Gastar Exploration Inc.
Form 10-K
March 12, 2015
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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

(Mark One)

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

or

o 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: 001-35211

GASTAR EXPLORATION INC.

(Exact name of registrant as specified in its charter)

Delaware (State or other jurisdiction of incorporation or organization)	38-3531640 (I.R.S. Employer Identification No.)
1331 Lamar Street, Suite 650 Houston, Texas (Address of principal executive offices)	77010 (Zip Code)

(713) 739-1800
(Registrant's telephone number, including area code)

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

Title of each class	Name of exchange on which registered
Common Stock, par value $0.001 per share	NYSE MKT LLC
8.625% Series A Cumulative Preferred Stock, par value $0.01 per share	NYSE MKT LLC
10.75% Series B Cumulative Preferred Stock, par value $0.01 per share	NYSE MKT LLC

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 by 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 (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter)
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 the 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	¨	Smaller reporting company	¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934).
Yes ¨ No ý

The aggregate market value of the voting and non-voting common equity of Gastar Exploration Inc. held by non-affiliates of Gastar Exploration Inc. as of June 30, 2014 (the last business day of Gastar Exploration Inc.'s most recently completed second fiscal quarter) was approximately $507.9 million based on the closing price of $8.71 per share on the NYSE MKT LLC.

The total number of shares of common stock, par value $0.001 per share, outstanding as of March 11, 2015 was 80,195,695.

DOCUMENTS INCORPORATED BY REFERENCE:
None.

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GASTAR EXPLORATION INC. AND SUBSIDIARIES
ANNUAL REPORT ON FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2014
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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (this "Form 10-K") contains "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act of 1933, as amended (the "Securities Act"), and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements other than statements of historical fact included or incorporated by reference in this Form 10-K are forward-looking statements, including, without limitation, all statements regarding future plans, business objectives, strategies, expected future financial position or performance, future covenant compliance, expected future operational position or performance, budgets and projected costs, future competitive position or goals and/or projections of management for future operations. In some cases, you can identify a forward-looking statement by terminology such as "may," "will," "could," "should," "expect," "plan," "project," "intend," "anticipate," "believe," "estimate," "predict," "poter or "continue," the negative of such terms or variations thereon, or other comparable terminology.

The forward-looking statements contained in this Form 10-K are largely based on our expectations and beliefs concerning future developments and their potential effect on us, which reflect certain estimates and assumptions made by our management. These estimates and assumptions reflect our best judgment based on currently known market conditions, operating trends and other factors. Forward-looking statements may include statements that relate to, among other things, our:

- financial position;
- business strategy and budgets;
- capital expenditures;
- drilling of wells, including the scheduling and results of such operations;
- oil, natural gas and natural gas liquids ("NGLs") reserves;
- timing and amount of future production of oil, condensate, natural gas and NGLs;
- operating costs and other expenses;
- cash flow and liquidity;
- compliance with covenants under our indenture and credit agreements;
- availability of capital;
- prospect development; and
- property acquisitions and sales.

Although we believe such estimates and assumptions to be reasonable, they are inherently uncertain and involve a number of risks and uncertainties that are beyond our control. As such, management's assumptions about future events may prove to be inaccurate. For a more detailed description of the known material factors that could cause actual results to differ from those in the forward-looking statements, see Item 1A. "Risk Factors" in Part I of this Form 10-K. We do not intend to publicly update or revise any forward-looking statements as a result of new information, future events, changes in circumstances or otherwise. These cautionary statements qualify all forward-looking statements attributable to us, or persons acting on our behalf. Management cautions all readers that the forward-looking statements contained in this Form 10-K are not guarantees of future performance, and we cannot assure any reader that such statements will be realized or that the events and circumstances they describe will occur. Factors that could cause actual results to differ materially from those anticipated or implied in the forward-looking statements herein include, but are not limited to:

- the supply and demand for oil, condensate, natural gas and NGLs;
- continued low or further declining prices for oil, condensate, natural gas and NGLs;
- worldwide political and economic conditions and conditions in the energy market;
- the extent to which we are able to realize the anticipated benefits from acquired assets;
- our ability to raise capital to fund capital expenditures or repay or refinance debt upon maturity;
- our ability to meet financial covenants under our indenture or credit agreements or the ability to obtain amendments or waivers to effect such compliance;
- the ability and willingness of our current or potential counterparties, third-party operators or vendors to enter into transactions with us and/or to fulfill their obligations to us;

- failure of our joint interest partners to fund any or all of their portion of any capital program;
- the ability to find, acquire, market, develop and produce new oil and natural gas properties;

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- uncertainties about the estimated quantities of oil and natural gas reserves and in the projection of future rates of production and timing of development expenditures of proved reserves;
- strength and financial resources of competitors;
- availability and cost of material and equipment, such as drilling rigs and transportation pipelines;
- availability and cost of processing and transportation;
- changes or advances in technology;
- the risks associated with exploration, including cost overruns and the drilling of non-economic wells or dry wells, operating hazards inherent to the natural gas and oil business and down hole drilling and completion risks that are generally not recoverable from third parties or insurance;
- potential mechanical failure or under-performance of significant wells or pipeline mishaps;
- environmental risks;
- possible new legislative initiatives and regulatory changes potentially adversely impacting our business and industry, including, but not limited to, national healthcare, hydraulic fracturing, state and federal corporate income taxes, retroactive royalty or production tax regimes, changes in environmental regulations, environmental risks and liability under federal, state and local environmental laws and regulations;
- effects of the application of applicable laws and regulations, including changes in such regulations or the interpretation thereof;
- potential losses from pending or possible future claims, litigation or enforcement actions;
- potential defects in title to our properties or lease termination due to lack of activity or other disputes with mineral lease and royalty owners, whether regarding calculation and payment of royalties or otherwise;
- the weather, including the occurrence of any adverse weather conditions and/or natural disasters affecting our business;
- our ability to find and retain skilled personnel; and
- any other factors that impact or could impact the exploration of natural gas or oil resources, including, but not limited to, the geology of a resource, the total amount and costs to develop recoverable reserves, legal title, regulatory, natural gas administration, marketing and operational factors relating to the extraction of natural gas and oil.

You should not unduly rely on these forward-looking statements in this Form 10-K, as they speak only as of the date of this Form 10-K. Except as required by law, we undertake no obligation to publicly update, revise or release any revisions to these forward-looking statements after the date on which they are made to reflect new information, events or circumstances occurring after the date of this Form 10-K or to reflect the occurrence of unanticipated events.

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On November 14, 2013, Gastar Exploration Ltd., an Alberta, Canada corporation, changed its jurisdiction of incorporation to the State of Delaware and changed its name to "Gastar Exploration, Inc." On January 31, 2014, Gastar Exploration, Inc. merged with and into Gastar Exploration USA, Inc., its direct subsidiary, as part of a reorganization to eliminate Gastar Exploration, Inc.'s holding company corporate structure. Pursuant to the merger agreement, shares of Gastar Exploration, Inc.'s common stock were converted into an equal number of shares of common stock of Gastar Exploration USA, Inc., and Gastar Exploration USA, Inc. changed its name to "Gastar Exploration Inc." Gastar Exploration Inc., together with its subsidiary, owns and continues to conduct Gastar Exploration, Inc.'s business in substantially the same manner as was being conducted prior to the merger.

Unless otherwise indicated or required by the context, (i) for any date or period prior to the January 31, 2014 merger described above,"Gastar," the "Company," "we," "us," "our" and similar terms refer collectively to Gastar Exploration, Inc.(formerly known as Gastar Exploration Ltd.) and its subsidiaries, including Gastar Exploration Inc. (formerly known as Gastar Exploration USA, Inc.), and for any date or period after January 31, 2014, such terms refer collectively to Gastar Exploration Inc. and its subsidiaries, (ii) "Gastar USA" refers to Gastar Exploration USA, Inc., which until January 31, 2014 was a first-tier subsidiary of Gastar Exploration, Inc. and its primary operating company, (iii) "Parent" refers to Gastar Exploration, Inc., (iv) all dollar amounts appearing in this Form 10-K are stated in United States dollars ("U.S. dollars") unless otherwise noted and (v) all financial data included in this Form 10-K have been prepared in accordance with generally accepted accounting principles in the United States of America ("U.S. GAAP").

