilling in the Eagle Ford shale at December 31, 2013, we consider 150 gross (125.9 net) locations to be Tier 1 locations. We define Tier 1 Eagle Ford locations as those locations that we anticipate to have estimated ultimate recoveries of 225,000 Bbl of oil or greater. Of these Tier 1 locations, 114 gross (111.5 net) locations would be operated by us. These identified locations presume that we will be able to develop our Eagle Ford properties on 40-acre to 80-acre spacing, depending on the specific property and the wells we have already drilled. As a result of the initial performance of test wells drilled on 40-acre and 50-acre spacing during 2013, we anticipate that Eagle Ford shale wells on our acreage in central and northern La Salle County, northern Karnes County and southern Wilson County can be developed on 40-acre spacing, while our other properties may be more likely developed on 80-acre spacing. We are currently drilling on 40-acre spacing on most of our properties in central and northern La Salle County, northern Karnes County and southern Wilson County. On our properties in the eastern portion of our Eagle Ford acreage in DeWitt County, we continue to drill on 80-acre spacing with no plans to test less than 80-acre spacing at December 31, 2013, because we believe that higher permeability, better transmissibility and higher pressure in these areas make these properties less conducive to reduced spacing.

We define Tier 2 Eagle Ford locations, including 123 gross (103.4 net) locations, as those locations that we anticipate to have estimated ultimate recoveries of between 150,000 Bbl and 225,000 Bbl of oil, locations that are primarily prospective for natural gas or locations with lesser estimates of ultimate oil recovery, but on properties already held by existing production. At December 31, 2013, Tier 2 locations were identified primarily on our acreage in Zavala County, southern La Salle County and eastern Gonzales County. We have identified no potential future Eagle Ford drilling locations on our Atascosa County acreage. All of these Tier 2 locations would be operated by us, and almost all of these locations are on properties already held by production from the Eagle Ford or other producing horizons. Although we have no plans to drill any of these Tier 2 locations in 2014, as long as these properties remain held by production, or remain in the primary terms of the leases, these locations remain available for us to drill at a later time should commodity prices improve, drilling and completion costs decline further or new technologies be developed that increase expected recoveries. Certain of these properties, such as our properties in Zavala and Atascosa Counties, also offer the opportunity to explore horizons other than the Eagle Ford, including the Austin Chalk, Buda, Edwards or Pearsall, and we may develop new prospects on these properties in the future. We have included one test of the Buda formation on our Zavala County acreage as part of our 2014 capital expenditure budget. As we explore and develop all of our Eagle Ford acreage further, we believe it is possible that we may identify additional locations for future drilling. At December 31, 2013, these 273 gross (229.3 net) potential future drilling locations included 52 gross (39.8 net) locations to which we have assigned proved undeveloped reserves.

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We believe that we have increased our technical knowledge of drilling, completing and producing Eagle Ford shale wells, particularly over the past two years. During this time, we have progressed from drilling wells on single-well pads to multi-well pad drilling, and most recently, to multi-well batch drilling. In August 2013, we began drilling certain wells on our western Eagle Ford acreage from batch drilled pads using a drilling rig equipped with a "walking" package and, as a result, we have improved both drilling times and costs. We realized cost savings of approximately $325,000 per well on initial wells drilled using this rig, and we expect the use of batch drilling and the "walking" rig will lead to total cost savings of approximately $400,000 per well or more going forward. Recent wells drilled on our western Eagle Ford acreage in La Salle County have drilling times from spud to total depth of eight to 10 days per well and costs at or just below $6 million per well. In April 2014, we expect to replace the drilling rig currently operating in the central portion of our acreage in Karnes and Wilson Counties with a new "walking" rig. At that time, we will have two "walking" rigs operating in the Eagle Ford and will conduct batch drilling operations on our properties using these rigs for the balance of 2014. Recent wells in our central Eagle Ford acreage have been drilled for between $7.0 and $7.5 million, but we expect to see further cost improvements with the initiation of batch drilling operations in this area as well. We anticipate that we will drill almost 250,000 lateral feet with two rigs in the Eagle Ford in 2014, as compared to 150,000 feet using two rigs in 2012 and effectively 1.5 rigs in 2013, an increased drilling efficiency of almost 70%.

During 2013, we continued to refine the design of our hydraulic fracture treatments to enhance well productivity and ultimate hydrocarbon recovery, increasing fluid volumes to 40 Bbl per foot and proppant volumes to more than 2,000 pounds per foot, while decreasing the spacing between perforation clusters where the fractures are initiated. These Generation 5, and now Generation 6, fracture treatments are resulting in significant improvements in initial well productivity as compared to earlier generation treatment designs. We also believe that initiating the use of gas lift relatively early in the life of our newly drilled Eagle Ford wells has accelerated oil production, reduced lease operating expenses, lowered maintenance costs and helped our wells recover faster after being shut in for offset well operations.

As we continue to explore and develop our leasehold positions in the Eagle Ford shale, we may face challenges with establishing operations in new areas and securing the necessary services to drill and complete wells and with securing the necessary pipeline and natural gas processing capabilities to process, transport and market the oil and natural gas we produce. We may also incur higher than anticipated costs associated with establishing new operating infrastructure on our leases throughout the area. We believe that we have successfully secured the necessary drilling and completion services for our current Eagle Ford operations. We did not experience difficulties in securing completion, and in particular hydraulic fracturing, services for our newly drilled wells during 2013 or 2012, although we experienced these problems at various times during 2011 in South Texas and may have such difficulties again in the future. We believe that maintaining reliable and timely drilling and completion services and optimizing drilling and completion costs will be essential to the successful development and profitability of the Eagle Ford 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."

In the past, we have experienced pipeline and natural gas processing interruptions and capacity and infrastructure constraints associated with natural gas production, which have, among other things, required us to flare natural gas occasionally. To alleviate a portion of the interruptions and processing capacity constraints we experienced during 2012, 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. No assurance can be made that this agreement will alleviate these issues completely, and if we were required to shut in or flare our production for long periods of time due to pipeline interruptions or lack of processing facilities or capacity of these facilities, it would have a material adverse effect on our business, financial condition, results of operations and cash flows. 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."