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Glossary of Terms

AMI	Area of mutual interest, an agreed designated geographic area where joint venturers or other industry partners have a right of participation in acquisitions and operations
Bbl	Barrel of oil, condensate or NGLs
Bbl/d	Barrels of oil, condensate or NGLs per day
Bcf	One billion cubic feet of natural gas
Bcfe	One billion cubic feet of natural gas equivalent, determined using the ratio of six thousand cubic feet of natural gas to one barrel of oil, condensate or NGLs
Boe	One barrel of oil equivalent determined using the ratio of six thousand cubic feet of natural gas to one barrel of oil, condensate or NGLs
Boe/d	Barrels of oil equivalent per day
Btu	British thermal unit, typically used in measuring natural gas energy content
CRP	Central receipt point
FASB	Financial Accounting Standards Board
GAAP	Accounting principles generally accepted in the United States of America
Gross acres	Refers to acres in which we own a working interest
Gross wells	Refers to wells in which we have a working interest
MBbl	One thousand barrels of oil, condensate or NGLs
MBbl/d	One thousand barrels of oil, condensate or NGLs per day
MBoe	One thousand barrels of oil equivalent, calculated on the assumed energy equivalent basis of 6 Mcf of natural gas per MBoe
MBoe/d	One thousand barrels of oil equivalent per day
Mcf	One thousand cubic feet of natural gas
Mcf/d	One thousand cubic feet of natural gas per day
Mcfe	One thousand cubic feet of natural gas equivalent, calculated on the assumed energy equivalent basis of 1/6 of a barrel of oil per Mcfe
MMBtu/d	One million British thermal units per day

MMcf	One million cubic feet of natural gas
MMcf/d	One million cubic feet of natural gas per day
MMcfe	One million cubic feet of natural gas equivalent, calculated on the assumed energy equivalent basis of 1/6 of a barrel of oil per Mcfe
MMcfe/d	One million cubic feet of natural gas equivalent per day, calculated on the assumed energy equivalent basis of 1/6 of a barrel of oil per Mcfe
Net acres	Refers to our proportionate interest in acreage resulting from our ownership in gross acreage
Net wells	Refers to gross wells multiplied by our working interest in such wells
NGLs	Natural gas liquids
NYMEX	New York Mercantile Exchange
PBU	Performance based unit
psi	Pounds per square inch
U.S.	United States

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PART I

Item 1. Business

Overview

We are an independent energy company engaged in the exploration, development and production of oil, condensate, natural gas and NGLs in the U.S. Our principal business activities include the identification, acquisition, and subsequent exploration and development of oil and natural gas properties with an emphasis on unconventional reserves, such as shale resource plays. In Oklahoma, we are developing the primarily oil-bearing reservoirs of the Hunton Limestone horizontal oil play and expect to test other prospective formations on the same acreage, including the Woodford Shale and the Meramec Shale (middle Mississippi Lime), which we refer to as the Stack Play. In West Virginia, we are developing liquids-rich natural gas in the Marcellus Shale and have drilled our first successful dry gas Utica Shale/Point Pleasant well on our acreage. We completed the sale of substantially all of our East Texas assets in 2013.

Shares of our common stock are listed on the NYSE MKT LLC under the symbol “GST,” shares of our 8.625% Series A Cumulative Preferred Stock are listed on the NYSE MKT LLC under the symbol “GST.PRA” and shares of our 10.75% Series B Cumulative Preferred Stock are listed on the NYSE MKT LLC under the symbol “GST.PRB”. Our principal office is located at 1331 Lamar Street, Suite 650, Houston, Texas 77010, and our telephone number is (713) 739-1800. Our website address is http://www.gastar.com. Information on our website or about us on any other website is not incorporated by reference into and does not constitute part of this Form 10-K.

Our Strategy

Our strategy is to increase stockholder value by delivering sustainable reserves growth and improved operating results from our existing assets. We recognize that there may be periods, such as the recent decline in oil and natural gas prices, which make it difficult to fully execute this strategy on a short-term basis. We intend to implement our strategy by focusing on:

- exploitation and development of our Mid-Continent assets in the Hunton Limestone horizontal oil play;
- continued exploitation of existing Marcellus Shale assets with a focus on areas that we believe are prospective for natural gas with relatively high condensate and NGLs content;
- additional testing of the Utica Shale;
- active management of our domestic drilling programs; and
- effective management and utilization of technological expertise.

Exploitation and Development in the Hunton Limestone Horizontal Oil Play

During 2012, we began acquiring leasehold in an emerging oil play located in Oklahoma. We continued to build our acreage position in this region during 2013 and 2014 in partnership with our operating partner in the initial AMI prospect area and two additional adjacent prospect areas. We also increased our exposure within the play through acquisitions of acreage and producing wells from subsidiaries of Chesapeake Energy Corporation and certain entities affiliated with its former chief executive officer (the “Chesapeake Parties”) and affiliates of Lime Rock Resources (the “Lime Rock Parties”), respectively, during 2013. Our Mid-Continent development program is focused on using modern horizontal drilling and multi-stage fracture stimulation technologies to exploit a predominantly crude oil-bearing reservoir, which has been produced historically using vertical wells with conventional completion techniques. We, along with our operating partner in the initial AMI and adjacent areas, drilled and completed one gross (0.5 net) horizontal non-operated well during 2012, drilled and completed six gross (3.0 net) horizontal non-operated wells during 2013 and drilled and completed 22 gross (9.8 net) horizontal non-operated wells during 2014 on our Mid-Continent properties. Additionally, during 2013, we began our operated drilling program in the Hunton Limestone with our first two gross (1.8 net) operated wells drilled and completed in the lower Hunton Limestone. During 2014, we drilled and completed seven gross (6.8 net) operated horizontal wells, which includes four gross (3.9 net) wells within the West Edmond Hunton Lime Unit (“WEHLU”). To further test the potential of the formation, we have also participated in three gross (0.4 net) wells outside of our AMI acreage targeting the Hunton Limestone. We are awaiting the completion of two gross (0.1 net) non-operated wells in the Woodford Shale. Prior to 2014, we participated in a total of two gross (0.1 net) non-operated wells testing the Stack Play potential in the Woodford Shale and the Meramec Shale (middle Mississippi Lime) formations. Production results from these Stack Play wells were below our expectations.

We intend to focus the majority of our 2015 capital budget on drilling existing leasehold, leasehold renewal and leasehold acquisition in the Mid-Continent, with approximately 67% of our 2015 capital budget allocated to developing or maintaining our Hunton Limestone properties. Our 2015 capital budget allocated to the Mid-Continent includes plans to spud a total of 14 gross (12.2 net) wells, comprised of three gross (1.4 net) non-operated wells primarily located within our current AMI and 11 gross (10.8 net) operated WEHLU wells. We anticipate completing a total of 21 gross (16.2 net) wells in the Hunton Limestone during 2015, comprised of eight gross (3.4 net) non-operated wells primarily located within our current AMI and 13 gross (12.8 net) operated WEHLU wells.

Continue Exploitation of Existing Marcellus Shale Assets and Focus on Areas with Relatively High NGLs and Condensate Content along with Further Testing of High Rate Dry Gas Potential in the Utica Shale.

Due to recent declines in natural gas and NGLs prices in the Appalachian Basin, our 2015 capital program will be limited to completion of certain previously drilled wells. Approximately 26% of our 2015 capital budget is dedicated to Marcellus Shale and Utica well completions and projected purchase of certain additional mineral rights under certain existing acreage. Our 2015 capital budget currently includes plans to complete seven gross (3.5 net) wells in the Marcellus Shale and one gross (0.5 net) well in the Utica Shale. Should well costs decline or net realized prices increase sufficiently, we may elect to expand drilling operations in the area. Our focus continues to be drilling to hold the acreage by production prior to lease term expirations.

Additional Testing of the Utica Shale.

In April 2014, we commenced exploration in the Utica Shale in West Virginia. As anticipated, our initial Utica Shale well, the Simms U-5H, resulted in production of dry natural gas at high delivery rates and levels that may generate attractive internal rates of return despite the absence of liquids. The Simms U-5H was drilled to a total vertical depth of 11,500 feet and with an approximate 4,400-foot lateral and completed with a 25-stage fracture stimulation. The Simms U-5H was producing at a last five-day average rate of 9.1 MMcf/d of natural gas and had total cumulative production of 2.1 Bcf as of February 28, 2015. We spudded our second Utica Shale well, the Blake U-7H, in late November 2014 and completed drilling of the well by mid-December 2014. We currently project that the Blake U-7H will be on production in May 2015.

Actively Manage Our Domestic Drilling Program

We believe that operating approximately 92% of our drilling projects budgeted for 2015 will enable us to control the timing and cost of our drilling as well as control operating costs and the marketing of our production. Cost control is increasingly more important given the current commodity price environment and market conditions. We believe that we have assembled an experienced team of operating professionals with the specialized skills needed to plan and execute the drilling and completion of horizontal Hunton Limestone, Marcellus Shale and Utica Shale wells.

Manage and Utilize Technological Expertise

We believe that micro-seismic data acquisition and interpretation, enhanced natural gas recovery processes, horizontal drilling and other advanced drilling, formation evaluation and production techniques are valuable tools that improve drilling results and ultimately enhance production and returns. We believe that utilizing these technologies and production techniques in exploring for, developing and exploiting natural gas and oil properties has helped us reduce drilling risks, lower finding costs and provide for more efficient production of natural gas and oil from our properties.

Oil and Natural Gas Activities

The following provides an overview of our major oil and natural gas projects during 2014. While actively pursuing specific exploration and development activities in each of the following areas, we continue to review other opportunities. There is no assurance that new drilling opportunities will be identified or that any new drilling opportunities will be successful if drilled. For additional information regarding our historical research and development expenditures, please see Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operation.”

Mid-Continent Horizontal Oil Play

The Hunton Limestone is a limestone formation stretching for over 2.7 million acres mainly in Oklahoma, but also in the neighboring states of Texas, New Mexico and Arkansas. Hunton Limestone economics are attractive due to the high quality oil production and the associated production of high Btu content natural gas in the area. As of December 31, 2014, we held leases covering approximately 225,800 gross (117,800 net) acres in Major, Garfield, Canadian, Kingfisher, Logan, Blaine and Oklahoma Counties, Oklahoma within the Hunton Limestone horizontal oil play. Our leasing activities in the initial AMI prospect area, primarily located in northwest Kingfisher County, Oklahoma, began in 2012 and have been expanded to include two additional adjacent prospect areas. In the initial

AMI, we currently pay 50% of lease acquisition costs for a 50% working interest. We pay 54.25% of the lease acquisition costs in the two additional prospect areas for a 50% working interest. In the initial prospect area, we are currently responsible for paying only the drilling and completion costs associated with our 50% working interest (our approximate net revenue interest is 39.0%). In all subsequent prospect areas, we pay 54.25% of gross drilling and completion costs to earn a 50% working interest. Our AMI partner handles all drilling, completion and production

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activities, and we handle leasing and permitting activities in certain areas of the AMI. For 2015, our focus is to drill in areas that we believe will result in the most significant proved reserve recognition to capital dollars spent and renew acreage in areas that our past drilling has proven to provide attractive returns and production rates and substantial reserve additions. We may elect to sell in the future any acreage that is determined to provide less attractive returns, productions and reserve additions or is outside of our drilling focus to reduce net capital expenditures.

On June 7, 2013, we acquired approximately 157,000 net acres of oil and natural gas leasehold interests in Canadian and Kingfisher Counties, Oklahoma from the Chesapeake Parties, including production interests in 206 gross producing wells for an adjusted cash purchase price of approximately $69.4 million. Effective July 1, 2013, our working interest partner in the original AMI in Oklahoma exercised its rights to acquire approximately 12,800 net acres and certain proved properties that we acquired from the Chesapeake Parties for a total payment of $11.6 million. In addition, on August 6, 2013, we sold approximately 76,000 net acres in Kingfisher and Canadian Counties, Oklahoma to Newfield Exploration Mid-Continent Inc. (“Newfield”) for an adjusted purchase price of approximately $57.0 million cash net of our purchase of approximately 1,850 net acres of Oklahoma oil and gas leasehold interests from Newfield for $1.5 million.

On November 15, 2013, we acquired a 98.3% working interest (80.5% net revenue interest) in 24,000 net acres of oil and natural gas leasehold interests in the West Edmond Hunton Lime Unit located in Kingfisher, Logan and Oklahoma Counties, Oklahoma, including production from interests in 56 gross (55.0 net) producing wells, for an adjusted cash purchase price of approximately $177.8 million.

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As of December 31, 2014 and currently as of the date of this report, we had production and drilling operations at various stages on the following non-operated wells in our original AMI in the Hunton Limestone formation:

Well Name	Current Working Interest	Approximate Lateral Length (in feet)	Peak Production Rates[1] (Boe/d)	Cumulative Production Averages[2] Boe/d	% Oil	Date of First Production or Status	Approximate Gross Costs to Drill & Complete ($ millions)
Jett 1-12H	47.4%	3,900	408	231	77%	February 1, 2014	$6.3
Jones 1-21H	48.4%	4,200	449	157	55%	March 2, 2014	$5.6
Liebhart 1-31H	48.8%	4,400	146	71	75%	March 18, 2014	$7.0
Coronado 1-3H	43.6%	4,300	224	127	71%	March 19, 2014	$5.3
Gamebird 1-7H	48.4%	4,400	764	482	76%	April 2, 2014	$5.5
Sieber 1-31H	33.7%	4,400	1,013	438	63%	April 13, 2014	$5.2
Kodiak 1-29H	45.3%	4,300	1,666	507	73%	May 4, 2014	$4.5
Anna Lee 1-30H	50.0%	4,400	220	128	73%	May 20, 2014	$5.1
Vaverka 1-20H	46.6%	4,400	315	170	67%	July 10, 2014	$5.7
Sasquatch 1-23H	44.2%	4,800	581	242	65%	July 27, 2014	$5.6
Jam 1-4H	33.1%	4,900	477	245	58%	August 8, 2014	$5.8
Yeti 1-29H	35.4%	5,000	1,015	334	61%	August 26, 2014	$5.3
Danny Ray 1-30H	40.3%	5,000	415	210	58%	August 29, 2014	$5.8
Cline 1-13H	54.3%	5,100	166	109	77%	September 6, 2014	$5.0
Michael J 1-18H	43.7%	5,000	740	458	66%	September 29, 2014	$5.2
Shimanek 1-2H	48.9%	5,000	1,829	887	64%	October 9, 2014	$6.0
Hobbs Ranch 1-19H	47.0%	4,400	875	556	77%	October 13, 2014	$5.2
Snowman 1-19H	48.9%	4,900	295	188	72%	October 19, 2014	$5.6
Breckenridge 1-2H	25.4%	4,800	207	143	76%	November 7, 2014	$5.0
Bear Claw 1-28H	50.0%	5,000	395	296	70%	November 13,2014	$6.2
Joyce 1-10H[3]	51.7%	5,300	904	519	74%	December 5, 2014	$6.9
Barry 1-6H	47.8%	5,000	427	307	85%	December 13, 2014	$6.0
LB 1-1H	50.0%	4,400	N/A	N/A	N/A	January 23, 2015	$5.0
Boss Hogg 1-14H	42.0%	4,400	N/A	68	60%	February 21, 2015	$7.2
Polar Bear 1-20H	47.6%	4,400	N/A	N/A	N/A	Awaiting completion	$5.0

Falcon 1-5H	51.5%	4,700	N/A	N/A	N/A	Awaiting completion	$5.0
The River 1-22H	28.3%	4,400	N/A	N/A	N/A	Awaiting completion	$5.0
Hubbard 1-23H(4)	57.0%	4,600	N/A	N/A	N/A	Awaiting completion	$5.0
Bigfoot 1-9H	43.0%	4,800	N/A	N/A	N/A	Awaiting completion	$5.0
Bo 1-23H	50.0%	4,900	N/A	N/A	N/A	Awaiting completion	$5.0
Dorothy 1-12H	31.0%	5,000	N/A	N/A	N/A	Awaiting completion	$5.0
Unruh 1-34H	50.0%	4,900	N/A	N/A	N/A	Awaiting completion	$5.0

(1) Represents highest daily gross Boe rate.
(2) Represents gross average production for actual producing days through February 28, 2015.
(3) After payout working interest is 45.0%.
(4) After payout working interest is 49.9%.

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In addition to the wells above, we also participated on a non-operated basis in wells outside of the AMI operated by our AMI partner. As of December 31, 2014 and currently as of the date of this report, we had production and drilling operations at various stages on the following non-operated wells outside of the initial AMI in the Hunton Limestone formation:

Well Name	Current Working Interest	Approximate Lateral Length (in feet)	Peak Production Rates(1) (BOE/d)	Cumulative Production Averages(2) BOE/d	Cumulative Production Averages(2) % Oil	Date of First Production or Status	Approximate Gross Costs to Drill & Complete ($ millions)
Rosemary 1-3H	15.6%	3,400	476	220	55%	February 22, 2014	$5.5
Grizzly 1-4H	8.8%	3,600	387	173	55%	May 1, 2014	$4.8
Niemyer 1-2H	17.7%	5,000	422	248	56%	June 24, 2014	$5.7
Wolf 1-9H	16.1%	3,600	391	279	62%	January 3, 2015	$5.5

(1) Represents highest daily gross Boe rate.

(2) Represents gross average production for actual producing days through February 28, 2015.