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, the Austin Chalk formation, which is a naturally fractured carbonate typically ranging in thickness from 200 to 400 feet, and the Buda formation, which is a naturally fractured carbonate typically ranging in thickness from 90 to 160 feet, have produced from several fields on or nearby portions of our acreage. We believe that approximately 21,000 gross (16,800 net) acres of our properties in South Texas are prospective for the Austin Chalk and 17,200 gross (13,300 net) acres are prospective for the Buda formation, which have historically been targeted by operators in South Texas.

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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 are prospective for the Buda formation. We believe our acreage is located within the extension of a trend where encouraging drilling by other operators has occurred in the Buda just southwest of our leasehold position. We have acquired a 3-D seismic survey over our acreage, and at March 13, 2014, we were evaluating a series of seismic attributes which are similar to fracture patterns observed in cores from other wells in the area and from our drilling of previous wells on the acreage in 2012 and which are consistent with regional mapping. At December 31, 2013, we had not included any Buda locations in our future drilling locations, although we do plan to drill one gross (1.0 net) exploratory well to test the Buda formation on our Glasscock Ranch property in 2014. We participated in one non-operated test of the Buda formation in South Texas (approximately 21% working interest) on one of our leases in Atascosa County during the first quarter of 2013. This well tested a strong initial oil flow from a very short horizontal lateral, but the well was plugged and abandoned after oil production from this interval declined to uneconomic levels soon thereafter. We do not expect to participate in any additional Buda tests on our Atascosa County acreage during 2014.

Southeast New Mexico and West Texas — Permian Basin

The 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 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 intense hydraulic fracturing techniques.

One example of such an opportunity appears to be the so-called “Wolf-Bone” play in the western Permian Basin. Together, the Lower Permian age Bone Spring (also called Leonardian) and Wolfcamp shale formations span several thousand feet of stacked shales, sandstones, limestones and dolomites, representing complex and dynamic submarine depositional systems that include several organic rich source rocks. Throughout these intervals, oil and natural gas have been produced primarily from conventional sandstone and carbonate reservoirs even though hydrocarbons are trapped in the tight sands, limestones and dolomites interbedded within organic rich shale. Recently, these hydrocarbon-bearing zones have been recognized and tested by a number of operators as targets for horizontal drilling and multi-stage hydraulic fracturing techniques. As a result, many industry players are expanding positions and conducting drilling programs throughout the western Permian Basin in Lea and Eddy Counties in Southeast New Mexico and Loving, Pecos, Reeves, Ward and Winkler Counties in West Texas. In addition, other industry players have been successful in developing similar formations on the eastern side of the Permian Basin, east of the Central Basin Platform in West Texas. Multiple horizontal drilling and completion targets are being identified and tested by companies throughout the vertical section including the Delaware, Avalon, Bone Spring (First, Second and Third sands) and multiple intervals within the Wolfcamp shale, often identified as the Wolfcamp “A” through “D” intervals.

During 2013, we added significantly to our acreage position and initiated an exploration program to begin testing our Permian Basin leasehold. We acquired an additional 55,400 gross (38,900 net) acres in Southeast New Mexico and West Texas. At December 31, 2013, our leasehold position included approximately 70,800 gross (44,800 net) acres in the Permian Basin, primarily in Lea and Eddy Counties, New Mexico and Loving County, Texas in the western Permian Basin. At December 31, 2013, approximately 7,000 gross (4,900 net) of these acres were held by production. We consider the vast majority of this acreage 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 shale and Delaware formations, as well as the Abo, Strawn, Devonian, Cisco/Canyon and Glorieta/San Andres formations. We have also acquired approximately 2,000 gross (1,450 net) acres in Howard and Dawson Counties, Texas in the eastern Permian Basin, although we do not expect to drill any wells in the eastern Permian Basin in 2014. In addition, a portion of our leasehold interests in the Permian Basin, including approximately 7,300 gross (450 net) acres in

Winkler County, Texas, is no longer considered to be prospective by us, and we plan to allow this acreage to expire without drilling.

At December 31, 2013 and March 13, 2014, we were running one contracted drilling rig in the Permian Basin to further evaluate and delineate our acreage position both geographically and geologically. During 2013, we drilled three wells in the Permian Basin - two in Lea County, New Mexico and one in Loving County, Texas. Our first well, the Ranger 12 State #1 well in Lea County, was a vertical data collection well where we took extensive well log and whole and sidewall core data in an effort to better understand the multiple potential completion targets throughout the vertical section. We were continuing to test multiple potential completion intervals in this well at December 31, 2013. Our second well, the Ranger 33 State Com #1H in Lea County, was a 4,300-ft horizontal lateral drilled and completed in the Second Bone Spring sand with 18 fracturing stages, including 165,000 Bbl of fluid and 7.5 million pounds of sand. This well was placed on production at the end of October 2013

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and has continued to exhibit strong performance. In its first three months on production, including the initial cleanup phase, the well produced over 48,000 BOE, including approximately 44,000 Bbl of oil (92% oil), and continued to flow with gas lift assist. Our third well, the Dorothy White #1H in Loving County, Texas, was a 5,000-ft horizontal lateral drilled in the upper portion of the Wolfcamp formation, the Wolfcamp "A", at approximately 10,700-ft vertical depth. We completed this well in January 2014 with 20 fracturing stages, including 200,000 Bbl of fluid and 9.8 million pounds of sand. The Dorothy White #1H was placed on production in January 2014 and flowed 1,355 BOE per day, including 902 Bbl of oil per day and 2.7 MMcf of natural gas per day (67% oil) at 3,711 pounds per square inch pressure ("psi") on a 22/64th inch choke during a 24-hour initial potential test.

Because of these encouraging initial results, we plan to run one rig continuously in the western Permian Basin throughout 2014. We have allocated approximately $108.6 million, or about 25% of our 2014 capital expenditure budget of $440.0 million, to our drilling and completion activities in the Permian Basin, as well as for the acquisition of additional leasehold interests in the area. The objective of our 2014 Permian Basin drilling program is to further evaluate and delineate our acreage position in an effort to define an expanded, multi-rig drilling program for 2015 and beyond.