As of December 31, 2014 and currently as of the date of this report, we had production and drilling operations at various stages on the following operated wells on our acquired acreage in the Hunton Limestone formation:

Well Name	Current Working Interest	Approximate Lateral Length (in feet)	Peak Production Rates(1) (BOE/d)	Cumulative Production Averages(2) BOE/d	Cumulative Production Averages(2) % Oil	Date of First Production or Status	Approximate Gross Costs to Drill & Complete ($ millions)
Taborek 22-1H	87.4%	3,000	270	127	37%	March 6, 2014	$10.0
Easton 22-1H	98.3%	4,900	673	318	90%	July 30, 2014	$7.8
Easton 22-2H	98.3%	6,500	855	287	92%	August 5, 2014	$3.9
Horseshoe 3-1H	99.3%	5,100	380	185	35%	September 16, 2014	$7.0
Deer Draw 21-4H	98.3%	5,900	495	413	81%	November 7, 2014	$4.9
Deer Draw 21-5H	98.3%	4,900	344	234	85%	November 9, 2014	$5.0
Warsaw 33-2H	98.3%	4,900	N/A	481	80%	February 12, 2015	$3.5
Warsaw 33-3H	98.3%	5,800	648	277	71%	February 13, 2015	$5.9
Warsaw 33-1(3)	98.3%	N/A	N/A	N/A	N/A	Awaiting completion	$3.5

Easton 22-3H	98.3%	6,500	N/A	N/A	N/A	Drilling	$5.0
Blair Farms 31-1H	98.3%	6,500	N/A	N/A	N/A	Drilling	$3.2

(1) Represents highest daily gross Boe rate.

(2) Represents gross average production for actual producing dates through February 28, 2015.

(3) The Warsaw 33-1 is a vertical well.

We have also participated in four gross (0.2 net) wells outside of our AMI acreage targeting the Woodford Shale and the Mississippi Lime formations.

We continue to target our horizontal laterals in the lower Hunton Limestone formation and increase the number of fracs in the horizontal lateral as warranted by log analysis. We are continuing to monitor well flow back results on recently drilled and completed wells and remain encouraged by the high volumes of completion fluids being flowed back and higher oil production percentage.

At December 31, 2014, proved reserves attributable to the Mid-Continent were approximately 34.0 MMBoe, a 92% increase from year-end 2013 reserves. As of December 31, 2014, Mid-Continent proved reserves represented approximately 33% of our total proved reserves and 64% of our SEC total proved PV-10 value. Total Mid-Continent proved reserves at year-end 2014 were comprised of approximately 79% of oil and condensate and NGLs reserves. Approximately 33% of the Mid-Continent year-end 2014 reserves are proved developed.

The following table provides production and operational information about the Mid-Continent for the periods indicated:

	For the Years Ended December 31,		
Mid-Continent	2014	2013	2012
Production:			
Oil and condensate (MBbl)	792	189	2
Natural gas (MMcf)	2,822	1,095	1
NGLs (MBbl)	332	23	—
Total Production (MBoe)	1,594	395	2
Oil and condensate (MBbl/d)	2.2	0.5	—
Natural gas (MMcf/d)	7.7	3.0	—
NGLs (MBbl/d)	0.9	0.1	—
Total daily production (MBoe/d)	4.4	1.1	0.01
Average sales price per unit(1):			
Oil and condensate (per Bbl)	$88.84	$94.80	$85.22
Natural gas (per Mcf)	$4.24	$4.75	$3.47
NGLs (per Bbl)	$31.79	$33.06	$36.15
Average sales price per Boe(1)	$58.27	$60.53	$75.58
Selected operating expenses (in thousands):			
Production taxes	$2,940	$820	$2
Lease operating expenses	$15,112	$4,019	$33
Transportation, treating and gathering	$40	$3	$—
Selected operating expenses per Boe:			
Production taxes	$1.84	$2.08	$1.22
Lease operating expenses	$9.48	$10.17	$18.79
Transportation, treating and gathering	$0.02	$0.01	$—
Production costs(2)	$9.50	$10.17	$18.79

(1) Excludes the impact of hedging activities.

(2) Production costs include lease operating expense, insurance, transportation, treating and gathering and workover expense and excludes ad valorem and severance taxes.

For the year ended December 31, 2014, net production from the Mid-Continent averaged 4.4 MBoe/d compared to 1.1 MBoe/d for the year ended December 31, 2013. For the three months ended December 31, 2014, net production from the Mid-Continent averaged 5.6 MBoe/d compared to 4.5 MBoe/d for the three months ended September 30, 2014 and 2.3 MBoe/d for the three months ended December 31, 2013.

Our 2015 Mid-Continent capital budget includes plans to spud a total of 14 gross (12.2 net) wells, comprised of three gross (1.4 net) non-operated wells primarily located within our current AMI and 11 gross (10.8 net) operated wells in the WEHLU. We anticipate completing a total of 21 gross (16.2 net) wells in the Hunton Limestone during 2015, comprised of eight gross (3.4 net) non-operated wells primarily located within our current AMI and 13 gross (12.8 net) operated WEHLU wells.

Appalachian Basin

Marcellus Shale

The Marcellus Shale is Devonian aged shale that underlies much of the Appalachian region of Pennsylvania, New York, Ohio, West Virginia and adjacent states. The depth of the Marcellus Shale and its low permeability make the Marcellus Shale an unconventional exploration target in the Appalachian Basin. Advancements in horizontal drilling and hydraulic fracture stimulation have produced promising results in the Marcellus Shale. These developments have resulted in increased leasing and drilling activity in the area. As of December 31, 2014, our acreage position in the play was approximately 74,100 gross (51,300 net) acres. We refer to the approximately 32,100 gross (13,500 net) acres reflecting our interest in our Marcellus Shale assets in West Virginia and Pennsylvania subject to our joint venture (the “Atinum Joint Venture”) with an affiliate of Atinum Partners

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Co. Ltd. ("Atinum") as our "Marcellus West acreage." We refer to the approximately 42,100 gross (37,800 net) acres in Preston, Tucker, Pocahontas, Randolph and Pendleton Counties, West Virginia as our "Marcellus East acreage." The entirety of our acreage is believed to be in the core, over-pressured area of the Marcellus Shale play. We continue to opportunistically swap acreage with adjacent operators to optimize our acreage and maximize horizontal lateral lengths.

On September 21, 2010, we entered into the Atinum Joint Venture pursuant to which we ultimately assigned to Atinum, for $70.0 million in total consideration, a 50% working interest in certain undeveloped acreage and shallow producing wells. Atinum has the right to participate in any future leasehold acquisitions made by us within Ohio, New York, Pennsylvania and West Virginia, excluding the counties of Pendleton, Pocahontas, Preston, Randolph and Tucker, West Virginia, on terms identical to those governing the existing Atinum Joint Venture. We are the operator and are obligated to offer any future lease acquisitions to Atinum on a 50/50 basis. Atinum will pay us on an annual basis an amount equal to 10% of lease bonuses and third party leasing costs, up to $20.0 million, and 5% of such costs on activities above $20.0 million.

The Atinum Joint Venture pursued an initial three-year development program that called for the partners to drill a minimum of 60 operated horizontal wells by year-end 2013. Due to natural gas price declines, we and Atinum agreed to reduce the minimum wells to be drilled requirements from 60 gross wells to 51 gross wells. At December 31, 2014, 67 gross (32.0 net) operated Marcellus Shale horizontal wells were capable of production. All of our Marcellus Shale well operations to date were drilled under the Atinum Joint Venture. The Atinum Joint Venture agreement expires on November 1, 2015.

As of December 31, 2014, and currently as of the date of this report, we had drilling operations at various stages on the following Marcellus Shale wells in Marshall County, West Virginia:

Pad	Gross Well Count	Net Well Count	Working Interest	Estimated Net Revenue Interest	Average Lateral Length (in feet) (1)	Status	Estimated Production Date
Goudy(2)	3.0	1.5	50.0%	40.0%	6,100	Awaiting completion	March 2015
Hoyt(3)	2.0	1.0	50.0%	42.7%	5,000	Awaiting completion	April 2015
Blake(4)	2.0	1.0	50.0%	41.9%	5,700	Awaiting completion	May 2015
	7.0	3.5					

(1) Average well lateral length approximates the actual average well lateral length for wells that have been completed and the estimated average well lateral length for wells that have not been completed.

(2) The Goudy pad is projected to ultimately have nine gross wells, four of which were initially placed on production in August 2013 and three of which are awaiting completion.

(3) The Hoyt pad is projected to ultimately have seven gross wells.

(4) The Blake pad is projected to ultimately have nine gross wells.

As of December 31, 2014, we had an interest in seven gross (1.3 net) non-operated horizontal Marcellus Shale wells in Butler County, Pennsylvania and an additional four gross (0.9 net) non-operated horizontal Marcellus Shale wells in Marshall County, West Virginia. Currently, we have no plans to participate in any additional Marcellus Shale non-operated wells in 2015.