At December 31, 2013, we had identified and engineered 241 gross (177.7 net) locations for potential future drilling on our Permian Basin acreage, primarily in the Wolfcamp or Bone Spring plays, but also including some Avalon shale 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 Permian 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. Because we have just begun the exploration of our properties in the Permian Basin in 2013, our engineered well locations at December 31, 2013 do not yet include all portions of our acreage position. Our identified well locations presume that these properties may be developed on 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. In addition, although our potential future drilling locations presume the drilling of horizontal wells, we also believe that certain portions of our acreage could lend themselves to development with vertical wells. As a result, as we explore and develop our Permian Basin acreage further, we anticipate that we may identify additional locations for future drilling. In addition, although we believe that prospective well locations exist on our acreage for the Delaware formation or other potential completion intervals, we had not included any locations for these intervals in our engineered well locations at December 31, 2013. At December 31, 2013, these potential future drilling locations included only four gross (3.4 net) locations in the Permian Basin to which we have assigned proved undeveloped reserves.

As we continue to explore and develop our leasehold positions in the Permian Basin, we may face challenges with establishing operations in new areas and securing the necessary services to drill and complete wells and with securing the necessary pipeline and natural gas processing capabilities to process, transport and market the oil and natural gas we produce. We may also incur higher than anticipated costs associated with establishing new operating infrastructure on our leases throughout the area. We believe that we have successfully secured the necessary drilling and completion services for our current Permian Basin operations, but industry activity in Southeast New Mexico and West Texas is increasing rapidly, and we may encounter difficulties in securing these services as we move forward with our exploration and development operations in this area in future periods. We believe that maintaining reliable and timely drilling and completion services, reducing drilling and completion costs and securing the necessary pipeline and natural gas processing capabilities will be essential to the successful development and profitability of the Wolfcamp, Bone Spring and other plays in the Permian Basin. 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."

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 2013, although we did participate in the drilling and completion of 11 gross (0.4 net) non-operated Haynesville shale wells. We do not plan to drill any operated Haynesville shale wells in 2014, but we have budgeted capital expenditures of approximately $12.0 million for our participation in 26 gross (1.5 net) wells that we anticipate may be drilled by other operators on certain of our non-operated properties in 2014, as well as for additional leasehold acquisition opportunities in the Haynesville shale play. Certain of these wells were already in progress at December 31, 2013. During the year ended December 31, 2013, we acquired approximately 1,190 gross (1,190 net) acres in Northwest Louisiana that we consider to be prospective primarily for natural gas production from the core area of the Haynesville shale. This acreage acquisition provides us additional operational flexibility if we resume operated activities in the Haynesville shale play in the future. At December 31, 2013, we held approximately 28,600 gross (25,800 net) acres in Northwest Louisiana and East Texas,

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including 22,700 gross (15,000 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 13,800 gross (6,900 net) acres that we consider to be in the core area of the Haynesville play.

For the year ended December 31, 2013, approximately 29% of our average daily oil equivalent production, or 3,431 BOE per day, including 17 Bbl of oil per day and 20.5 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 58% of our daily natural gas production, but oil production from these properties comprised only about 0.3% of our daily oil production during 2013, as compared to approximately 88% of our daily natural gas production and approximately 1% of our daily oil production during 2012. During the year ended December 31, 2012, approximately 56% of our average daily oil equivalent production, or 5,042 BOE per day, including 31 Bbl of oil per day and 30.1 MMcf of natural gas per day, was attributable to our properties in Northwest Louisiana and East Texas. The decline in oil and particularly natural gas production from these properties over the past year reflects (i) the natural decline in production from these properties, (ii) our decision not to drill any operated Haynesville shale or Cotton Valley wells during 2013 and (iii) the lack of drilling on these properties by our co-working interest owners in 2013.

For the year ended December 31, 2013, approximately 48% of our daily natural gas production, or 17.0 MMcf of natural gas per day, was produced from the Haynesville shale, with approximately 10%, or 3.5 MMcf of natural gas per day, produced from the Cotton Valley and other shallower formations on these properties. For the year ended December 31, 2012, approximately 76% of our daily natural gas production, or 26.0 MMcf of natural gas per day, was produced from the Haynesville shale, with approximately 12%, or 4.1 MMcf of natural gas per day, produced from the Cotton Valley and other shallower formations on these properties.

At December 31, 2013, approximately 56% of our estimated total proved reserves, or 28.8 million BOE, was attributable to the Haynesville shale with another 3% of our proved reserves, or 1.3 million BOE, attributable to the Cotton Valley and shallower formations underlying this acreage. The unweighted arithmetic average of the first-day-of-the-month natural gas price used to estimate proved natural gas reserves for 2013 increased to $3.670 per MMBtu, as compared to $2.757 per MMBtu for 2012. Primarily as a result of the continued improvement in natural gas prices over the past year, we added approximately 134.2 Bcf (22.4 million BOE) of proved undeveloped natural gas reserves in the Haynesville shale in Northwest Louisiana to our estimated total proved reserves in the second, third and fourth quarters of 2013, which are reflected in our estimated total proved reserves at December 31, 2013. We had removed 97.8 Bcf (16.3 million BOE) of previously classified proved undeveloped natural gas reserves in the Haynesville shale from our estimated total proved reserves at June 30, 2012 because the natural gas price used to estimate natural gas reserves at June 30, 2012 had declined to $3.146 per MMBtu, a price at which the natural gas volumes associated with almost all of our identified Haynesville shale well locations could no longer be classified as proved undeveloped reserves.

At December 31, 2013, we had identified and engineered 527 gross (114.5 net) locations for potential future drilling in the Haynesville shale play and 71 gross (49.3 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 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 527 gross (114.5 net) locations identified for future drilling on our Haynesville acreage, 452 gross (63.6 net) locations have been identified within the 13,800 gross (6,900 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, 2013, these potential future drilling locations included 125 gross (20.6 net) locations in the Haynesville shale (and no locations in the Cotton Valley) to which we have assigned proved undeveloped reserves. About one-third of our acreage in the core area of the Haynesville shale play in Northwest Louisiana is operated by a subsidiary of Chesapeake Energy Corporation. During the fourth quarter of 2013, we notified Chesapeake that we would be electing to take in kind the anticipated natural gas production from most of the wells operated by Chesapeake effective January 1, 2014. In addition, in December 2013, we entered into a five-year natural gas gathering agreement effective January 1, 2014 for this natural gas production. This agreement has no firm transportation commitments and no natural gas volume commitments. We believe that taking this natural gas production in kind and transporting through this gathering agreement will improve price realizations and reduce marketing and transportation fees and other costs associated with this natural gas production by an average of approximately $0.70 or more per MMBtu beginning January 1, 2014. See “Risk Factors — The Marketability of Our Production Is Dependent upon Oil and Natural Gas Gathering, Processing and Transportation Facilities

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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.”

The NYMEX Henry Hub natural gas futures contract price for the earliest delivery date was $4.38 per MMBtu at March 13, 2014. Although we do not have plans to drill any Haynesville or Cotton Valley wells on our operated properties at December 31, 2013, as a result of the recent improvement in natural gas prices, we anticipate that certain of our co-working interest owners may elect to drill additional Haynesville wells in 2014 on properties where they are the operator. As noted above, our 2014 capital expenditure budget includes our participation in 26 gross (1.5 net) non-operated Haynesville wells in 2014, several of which were already in progress at December 31, 2013. Should natural gas prices remain above $4.00 per MMBtu during a significant portion of 2014, however, we believe that we may receive proposals to participate in additional non-operated wells during 2014. Should we elect to participate in these non-operated Haynesville wells, our 2014 capital expenditure budget would most likely be increased accordingly. See “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” and “Risk Factors — We Have Limited Control over Activities on Properties We Do Not Operate.”

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.

At December 31, 2013, we had approximately 22,700 gross (15,000 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 13,800 gross (6,900 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 1,700 net acres are prospective for the Middle Bossier shale play. We have not yet 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, 2013.

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 (24.4 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 approximately one-third of our non-operated Haynesville acreage in this area of the play that is operated by a subsidiary of Chesapeake following a sale of a portion of our interest 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/Caspiana properties in Northwest Louisiana, approximately 10,000 gross (9,800 net acres) at December 31, 2013, 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 (49.3 net) additional drilling locations for future Cotton Valley horizontal wells on our Elm Grove/Caspiana properties. We did not drill any of these locations in 2013 and do not plan to drill any of these locations in 2014. 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 further, 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, 2013, we held an estimated 13,800 gross (11,400 net) leasehold and mineral acres by existing production in these areas.

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

At December 31, 2013, we held leasehold interests in approximately 76,500 gross (36,000 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, and if successful, the future development of this acreage. We are the operator of this prospect. We had no production, no proved reserves and no engineered drilling locations attributable to this acreage at December 31, 2013.

We began drilling the initial test well on this prospect, the Crawford Federal #1 well in Lincoln County, Wyoming, in February 2011. We reached a depth of 8,200 feet, approximately 300 feet above the top of the Meade Peak shale, before having operations suspended for several months due to wildlife restrictions. We resumed operations in September 2011 and completed drilling, well logging and coring operations in November 2011. During 2012, we conducted detailed evaluations of the well logs and conducted special core analysis to better understand the petrophysical characteristics of the Meade Peak shale.

In September 2012, we entered into an agreement with the principal non-operated working interest owner related to the ongoing exploration of the Meade Peak shale, pursuant to which the working interest owner (i) paid us a prospect fee of $1.0 million, (ii) agreed to provide up to a total cost of $3.0 million (carrying our 50% share) for extensions of expiring leases and new leasing in the prospect in which we will have a 50% working interest at no cost to us and (iii) agreed to carry our 50% share of the drilling and completion costs associated with the horizontal lateral up to a total cost for these operations of $5.0 million, with each party paying 50% of all drilling and completion costs in excess of $5.0 million. In return for this consideration, in December 2012, we assigned 50% of our gross and net leasehold interests in the prospect to this working interest owner.

In November 2012, we re-entered the Crawford Federal #1 vertical well and drilled a horizontal lateral from that wellbore into the Meade Peak shale approximately 2,500 feet in length. We completed the lateral with a five-stage fracture treatment in September 2013 and initiated flow back to recover the hydraulic fracture load fluid. Due to weather constraints, we have temporarily suspended our testing program for this well and plan to resume operations in 2014. We plan to evaluate this well with the other working interest owners before making further decisions concerning the future exploration of the Meade Peak shale in this prospect.

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Operating Summary

The following table sets forth certain unaudited production data for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31,		
	2013	2012	2011
Unaudited Production Data:			
Net Production Volumes:			
Oil (MBbl)	2,133	1,214	154
Natural gas (Bcf)	12.9	12.5	14.5
Total oil equivalent (MBOE) (1)	4,285	3,294	2,573
Average daily production (BOE/d) (1)	11,740	9,000	7,049
Average Sales Prices:			
Oil, with realized derivatives (per Bbl)	$98.67	$103.55	$93.80
Oil, without realized derivatives (per Bbl)	$99.79	$101.86	$93.80
Natural gas, with realized derivatives (per Mcf)	$4.47	$3.55	$4.11
Natural gas, without realized derivatives (per Mcf)	$4.35	$2.59	$3.62
Operating Expenses (per BOE):			
Production taxes and marketing	$4.89	$3.54	$2.44
Lease operating	$9.04	$8.56	$2.82
Depletion, depreciation and amortization	$22.96	$24.43	$12.34
General and administrative	$4.85	$4.42	$5.21

(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 average net daily production and total production for the year ended December 31, 2013 from our primary operating areas:

	Average Net Daily Production					
	Oil (Bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (BOE/d) (1)	Total Net Production (MBOE) (1)	Percentage of Total Net Production	
South Texas:						
Eagle Ford (2)	5,748	14,865	8,225	3,002	70.1	%
NW Louisiana/E Texas:						
Haynesville	—	16,984	2,831	1,033	24.1	%
Cotton Valley (3)	17	3,498	600	219	5.1	%
Area Total	17	20,482	3,431	1,252	29.2	%
Permian Basin:						
SE New Mexico, West Texas	78	36	84	31	0.7	%
Other:						
Wyoming, Utah, Idaho	—	—	—	—	—	
Total	5,843	35,383	11,740	4,285	100.0	%

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

(2)

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.