From the inception of our operations in the Marcellus Shale in 2011 to late 2013, our operated production and sales in West Virginia were temporarily curtailed by issues with condensate handling, dehydration limitations, high line pressures and excessive unscheduled system down-time on a third-party-operated gathering system. The gathering system operator continually attempted to resolve these issues with operational improvements. Subsequent to October 1, 2013, we have not experienced significant curtailment or high line pressure issues on our Marcellus West production on the third-party gathering system. In July 2013, we initiated an arbitration proceeding requesting damages against the gathering system operator for, among other claims, failure to timely construct certain gathering

and processing facilities, maximize the net value of produced condensation, and fractionate and purchase NGLs, which claims were settled in June 2014.
At December 31, 2014, proved reserves attributable to the Marcellus Shale were approximately 61.0 MMBoe, a 65% increase from year-end 2013 reserves of 36.9 MMBoe, which represented approximately 60% of our total proved reserves and 34% of PV-10 value. Total Marcellus Shale proved reserves at year-end 2014 were comprised of approximately 45% of oil and condensate and NGLs reserves compared to 34% at year-end 2013. Approximately 41% of the Marcellus Shale year-end 2014 reserves are proved developed compared to 58% at December 31, 2013.

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The following table provides production and operational information for the Marcellus Shale for the periods indicated:

	For the Years Ended December 31,		
Marcellus Shale	2014	2013	2012
Production:			
Oil and condensate (MBbl)	182	315	160
Natural gas (MMcf)	8,050	9,594	5,477
NGLs (MBbl)	469	471	270
Total production (MBoe)	1,993	2,385	1,343
Oil and condensate (MBbl/d)	0.5	0.9	0.4
Natural gas (MMcf/d)	22.1	26.3	15.0
NGLs (MBbl/d)	1.3	1.3	0.7
Total daily production (MBoe/d)	5.5	6.5	3.7
Average sales price per unit(1)(2):			
Oil and condensate (per Bbl)	$68.21	$55.61	$62.40
Natural gas (per Mcf)	$4.28	$2.86	$2.33
NGLs (per Bbl)	$23.11	$31.52	$28.22
Average sales price per Boe(1)(2)	$28.97	$25.08	$22.62
Selected operating expenses (in thousands):			
Production taxes(3)	$3,685	$3,805	$2,138
Lease operating expenses(3)	$4,187	$3,181	$2,070
Transportation, treating and gathering(3)	$3,552	$1,176	$1,090
Selected operating expenses per Boe:			
Production taxes(3)	$1.85	$1.60	$1.59
Lease operating expenses(3)	$2.10	$1.33	$1.54
Transportation, treating and gathering(3)	$1.78	$0.49	$0.81
Production costs(4)	$3.50	$1.76	$2.29

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(1) Excludes the impact of hedging activities.

(2) The year ended December 31, 2014 includes the benefit of a non-recurring revenue adjustment related to an arbitration settlement. Excluding the arbitration settlement adjustment impact, average sales prices would have been as follows:

	For the Year Ended December 31, 2014
Marcellus Shale	
Average sales price per unit:	
Oil and condensate (per Bbl)	$50.96
Natural gas (per Mcf)	$3.27
NGLs (per Bbl)	$24.55
Average sales price per Boe	$23.65

(3) The year ended December 31, 2014 includes a non-recurring adjustment to production taxes, lease operating expenses and transportation, treating and gathering related to an arbitration settlement. Excluding the arbitration settlement adjustment impact, production taxes, lease operating expenses and transportation, treating and gathering per Boe would have been as follows:

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	For the Year Ended December 31, 2014
Marcellus Shale	
Selected operating expenses per Boe:	
Production taxes	$ 1.56
Lease operating expenses	$ 2.19
Transportation, treating and gathering	$ 0.99

(4) Production costs include lease operating expense, insurance, transportation, treating and gathering and workover expense and excludes ad valorem and severance taxes. Excluding the arbitration settlement adjustment impact, production costs for the year ended December 31, 2014 would have been as follows:

	For the Year Ended December 31, 2014
Marcellus Shale	
Selected operating expenses per Boe:	
Production costs	$ 2.80

Our 2015 capital budget includes plans to complete seven gross (3.5 net) wells in the Marcellus Shale. We will continue to monitor prices and services costs, and should well costs decline significantly or higher net realized area product pricing improve, we may elect to resume drilling operations in the area.

Utica Shale

The Utica Shale is Ordovician aged shale that underlies much of the Appalachian region of Pennsylvania, Ohio and West Virginia. The depth of the Utica Shale and its low permeability make the Utica Shale an unconventional exploration target in the Appalachian Basin. Advancements in horizontal drilling and hydraulic fracture stimulation have produced promising results in the Utica Shale, some in close proximity to our existing Marcellus West acreage. Based on log analysis of offsetting wells, recent Utica Shale completions by other nearby operators and the drilling and completion of our first horizontal Utica Shale well, we believe that our Marcellus West acreage should be prospective for high-pressure, high-deliverability dry natural gas development in the Utica Shale. We spudded our first Utica Shale well, the Simms U-5H, on April 3, 2014. We drilled the Simms U-5H to a total vertical depth of 11,500 feet and drilled an approximate 4,400-foot lateral and completed it with a 25-stage fracture stimulation. The Simms U-5H was producing at a last five-day average rate of 9.1 MMcf/d of natural gas and had total cumulative production of 2.1 Bcf as of February 28, 2015. Our working interest in the Simms U-5H is 50.0% (43.2% net revenue interest). We spudded our second Utica Shale well, the Blake U-7H, in late November 2014, in which we own a 50% working interest (41.1% net revenue interest). Currently, we are projecting flow back operations will commence in May 2015. At December 31, 2014, one gross (0.5 net) operated Utica Shale horizontal well was capable of production and one gross (0.5 net) operated Utica Shale well was awaiting completion. All of our Utica Shale well operations to date were drilled under the Atinum Joint Venture. The Atinum Joint Venture agreement expires on November 1, 2015. For the year ended December 31, 2014, net production from the Utica Shale averaged 0.3 MBoe/d. For the three months ended December 31, 2014, net production from the Utica Shale averaged 1.0 MBoe/d compared to 0.3 MBoe/d for the three months ended September 30, 2014.

At December 31, 2014, proved reserves attributable to the Utica Shale were approximately 7.1 MMBoe, or 7% of our total proved reserves, and were comprised 100% of natural gas reserves. Approximately 12% of the Utica Shale year-end 2014 reserves are proved developed.

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The following table provides production and operational information for the Utica Shale for the period indicated:

Utica Shale	For the Year Ended December 31, 2014
Production:	
Natural gas (MMcf)	725
Total production (MBoe)	121
Natural gas (MMcf/d)	2.0
Total daily production (MBoe/d)	0.3
Average sales price per unit(1):	
Natural gas (per Mcf)	$ 1.68
Average sales price per Boe(1)	$ 10.10
Selected operating expenses (in thousands):	
Production taxes	$ 109
Lease operating expenses	$ 24
Transportation, treating and gathering	$ 87
Selected operating expenses per Boe:	
Production taxes	$ 0.90
Lease operating expenses	$ 0.20
Transportation, treating and gathering	$ 0.72
Production costs(2)	$ 0.92

(1) Excludes the impact of hedging activities.

(2) Production costs include lease operating expense, insurance, gathering and workover expense and excludes ad valorem and severance taxes.

Our 2015 capital budget includes plans to complete one gross (0.5 net) well previously drilled in the Utica Shale. We will continue to monitor prices and services costs, and should well costs decline significantly or net realized area product pricing improves, we may elect to resume drilling operations in the area.

Hilltop Area, East Texas

In October 2013, we sold substantially all of our leasehold interests in the Hilltop Area of East Texas, consisting of 31,800 gross (16,300 net) acres and 37 producing wells to Cubic Energy, Inc. for adjusted net proceeds of approximately $42.9 million.

Powder River Basin, Wyoming and Montana

On May 3, 2012, we assigned our working interest in the Powder River Basin to the operator effective January 1, 2012.

Markets and Customers

The success of our operations is dependent primarily upon prevailing and future prices for oil, condensate, natural gas and NGLs. The markets for oil, condensate, natural gas and NGLs have historically been and currently continue to be volatile. Oil, condensate, natural gas and NGLs prices are beyond our control.

We contract to sell natural gas from our properties with spot market contracts that vary with market forces on a daily basis. While overall natural gas prices at major markets, such as Henry Hub in Erath, Louisiana, may have some impact on regional prices, the regional natural gas price at our production facilities may move somewhat independently of broad industry price trends. We are directly impacted by natural gas prices in the regions in which we operate regardless of pricing at major market hubs. We do not own or operate any natural gas lines or distribution facilities and rely on third parties to construct additional interstate pipelines to increase our ability to bring our production to market. Any significant change affecting these facilities or our failure to obtain timely access to existing or future facilities on acceptable terms could restrict our ability to conduct normal operations. Delays in the commencement of operations of new pipelines, the unavailability of new pipelines or

other facilities due to market conditions, mechanical reasons or otherwise could have an adverse impact on our results of operations and financial condition.