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

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The following table sets forth information regarding our average net daily production and total production for the year ended December 31, 2012 from our primary operating areas:

	Average Net Daily Production					
	Oil (Bbl/d)	Natural Gas (Mcf/d)	Oil Equivalent (BOE/d) (1)	Total Net Production (MBOE) (1)	Percentage of Total Net Production	
South Texas:						
Eagle Ford (2)	3,261	4,007	3,928	1,438	43.7	%
NW Louisiana/E Texas:						
Haynesville	1	26,007	4,336	1,587	48.2	%
Cotton Valley (3)	30	4,051	706	258	7.8	%
Area Total	31	30,058	5,042	1,845	56.0	%
Permian Basin:						
SE New Mexico, West Texas	25	30	30	11	0.3	%
Other:						
Wyoming, Utah, Idaho	—	—	—	—	—	
Total	3,317	34,095	9,000	3,294	100.0	%

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

(2) 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.

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

Our total production of approximately 4.3 million BOE for the year ended December 31, 2013 was an increase of 30% from our total production of approximately 3.3 million BOE for the year ended December 31, 2012. This increased production was primarily due to our drilling operations in the Eagle Ford shale. Our average daily production for the year ended December 31, 2013 was 11,740 BOE per day, as compared to 9,000 BOE per day for the year ended December 31, 2012. Our average daily oil production for the year ended December 31, 2013 was 5,843 Bbl of oil per day, an increase of 76% from 3,317 Bbl of oil per day for the year ended December 31, 2012.

Producing Wells

The following table sets forth information relating to producing wells at December 31, 2013. 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. 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
South Texas:						
Eagle Ford (1)	69	59.3	4	4.0	73	63.3
NW Louisiana/E Texas:						
Haynesville	—	—	140	13.0	140	13.0

Cotton Valley (2)	2	2.0	98	61.7	100	63.7
Area Total	2	2.0	238	74.7	240	76.7
Permian Basin:						
SE New Mexico, West Texas	12	4.4	1	0.6	13	5.0
Other:						
Wyoming, Utah, Idaho	—	—	—	—	—	—
Total	83	65.7	243	79.3	326	145.0

(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.

Estimated Proved Reserves

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The following table sets forth our estimated proved oil and natural gas reserves at December 31, 2013, 2012 and 2011. 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 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.

	At December 31, (1)		
	2013	2012	2011
Estimated Proved Reserves Data: (2)			
Estimated proved reserves:			
Oil (MBbl)	16,362	10,485	3,794
Natural Gas (Bcf) (3)	212.2	80.0	170.4
Total (MBOE) (4)	51,729	23,819	32,196
Estimated proved developed reserves:			
Oil (MBbl)	8,258	4,764	1,419
Natural Gas (Bcf) (3)	53.5	54.0	56.5
Total (MBOE) (4)	17,168	13,771	10,843
Percent developed	33.2 %	57.8 %	33.7 %
Estimated proved undeveloped reserves:			
Oil (MBbl)	8,104	5,721	2,375
Natural gas (Bcf) (3)	158.7	26.0	113.9
Total (MBOE) (4)	34,561	10,048	21,353
PV-10 (5) (in millions)	$655.2	$423.2	$248.7
Standardized Measure (6) (in millions)	$578.7	$394.6	$215.5

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(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, 2013 were $93.42 per Bbl for oil and $3.670 per MMBtu for natural gas, for the 12 months ended December 31, 2012 were $91.21 per Bbl for oil and $2.757 per MMBtu for natural gas, and for the 12 months ended December 31, 2011 were $92.71 per Bbl for oil and $4.118 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 2012, at June 30, 2012, we removed 97.8 Bcf (16.3 million BOE) of previously classified proved undeveloped natural gas reserves in the Haynesville shale from our total

proved reserves, most of which were attributable to non-operated properties. Primarily as a result of the continued improvement in natural gas prices during 2013, we added approximately 134.2 Bcf (22.4 million BOE) of proved undeveloped natural gas reserves in the Haynesville shale to our estimated total proved reserves in the second, third and fourth quarters of 2013, which are reflected in our estimated total proved reserves at December 31, 2013.

(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, 2013, 2012 and 2011 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, 2013, 2012 and 2011 were, in millions, \$76.5, \$28.6 and \$33.2, 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.

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Our estimated total proved oil and natural gas reserves increased 117% from 23.8 million BOE at December 31, 2012 to 51.7 million BOE at December 31, 2013. Our proved oil reserves grew 56% from approximately 10.5 million Bbl at December 31, 2012 to approximately 16.4 million Bbl at December 31, 2013. This increase is primarily attributable to proved oil reserves added due to our drilling operations in the Eagle Ford shale in South Texas. Our proved natural gas reserves increased 165% from 80.0 Bcf at December 31, 2012 to 212.2 Bcf at December 31, 2013. This increase in our proved natural gas reserves was attributable to our drilling and completion activities in 2013 and to the increase in our proved undeveloped natural gas reserves in 2013 from 26.0 Bcf at December 31, 2012 to 158.7 Bcf at December 31, 2013 due primarily to higher natural gas prices. As a result of substantially lower natural gas prices in 2012, we removed 97.8 Bcf (16.3 million BOE) of previously classified proved undeveloped natural gas reserves in the Haynesville shale from our total proved reserves at June 30, 2012, most of which were attributable to non-operated properties. These proved undeveloped natural gas reserves were likewise not included in our estimated total proved reserves at December 31, 2012. During 2013, primarily as a result of continued improvement in natural gas prices during the year, we added approximately 134.2 Bcf (22.4 million BOE) of proved undeveloped natural gas reserves in the Haynesville shale to our estimated total proved reserves in the second, third and fourth quarters of 2013, which are reflected in our estimated total proved reserves at December 31, 2013. The PV-10 of our total proved oil and natural gas reserves increased by 55% from $423.2 million at December 31, 2012 to $655.2 million at December 31, 2013. Our total proved reserves at December 31, 2013 were made up of approximately 32% oil and 68% natural gas, as compared to 44% oil and 56% natural gas at December 31, 2012.