There are limited natural gas purchaser and transporter alternatives currently available near our Marcellus and Utica Shale acreage in the Appalachian Basin. Our Appalachian Basin production is sold on the spot market to regional pipeline companies. There are numerous natural gas purchasers and transport and processing options in the area of our Mid-Continent horizontal oil play, and all natural gas production from this region is sold on the spot market to regional pipeline companies. Prior to the October 2013 sale of substantially all of our interest in East Texas, ETC Texas Pipeline, Ltd. ("ETC") provided for the treating, purchase and transportation of substantially all of our natural gas production from this area. Our deep Bossier production was transported to the Katy Hub in Katy, Texas, where numerous parties were available to purchase our natural gas production. Prior to the assignment of our interest in the Powder River Basin to the operator, our Powder River Basin natural gas was sold under spot market contracts to major pipeline and natural gas marketing companies.

Our oil, condensate and NGLs production in the Appalachian Basin and the Mid-Continent is sold under spot sales transactions at market prices. Prior to the October 2013 sale of our East Texas interests, our oil and condensate production in this region was sold under spot sales transactions at market prices. The availability and price responsiveness of the multiple oil and condensate purchasers provides for a highly competitive and liquid market for oil sales.

During December 2010, we, along with Atinum, entered into a gas purchase agreement with SEI Energy, LLC ("SEI") with respect to our Marcellus West Marshall County, West Virginia production. The initial term of the gas purchase agreement is five years with the option to extend the term of the gas purchase agreement for an additional five-year period. Our Marshall County, West Virginia production is dedicated to SEI for the term of the gas purchase agreement. During December 2014, the gas purchase agreement with SEI was amended to include all of our Wetzel County, West Virginia production in addition to the previously dedicated Marshall County, West Virginia production. SEI will purchase all hydrocarbon production, including all natural gas, condensate and natural gas liquids. SEI has an agreement to utilize the Williams Ohio Valley Midstream LLC ("Williams") midstream facilities (formerly owned by Caiman Energy Midstream, LLC), including its 520.0 MMcf/d Fort Beeler processing plant located in Marshall County, West Virginia for transporting and processing. In order to secure access to the Williams facilities, we, Atinum and SEI dedicated all hydrocarbons purchased and produced in Marshall County, West Virginia for a term of ten years. From the inception of our operations in the Marcellus Shale in 2011 to late 2013, our operated production and sales in West Virginia were temporarily curtailed by issues with condensate handling, dehydration limitations, high line pressures and excessive unscheduled system down-time on a third-party-operated gathering system. The gathering system operator continually took steps to attempt to resolve these issues with operational improvements. In July 2013, we initiated an arbitration proceeding requesting damages against the gathering system operator for, among other claims, failure to timely construct certain gathering and processing facilities, maximize the net value of produced condensation, and fractionate and purchase NGLs as provided in the agreements, which claims were settled in June 2014. In conjunction with the settlement, the SEI and Williams contracts were amended regarding certain fees and operational matters and the contracts were extended through July 1, 2023.

On November 16, 2009, concurrent with the sale of our Hilltop gathering system in East Texas, our wholly-owned subsidiary entered into a gas gathering agreement effective November 1, 2009 with Hilltop Resort GS, LLC (the "Hilltop Gathering Agreement") for a term of 15 years. As a condition to the sale of our East Texas interests, Cubic Energy, Inc., the purchaser of our East Texas properties, assumed all obligations pursuant to the Hilltop Gathering Agreement.

In March 2008, we entered into formal agreements with ETC for the treating, purchase and transportation of substantially all of our natural gas production from the Hilltop area of East Texas (the "ETC Contract"). The ETC Contract was effective as of September 1, 2007 and had a term of 10 years. As a condition to the sale of our East Texas interests, Cubic Energy, Inc. assumed the ETC Contract.

The following table provides information regarding our significant customers and the percentages of oil, condensate, natural gas and NGLs revenues, excluding hedge impact, which they represented for the periods indicated:

	For the Years Ended December 31,					
	2014		2013		2012	
SEI	50	%	56	%	47	%
Sunoco	37	%	16	%	—	%
Clearfield Appalachian	—	%	8	%	14	%
ETC	—	%	8	%	24	%

SEI and Clearfield Appalachian purchase the majority of our Marcellus Shale production. There are limited oil, condensate, natural gas and NGLs purchase and transportation alternatives currently available in the Appalachian Basin. If SEI or Clearfield Appalachian were to cease purchasing and transporting our oil, condensate, natural gas and NGLs production and we were unable to obtain timely access to existing or future facilities on acceptable terms, or in the event of any significant change affecting these facilities, including delays in the commencement of operations of any new pipelines or the unavailability of the new pipelines or other facilities due to market conditions, mechanical reasons or otherwise, our ability to conduct normal operations would be significantly restricted. SEI and Sunoco purchase the majority of our Mid-Continent production. There are numerous purchase and transportation alternatives currently available in the Mid-Continent so in the event that SEI or Sunoco were to cease purchasing and transporting our oil, condensate, natural gas and NGLS production, our ability to conduct normal operations would not be significantly restricted. Prior to the sale of our East Texas interests, ETC treated, transported and purchased substantially all of our East Texas natural gas production. For more information, see Item 1A. “Risk Factors-Our ability to market our oil, condensate, natural gas and NGLs may be impaired by capacity constraints and availability of the gathering systems and pipelines that transport our oil, condensate, natural gas and NGLs.”

Competition

The oil and natural gas industry is intensely competitive in all of its phases. We encounter competition from other oil and natural gas companies in all areas of our operations. In seeking suitable oil and natural gas properties for acquisition, we compete with other companies operating in our areas of interest, including large oil and natural gas companies and other independent operators, many of whom have greater financial resources and, in many instances, have been engaged in the exploration and production business for a much longer time than we have. Many of our competitors also have substantially larger operating staffs than we do. Many of these competitors not only explore for and produce oil and natural gas but also market oil and natural gas and other products on a regional, national or worldwide basis. These competitors may be able to pay more for productive oil and natural gas properties and exploratory prospects and define, evaluate, bid for and purchase a greater number of properties and prospects than us. In addition, these competitors may have a greater ability to continue exploration activities during periods of low market prices. Our ability to acquire additional properties and to discover reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. For more information, see Item 1A. “Risk Factors-Competition in the oil and natural gas industry is intense. We are smaller and have less operating history than many of our competitors, and increased competitive pressure could adversely affect our results of operations.”

Prices of our oil, condensate, natural gas and NGLs production are controlled by market forces. Competition in the oil and natural gas exploration industry, however, also exists in the form of competition to acquire leases and obtain favorable transportation prices. We are smaller and have a more limited operating history than most of our competitors and may have difficulty acquiring additional acreage and/or projects and arranging for the transportation of our production. We also face competition in obtaining oil and natural gas drilling rigs and in providing the manpower to operate them and provide related services.

Seasonal Nature of Business

Generally, the demand for natural gas is dependent upon weather with prices decreasing during the summer months and increasing during the winter months. Seasonal anomalies such as mild winters or abnormally hot summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. Seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other oil and natural gas operations in certain areas. These seasonal anomalies can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages, increase our costs or delay our operations.

U.S. Governmental Regulation

Our oil and natural gas exploration, production and related operations are subject to extensive rules and regulations promulgated in the United States. These laws and regulations, all of which are subject to change from time to time, include matters relating to land tenure; drilling and production practices, such as discharge permits and the spacing of wells; the disposal of water resulting from operations and the processing, handling and disposal of hazardous materials, such as hydrocarbons and naturally occurring radioactive materials; bonding requirements; ongoing obligations for licensing; reporting requirements; marketing and pricing policies; royalties; taxation; and foreign trade and investment.

Failure to comply with governmental rules and regulations can result in substantial penalties. Furthermore, we could be liable for personal injuries, property damage, spills, discharge of hazardous materials, reclamation costs, remediation, clean-up costs and other environmental damages as a consequence of acquiring a natural gas or oil prospect or acreage.

The regulatory burden on the oil and natural gas industry increases our cost of doing business and affects our financial condition. Although we believe we are in substantial compliance with all applicable laws and regulations, we are unable to

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predict the future cost or impact of complying with such laws because those laws and regulations are frequently amended or reinterpreted. We are unable to predict what additional legislation or amendments may be proposed that will affect our operations or when any such proposals, if enacted, might become effective. We do not expect that any of these laws would affect us in a materially different manner than any other similarly sized oil and natural gas company operating in the United States.

Regulation of Exploration and Production

Regulation of Production

The production of natural gas and oil is subject to extensive regulation under a wide range of federal, state and local statutes, rules, orders and regulations. Federal, state and local statutes and regulations require, among other things, permits for drilling operations, drilling bonds and reports concerning operations. The states in which we own and operate properties have regulations governing conservation matters, including some provisions for the unitization or pooling of the natural gas and oil properties; the establishment of maximum rates of production from natural gas and oil wells; the spacing of wells; and the plugging and abandonment of wells and removal of related production equipment. These and other regulations can limit the amount of the natural gas and oil we can produce from our wells, limit the number of wells we can drill or limit the locations at which we can conduct drilling operations. Moreover, each state generally imposes a production or severance tax with respect to production and sale of natural gas, condensate, NGLs and crude oil within its jurisdiction.