Our proved developed oil and natural gas reserves increased from 13.8 million BOE at December 31, 2012 to 17.2 million BOE at December 31, 2013 due primarily to additions resulting from our drilling operations in the Eagle Ford shale. Our proved developed oil reserves increased from 4.8 million Bbl at December 31, 2012 to 8.3 million Bbl at December 31, 2013 as a result of our drilling operations in the Eagle Ford shale. Our proved developed natural gas reserves decreased slightly from 54.0 Bcf at December 31, 2012 to 53.5 Bcf at December 31, 2013 due primarily to declining natural gas production in the Haynesville shale and Cotton Valley coupled with the fact that we did not drill any operated Haynesville shale or Cotton Valley wells on our operated properties during 2013 and likewise, our co-working interest owners drilled very few Haynesville shale wells on the properties they operate.

The following table summarizes changes in our estimated proved developed reserves at December 31, 2013.

	Proved Developed Reserves (MBOE) [1]
As of December 31, 2012	13,771
Extensions and discoveries	3,971
Purchases of minerals-in-place	28
Revisions of prior estimates	(651)
Production	(4,285)
Conversion of proved undeveloped to proved developed	4,334
As of December 31, 2013	17,168

(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 10.0 million BOE at December 31, 2012 to 34.6 million BOE at December 31, 2013. Our proved undeveloped oil reserves increased from 5.7 million Bbl at December 31, 2012 to 8.1 million Bbl at December 31, 2013, primarily as a result of our drilling operations in the Eagle Ford shale. Our proved undeveloped natural gas reserves increased from 26.0 Bcf at December 31, 2012 to 158.7 Bcf at December 31, 2013 due primarily to the previously discussed addition of approximately 134.2 Bcf (22.4 MBOE) of proved undeveloped natural gas reserves in the Haynesville shale to our estimated total proved reserves in the second, third and fourth quarters of 2013, which is reflected in our estimated total proved reserves at December 31, 2013.

At December 31, 2013, we had no proved reserves in our estimates that remained undeveloped for five years or more following their booking.

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The following table summarizes changes in our estimated proved undeveloped reserves at December 31, 2013.

	Proved Undeveloped Reserves (MBOE) [1]
As of December 31, 2012	10,048
Extensions and discoveries	15,260
Purchases of minerals-in-place	—
Revisions of prior estimates	13,587
Conversion of proved undeveloped to proved developed	(4,334)
As of December 31, 2013	34,561

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

The following table sets forth, since 2011, 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 (MBbl)	Natural Gas (Bcf)	Total (MBOE) [1]	
2011	—	3.4	573	$ 1,409
2012	283	0.8	415	8,096
2013	2,944	8.3	4,334	115,699
Total	3,227	12.5	5,322	$ 125,204

(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, 2013:

	Net Proved Reserves [1]				
	Oil (MBbl)	Natural Gas (Bcf)	Oil Equivalent (MBOE) [4]	PV-10 [2] (in millions)	Standardized Measure [3] (in millions)
South Texas:					
Eagle Ford [5]	15,198	30.1	20,221	$540.4	$477.3
NW Louisiana/E Texas:					
Haynesville	—	172.8	28,797	74.7	66.0
Cotton Valley [6]	36	7.8	1,339	8.2	7.2
Area Total	36	180.6	30,136	82.9	73.2
Permian Basin:					
SE New Mexico, West Texas	1,128	1.5	1,372	31.9	28.2
Other:					
Wyoming, Utah, Idaho	—	—	—	—	—
Total	16,362	212.2	51,729	$655.2	$578.7

(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,

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2013 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, 2013 were approximately $76.5 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 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.

(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 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 Vice President – Reservoir Engineering 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 36 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 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.

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Acreage Summary

The following table sets forth the approximate acreage in which we held a leasehold, mineral or other interest at December 31, 2013.

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
South Texas:						
Eagle Ford	22,604	18,206	16,381	8,941	38,985	27,147
NW Louisiana/E Texas:						
Haynesville	18,960	11,238	3,734	3,731	22,694	14,969
Cotton Valley	20,510	18,418	3,916	3,403	24,426	21,821
Area Total (1)	24,215	21,885	4,392	3,876	28,607	25,761
Permian Basin:						
SE New Mexico, West Texas	1,120	897	69,699	43,937	70,819	44,834
Other:						
Wyoming, Utah, Idaho	—	—	76,496	36,004	76,496	36,004
Total	47,939	40,988	166,968	92,758	214,907	133,746

(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, 2013 that will expire prior to December 31, 2015 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.

	Acres Expiring 2014		Acres Expiring 2015	
	Gross	Net	Gross	Net
South Texas:				
Eagle Ford	2,879	846	2,343	1,777
NW Louisiana/E Texas:				
Haynesville	11	11	—	—
Cotton Valley	11	11	—	—
Area Total (1)	11	11	—	—
Permian Basin:				
SE New Mexico, West Texas	7,775	706	5,496	2,439
Other:				
Wyoming, Utah, Idaho	—	—	—	—
Total	10,665	1,563	7,839	4,216

(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.

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. Our leases are mainly fee leases with primary terms of three to five years. We believe that our lease terms are similar to our competitors' fee lease terms as they relate to both primary term and royalty interests.

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Drilling Results

The following table summarizes our drilling activity for the years ended December 31, 2013, 2012 and 2011:

	Year Ended December 31,					
	2013		2012		2011	
	Gross	Net	Gross	Net	Gross	Net
Development Wells						
Productive	32	20.7	36	17.1	30	0.6
Dry	—	—	—	—	—	—
Exploration Wells						
Productive	14	8.7	22	10.4	30	10.2
Dry (1)	1	0.4	—	—	—	—
Total Wells						
Productive	46	29.4	58	27.5	60	10.8
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.

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, weather conditions, hurricanes in the Gulf Coast region, natural gas storage levels, domestic and foreign governmental regulations, the actions of OPEC, 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 do 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 do 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, 2013, we had five significant purchasers that accounted for approximately 87% of our total oil, natural gas and natural gas liquids revenues. For the years ended December 31, 2012 and 2011, we had three significant purchasers that accounted for approximately 74% and 60%, 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.

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About one-third of our acreage in the core area of the Haynesville shale play in Northwest Louisiana is operated by a subsidiary of Chesapeake Energy Corporation. During the fourth quarter of 2013, we notified Chesapeake that we would be electing to take in kind the anticipated natural gas production from most of the wells operated by Chesapeake effective January 1, 2014. In addition, we entered into a five-year natural gas gathering agreement effective January 1, 2014 for this anticipated natural gas production. This agreement has no firm transportation commitments and no natural gas volume commitments. We believe that taking our natural gas production in kind and transporting through this gathering agreement will improve price realizations and reduce marketing and transportation fees and other costs associated with this natural gas production by an average of approximately $0.70 or more per MMBtu. 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."

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 periods, we had an immaterial natural gas deficiency and the counterparty to this agreement has agreed to waive 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."

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. Most 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."

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 and 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.

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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.

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 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.

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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

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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. Before January 1, 2015, these standards require owners/operators to reduce volatile organic compound (“VOC”) emissions from natural gas not sent to the gathering line during well completion either by flaring using a completion combustion device or by capturing the natural gas using green completions with a completion combustion device. Beginning 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 new 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. We continue to evaluate the effect these rules have on our business and operations, which effects we do not expect to be material.

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 position, 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. Any future 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, on October 30, 2009, the EPA published a rule requiring the reporting of greenhouse gas emissions from specified sources in the United States beginning in 2011 for emissions occurring in 2010. On November 30, 2010, the EPA released a rule that expands its final rule on greenhouse gas emissions reporting to include owners and operators of onshore and offshore oil and natural gas production, onshore natural gas processing, natural gas storage, natural gas transmission and natural gas distribution facilities. Reporting of greenhouse gas emissions from such onshore 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.

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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. We currently own and operate five underground injection wells and expect to own other similar wells. 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.

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, in some states and localities, there has been a push to place additional regulatory burdens upon hydraulic fracturing activities and, in some areas, to severely restrict or prohibit those activities. At the state level, Texas 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 local governments or regional authorities have imposed temporary moratoria on drilling permits within city limits so that local ordinances may be reviewed to assess their adequacy to address hydraulic fracturing activities. Additional burdens upon hydraulic fracturing, such as reporting or permitting requirements, will result in additional expense and delay in our operations.

The EPA has recently asserted federal regulatory authority over hydraulic fracturing using diesel under the SDWA's Underground Injection Control Program. The EPA recently 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, the EPA is currently conducting a study on the effects of hydraulic fracturing on drinking water resources. A progress report was released in December 2012, with draft final results expected in 2014. Further, the BLM has proposed rules to regulate hydraulic fracturing on federal lands. The EPA has also announced an initiative 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-

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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.

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. If a portion of our leases were designated as critical or suitable habitat, our ability to maximize production from our leases may be adversely impacted.

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 position. 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. In April 2013, we entered into the fifth amendment to our office lease agreement. This amendment increased the square footage of our corporate headquarters to 40,071 square feet effective July 1, 2013. The lease expires on June 30, 2022.

Employees

At December 31, 2013, we had 66 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.

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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 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. 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.

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. The prices we receive for our production, and the levels of our production, depend on numerous factors. These factors include the following:

- the domestic and foreign supply of oil and natural gas;
- the domestic and foreign demand for oil and natural gas;
- the prices and availability of competitors’ supplies of 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 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, including the Middle East and South America;
- the continued threat of terrorism and the impact of military action and civil unrest;
- 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.

Approximately 50% of our production during the year ended December 31, 2013 and 68% of our proved reserves at December 31, 2013 were attributable to natural gas. In addition, three of our significant assets or prospects — the Haynesville

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shale, Cotton Valley and Meade Peak shale — currently produce or are expected to produce predominantly natural gas. As a result, they are sensitive to fluctuations in natural gas prices.

During 2013, natural gas prices began the year with a low of approximately $3.11 per MMBtu in early January, climbed to approximately $4.41 per MMBtu in late April and fell back to approximately $3.23 per MMBtu in early August before reaching a 2013 high of approximately $4.46 per MMBtu in late December, based upon the NYMEX Henry Hub natural gas futures contract price for the earliest delivery date. Natural gas prices climbed to above $6.00 per MMBtu in early 2014 and settled at $4.38 per MMBtu at March 13, 2014, based upon the NYMEX Henry Hub natural gas futures contract for the earliest delivery date. Although we do not expect to drill any operated natural gas wells in the Haynesville shale or Cotton Valley in 2014, given the recent improvement in natural gas prices, we anticipate that certain of our co-working interest owners may drill natural gas wells, and in particular Haynesville shale wells, on properties they operate. We expect to be offered the opportunity to participate, and most likely will participate, in these non-operated natural gas wells.

In 2011, we began to focus on increasing our oil and liquids production. Specifically, our drilling opportunities in the Eagle Ford shale play in South Texas and in the Wolfcamp and Bone Spring plays in the Permian Basin in Southeast New Mexico and West Texas focus on oil and liquids. Approximately 50% of our production during the year ended December 31, 2013 and 32% of our proved reserves at December 31, 2013 were attributable to oil. We currently intend to allocate approximately 97% of our 2014 capital expenditure budget to opportunities prospective for oil and liquids production, including primarily the Eagle Ford shale and the Wolfcamp and Bone Spring plays. These opportunities are sensitive to changes in oil prices. For the year ended December 31, 2013, oil prices ranged from a low of approximately $86.68 per Bbl in mid-April to a high of approximately $110.53 per Bbl in early September, based upon the NYMEX West Texas Intermediate oil futures contract price for the earliest delivery date.