Regulation of Sales of Natural Gas

The price at which we buy and sell natural gas is currently not subject to federal rate regulation and, for the most part, is not subject to state regulation. However, with regard to our physical purchases and sales of these energy commodities, and any related hedging activities that we undertake, we are required to observe anti-market manipulation laws and related regulations enforced by the Federal Energy Regulatory Commission (“FERC”) and/or the Commodity Futures Trading Commission (“CFTC”). See the discussion below of “Other Federal Laws and Regulations Affecting Our Industry – Energy Policy Act of 2005”. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities. In addition, pursuant to Order 704 (defined below), we may be required to annually report to FERC on May 1 of each year information regarding natural gas purchase and sale transactions depending on the volume of natural gas transacted during the prior calendar year. See the discussion below of “Other Federal Laws and Regulations Affecting Our Industry – FERC Market Transparency Rules.”

Regulation of Availability, Terms and Cost of Pipeline Transportation

The availability, terms and cost of transportation can significantly affect sales of natural gas. FERC regulates interstate natural gas pipeline transportation rates and service conditions, which affect the marketing of natural gas produced by us and the revenues received by us for sales of such natural gas. FERC requires interstate pipelines to offer available firm transportation capacity on an open access, non-discriminatory basis to all natural gas shippers. FERC frequently reviews and modifies its regulations regarding the transportation of natural gas with the stated goal of fostering competition within all phases of the natural gas industry. In addition, with respect to production onshore or in state waters, the intra-state transportation of natural gas would be subject to state regulatory jurisdiction as well. The ability of our facilities to deliver natural gas into third party natural gas pipeline facilities is directly impacted by the gas quality specifications required by those pipelines. In 2006, FERC issued a policy statement on provisions governing gas quality and interchangeability in the tariffs of interstate gas pipeline companies and a separate order declining to set generic prescriptive national standards. FERC strongly encouraged all natural gas pipelines subject to its jurisdiction to adopt, as needed, gas quality and interchangeability standards in their FERC gas tariffs modeled on the interim guidelines issued by a group of industry representatives headed by the Natural Gas Council (the “NGC+ Work Group”), or to explain how and why their tariff provisions differ. We have no way to predict, however, whether FERC will approve of gas quality specifications that materially differ from the NGC+ Work Group’s interim guidelines for such an interconnecting pipeline.

State laws and regulations generally govern the gathering and intrastate transportation of natural gas. Natural gas gathering systems in the states in which we operate are generally required to offer services on a non-discriminatory basis, and are subject to state ratable take and common purchaser statutes. Ratable take statutes generally require gatherers to take, without undue discrimination, natural gas production that may be tendered to the gatherer for handling. Similarly, common purchaser statutes generally require gatherers to purchase without discrimination in favor of one producer over another producer or one source of supply over another source of supply.

Other Federal Laws and Regulations Affecting Our Industry

Energy Policy Act of 2005. Under the Energy Policy Act of 2005 (the "EPAct 2005"), Congress made it unlawful for any entity, including otherwise non-jurisdictional producers of natural gas, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services regulated by the FERC that violates the FERC's rules. FERC's rules implementing the provision of EPAct 2005 make it unlawful for any entity in connection with the purchase or sale of natural gas subject to the jurisdiction of FERC, or the purchase or sale of transportation services subject to the jurisdiction of FERC, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the Natural Gas Act and the Natural Gas Policy Act up to $1,000,000 per day per violation. While EPAct 2005 reflects a significant expansion of the FERC's enforcement authority, we do not anticipate that we will be affected by that statute any differently than other producers of natural gas.

FERC Market Transparency Rules. In 2007, FERC issued a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing ("Order 704"). Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtu of physical natural gas in the previous calendar year including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors and natural gas marketers are now required to report on Form No. 552 on May 1 of each year aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, FERC and the courts. We cannot predict the ultimate impact of these or the above regulatory changes to our natural gas operations. We do not believe that we would be affected by any such FERC action materially differently than other natural gas companies with whom we compete.

Additional proposals and proceedings that might affect the natural gas industry are considered from time to time by Congress, FERC, state regulatory bodies and the courts. We cannot predict when or if any such proposals might become effective or their effect, if any, on our operations. The natural gas industry historically has been closely regulated; thus, there is no assurance that the less stringent regulatory approach recently pursued by FERC and Congress will continue indefinitely into the future. We do not believe that we will be affected by any action taken in a materially different way than other natural gas producers, gatherers and marketers with which we compete.

Federal Regulation of Sales and Transportation of Crude Oil. The oil industry is also extensively regulated by numerous federal, state and local authorities. Prices for crude oil and condensate are not currently regulated and are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

In a number of instances, however, the ability to transport and sell such products on interstate pipelines is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act ("ICA"). The ICA requires that pipelines maintain a tariff on file with FERC. The tariff sets forth the established rate as well as the rules and regulations governing the service. The ICA requires, among other things, that rates on interstate common carrier pipelines be "just and reasonable." The ICA permits challenges to existing rates and authorizes FERC to investigate such rates to determine whether they are just and reasonable. If, upon completion of an investigation, FERC finds that the existing rate is unlawful, it is authorized to require the carrier to refund the revenues in excess of the prior tariff collected during the pendency of the investigation and, in some cases, reparations for the two (2) year period prior to the filing of a complaint. We do not believe, however, that these regulations affect us any differently than other producers.

Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors who are similarly situated.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all similarly situated shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by pro-rationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our similarly situated competitors.

Our operations are subject to extensive and continually changing regulation affecting the natural gas and oil industry. Many departments and agencies, both federal and state are authorized by statute to issue, and have issued, rules and regulations binding on the natural gas and oil industry and its individual participants. The failure to comply with such rules and regulations can result in substantial penalties. The regulatory burden on the natural gas and oil industry increases our cost of doing business and, consequently, affects our profitability. We do not believe that we are affected in a significantly different manner by these regulations than are our competitors.

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U.S. Environmental and Occupational Safety and Health Regulation

Our oil and natural gas exploration, development and production operations, and similar operations that we do not operate but in which we own a working interest, are subject to stringent federal, regional, state and local environmental laws and regulations governing worker safety and health, environmental protection and the discharge of substances into the environment. Numerous governmental agencies, including the U.S. Environmental Protection Agency ("EPA"), the U.S. Occupational Safety and Health Administration and analogous state agencies have the power to enforce compliance with these laws and regulations and the permits issued under them, often requiring difficult and costly actions. These laws and regulations may require that permits, including drilling permits, be obtained before conducting regulated activities; restrict the types, quantities and concentrations of various substances that can be released into the environment as a result of natural gas and oil drilling, production and processing activities; suspend, limit or prohibit construction, drilling and other activities in certain lands lying within wilderness, wetlands and other protected areas; restrict injection of produced water or other regulated fluids into subsurface strata that may contaminate groundwater; require remedial measures to mitigate pollution from historical and on-going operations such as the use of pits and plugging of abandoned wells; impose specific safety and health criteria addressing workforce protection; and impose liabilities for pollution resulting from our operations. Failure to comply with these environmental and worker health and safety laws and regulations may result in the assessment of administrative, civil and criminal penalties, the imposition of remedial obligations or the issuance of injunctions limiting or prohibiting operations.

We believe that we are in substantial compliance with existing applicable environmental laws and regulations. However, it is possible that new environmental laws and regulations or the modification or more stringent enforcement of existing laws and regulations could have a material adverse effect on our operations and other operations in which we own an interest. The trend in environmental legislation and regulation is toward stricter standards to place more restrictions and limitations on activities that may affect the environment. To date, we have not been required to expend significant capital expenditures or other resources in order to satisfy existing applicable environmental laws and regulations, but there is no assurance that costs to comply with existing and any new environmental laws and regulations in the future will not be material. If substantial liabilities to third parties or governmental entities are incurred, the payment of such claims may reduce or eliminate the funds available for project investment or result in loss of our properties. Moreover, a serious incident of pollution may result in significant remedial costs and damages to natural resources or properties as well as the suspension or cessation of operations in the affected area. Although we maintain insurance coverage against costs of certain clean-up operations, no assurance can be given that we are fully insured against all such potential risks. The imposition of any of these liabilities or compliance obligations on us may have a material adverse effect on our financial condition and results of operations.

The following is a summary of some of the more significant existing environmental laws to which our business operations are subject.

Hazardous Substances and Wastes

The Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA"), also known as the Superfund law and analogous state laws impose strict, joint and several liability without regard to fault or legality of conduct on persons who are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the owner or operator of the site where the release occurred and companies that transported, disposed or arranged for the disposal of the hazardous substance released at the site. Under CERCLA, these "responsible parties" may be liable for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the responsible classes of persons the costs they incur. It is not uncommon for neighboring land owners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. Although CERCLA currently excludes, among other things, petroleum, natural gas and natural gas liquids from the definition of hazardous substance, our operations as well as other operations in which we own an interest generate materials that are subject to regulation as hazardous substances under CERCLA.