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 prices decrease to economically unattractive levels and remain there 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 (as we have done with our operated natural gas properties in recent years), each of which would have a material adverse effect on our business, financial condition, results of operations and reserves. 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.

Drilling for and Producing Oil and Natural Gas Are Highly Speculative and Involve a High Degree of 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 the drilling, completing and operating processes. Before a well is spud, we may incur significant geological and geophysical (seismic) costs, which are incurred whether 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 predict 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;
- 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.

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.

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 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. Although we currently have no plans to do so, we may sell additional equity securities or issue debt securities to raise capital. If we succeed in selling additional equity securities or securities convertible into equity securities to raise funds, 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 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 decrease as a result of lower oil and natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels, further develop and exploit our current properties or invest in certain exploration opportunities. Alternatively, to fund an acquisition, 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 non-strategic 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.

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

At March 13, 2014, we had available borrowings of approximately $134.7 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 acquired 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 substantially all of our interests in 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, we may incur significant amounts of additional indebtedness, including under our Credit Agreement, 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;
- impairing 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 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.

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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.

We May Have Accidents, Equipment Failures or Mechanical Problems While Drilling or Completing Wells or in Production Activities, Which Could Adversely Affect Our Business.

While we are drilling and completing oil or natural gas wells or involved in production activities, we may have accidents or experience equipment failures or mechanical problems in a well that cause us to be unable to drill and complete the well or to continue to produce the well according to our plans. We may also damage a potentially hydrocarbon-bearing formation during drilling and completion operations. Such incidents may result in a reduction of our production and reserves from, or abandonment of, the well, and the costs associated with remedying such accidents 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 Small Number of Properties, Problems in Production and Markets Relating to Any Property 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 South Texas and in Northwest Louisiana and East Texas. For the year ended December 31, 2013, approximately 70% of our oil and natural gas production, including approximately 98% of our average daily oil production, was attributable to our properties in South Texas. At December 31, 2013, approximately 82% of the PV-10 of our proved reserves and approximately 93% of our total proved oil reserves were attributable to our properties in South Texas, primarily in the Eagle Ford shale. We expect that most of our operations in the near future will be primarily in South Texas. In addition, we expect to direct approximately 25% of our 2014 capital expenditure budget to further evaluating our acreage position in the Permian Basin in Southeast New Mexico and West Texas.

The industry focus on the Eagle Ford shale and the Permian Basin 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. Even though we have entered into a firm five-year 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, 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 exploration and drilling, 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 quarter of 2013, the Permian 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. Although we did not experience any material delays or other issues as a result of inclement weather in this area, as we increase our operations and

production in the Permian 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. Such delays or interruptions could have a material adverse effect on our financial condition, results of operations and cash flows.

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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 vendors to the industry. 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, 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. 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 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 Eagle Ford shale and the Permian Basin, areas 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 these areas 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;

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- the judgment of the persons preparing the estimate; and
- the accuracy of the assumptions used.

The accuracy of any estimates of proved 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. We generally base the estimated discounted future net cash flows from proved reserves 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 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 68% of Our Total Proved Reserves at December 31, 2013 Consisted of Undeveloped and Developed Non-Producing Reserves, and Those Reserves May Not Ultimately Be Developed or Produced.

At December 31, 2013, approximately 67% of our total proved reserves were undeveloped and approximately 1% 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 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 assessment of risks, costs, drilling results, oil and natural gas prices, the availability of equipment and capital, approval by regulators 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, 2013, we had leasehold interests in approximately 5,800 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, 2015. 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.

We May Not Increase Our Acreage Positions in Areas with Exposure to Oil, Condensate and Natural Gas Liquids.

If we are unable to locate or consummate acquisition opportunities and increase our acreage positions in the Eagle Ford shale in South Texas, the Permian Basin in Southeast New Mexico and West Texas or other areas with similar exposure to oil, condensate and natural gas liquids, we may not realize our growth strategy in oil and liquids-rich plays. The inability to realize our growth strategy and increase our acreage positions in these areas 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. 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.

We Currently Own Only a Limited Amount of Seismic and Other Geological Data and May Have Difficulty Obtaining Additional Data at a Reasonable Cost, Which Could Adversely Affect Our Results of Operations and Cash Flows.

We currently own only a limited amount of seismic and other geological data to assist us in exploration and development activities. We intend to obtain access to additional data in our areas of interest through licensing arrangements with companies that own or have access to that data or by paying to obtain that data directly. Seismic and geological data can be expensive to license or obtain. We may not be able to license or obtain such data at an acceptable cost, which could negatively 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.

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 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.

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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. 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 Would 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 Permian 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 covering the anticipated natural gas production from a significant portion of our Eagle Ford shale acreage in South Texas, no assurance can be given that this agreement will alleviate these issues completely, and we may be required to pay deficiency payments under this agreement if we do not meet the thermal quantity transportation and processing commitments under this agreement. We may experience similar interruptions and processing capacity constraints as we continue to explore and develop our Wolfcamp and Bone Spring plays in the Permian Basin in 2014. 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 would have a material adverse effect on our business, financial condition, results of operations and cash flows.

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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 essentially all 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. 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.

The Third Parties on Whom We Rely for 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 are subject to complex and stringent laws and regulations that require obtaining and maintaining numerous permits, approvals and certifications from various federal, state and local government authorities. These third parties may incur substantial costs in order to comply with existing laws and regulations. If existing laws and regulations governing such third party services are revised or reinterpreted, or if new laws and regulations become applicable to their operations, these changes may affect the costs that we pay for such services. Similarly, a failure to comply with such laws and regulations by the third parties on whom we rely could have a material adverse effect on our business, financial condition, 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 a subsidiary of Chesapeake Energy Corporation 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;