The Resource Conservation and Recovery Act, as amended (“RCRA”), and comparable state laws regulate the generation, treatment, storage, transportation and disposal of hazardous and non-hazardous wastes. Our operations, and other operations in which we own an interest, generate wastes, including hazardous wastes that are subject to RCRA and comparable state laws. Although RCRA currently exempts certain oil and natural gas exploration, development and production wastes from the definition of hazardous waste, allowing us to manage these wastes under RCRA's less stringent non-hazardous waste requirements, we cannot assure that this exemption will be preserved in the future. Repeal or modification of this exception or similar exemptions in state law could increase the amount of hazardous waste we are required to manage and dispose of and could cause us to incur increased operating costs, which could have a significant impact on us as well as the oil and natural gas industry in general.

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We currently own, lease, own a working interest in, or operate numerous properties that for many years have been used by third parties for the exploration, development and production of natural gas and oil. Although we utilized operating and disposal practices that were standard in the industry at the time, hazardous substances, wastes or petroleum hydrocarbons may have been released on or under the properties owned, leased or operated by us or in which we own an interest, or on or under other locations, including off-site locations, where such substances have been taken for disposal or recycling. In addition, many of these properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes, or petroleum hydrocarbons was not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes (including substances disposed of or released by prior owners or operators), remediate contaminated property (including groundwater contamination) or perform remedial plugging or pit closure operations to prevent future contamination.

Water Discharges and Subsurface Injections

Our operations and other operations in which we own a working interest are subject to the Federal Water Pollution Control Act, also known as the Clean Water Act, as amended (“CWA”), and analogous state laws. These laws and their implementing regulations impose detailed requirements and strict controls regarding the discharge of pollutants, including oil and hazardous substances, into waters of the United States and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Spill prevention, control and countermeasure (“SPCC”) plan requirements imposed under the CWA require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. The CWA also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. Depending on our area of operation, regional, state or local regulatory authorities typically govern the withdrawal of water for use in our operations. Federal and state regulatory agencies can impose administrative, civil and criminal penalties, as well as require remedial or mitigation measures, for noncompliance with discharge permits or other requirements of the CWA and analogous state laws and regulations.

The Oil Pollution Act of 1990, as amended (“OPA”), amends the CWA and sets minimum standards for prevention, containment and cleanup of oil spills. The OPA applies to vessels, offshore facilities, and onshore facilities, including exploration and production facilities that may affect waters of the United States. Under OPA, responsible parties including owners and operators of onshore facilities may be held strictly liable for oil cleanup costs and natural resource damages as well as a variety of public and private damages that may result from oil spills. The OPA also requires owners or operators of certain onshore facilities to prepare Facility Response Plans for responding to a worst-case discharge of oil into waters of the United States.

Our oil and natural gas exploration, development and production operations, and other operations in which we own an interest, generate produced water, drilling muds and other waste streams, some of which may be disposed by injection in underground wells situated in non-producing subsurface formations. The drilling and operation of these injection wells are regulated by the Safe Drinking Water Act, as amended (“SDWA”), and analogous state laws. The Underground Injection Well Program under the SDWA requires that we obtain permits from the EPA or analogous state agencies for our disposal wells, establishes minimum standards for injection well operations, restricts the types and quantities of fluids that may be injected, and prohibits the migration of fluids containing any contaminants into underground sources of drinking water. Any leakage from the subsurface portions of the injection wells may cause degradation of freshwater, potentially resulting in cancellation of operations of a well, imposition of fines and penalties from governmental agencies, incurrence of expenditures for remediation of affected resources, and imposition of liability by landowners or other parties claiming damages for alternative water supplies, property damages and personal injuries. While we believe that we have obtained the necessary permits from the applicable regulatory agencies for our underground injection wells and that we are in substantial compliance with permit conditions and federal and state rules, any changes in the laws or regulations or the inability to obtain permits for new

injection wells in the future may affect our ability to dispose of produced waters and would ultimately increase the cost of our operations, which costs could be significant.
Furthermore, in response to recent seismic events near underground disposal wells used for the disposal by injection of produced water resulting from oil and natural gas activities, federal and some state agencies are investigating whether such wells have caused increased seismic activity, and some states have shut down or imposed moratoria on the use of such disposal wells. For example, in Oklahoma, the governor announced in September 2014 the creation of a Coordinating Council on Seismic Activity, the purpose of which is to help researchers, policymakers, regulators and oil and natural gas industry study seismicity in the state, and the Utility and Environment Committee of the Oklahoma House of Representatives also has considered what, if any, correlations exist between disposal wells and seismic activity in the state. Moreover, in September 2014, the Oklahoma Corporation Commission ("OCC") adopted monitoring and reporting rules for disposal wells in certain seismically-active areas, which rules require operators of disposal wells located in the Arbuckle Formation to record injection

pressure and volume measurements on a daily basis and provide such data to the OCC upon request, and further requires, as part of its agency practice, that disposal wells within a six mile radius of designated seismic "areas of interest," regardless of formation, have their pressures and volumes recorded on a daily basis and provided to the OCC upon request.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of oil or natural gas from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into targeted subsurface formations to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs. Hydraulic fracturing typically is regulated by state oil and natural gas commissions or similar state agencies, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final CAA regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; announced its intent to propose in the first half of 2015 effluent limit guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and issued in May 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the federal Bureau of Land Management ("BLM") issued a revised proposed rule containing disclosure requirements and other mandates for hydraulic fracturing on federal lands and the agency is now analyzing comments to the proposed rulemaking and is expected to promulgate a final rule in the first half of 2015. Moreover, there have been public concerns expressed about naturally occurring radioactive materials being detected in flow back water resulting from hydraulic fracturing, particularly in the Marcellus Shale area. This concern could result in further regulation in the treatment, storage, handling and discharge of flow back water generated from these activities that, if implemented, could limit drilling or increase the costs of drilling in affected regions.

Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, some states, including Oklahoma and West Virginia, where we operate, have adopted, and other states are considering adopting legal requirements that could impose more stringent permitting, disclosure or well construction requirements on hydraulic fracturing activities. States could elect to prohibit hydraulic fracturing altogether, such as the State of New York announced in December 2014. Local government may also seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate or where we own a working interest, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. Also, the EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a draft report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer-review in the first half of 2015. These existing or any future studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing

To our knowledge, there have been no material citations, suits, or contamination of potable drinking water arising from our fracturing operations. We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our general liability and excess liability insurance policies would cover third-party claims related to hydraulic fracturing operations and associated legal expenses in accordance with, and subject to, the terms of such policies.

Air Emissions

The Clean Air Act, as amended ("CAA"), and comparable state laws and regulations govern emissions of various air pollutants through air emissions standards, construction and operating permit programs and the imposition of other compliance requirements. Air emissions from some equipment found at our operations or other operations in which we own an interest, such as gas compressors, are potentially subject to regulations under the CAA or equivalent state and local regulatory programs, although many small air emission sources are expressly exempt from such regulations. To the extent that these air emissions are regulated, they are generally regulated by permits issued by state regulatory agencies. While the need to obtain permits has the potential to delay the development of oil and natural gas projects, to date, we believe that no unusual difficulties have been encountered in obtaining air permits. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in December 2014, the EPA published a proposed regulation that it expects to finalize by October 1, 2015 that would revise the National Ambient Air Quality Standard for ozone, recommending a standard between 65 to 70 parts per billion ("ppb") for both the 8-hour primary and secondary standards protective of public health and public welfare. If the EPA lowers the ozone standard, states could be required to implement new more stringent regulations, which could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our capital expenditures and operating costs, which could adversely impact our business.

Climate Change

Based on findings made by the EPA that emissions of carbon dioxide, methane, and other greenhouse gases ("GHGs") present an endangerment to public health and the environment because emissions of such gases are contributing to the warming of the Earth's atmosphere and other climatic changes, the EPA has adopted regulations under existing provisions of the CAA that, among other things, establish Prevention of Significant Deterioration ("PSD") construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that typically are established by the states. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities that exceed GHG emission thresholds. In addition, the EPA adopted rules requiring the monitoring and annual reporting of GHGs from certain sources in the United States, including, among others, onshore and offshore oil and natural gas production facilities, which include certain of our operations. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations that require reporting of GHGs or otherwise limits emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas that we produce. For example, in January 2015, the Obama Administration announced that the EPA is expected to propose in the summer of 2015 and finalize in 2016 new regulations that will set methane emission standards for new and modified oil and natural gas production and natural gas processing and transmission facilities as part of the Administration's efforts to reduce methane emissions from the oil and natural gas sector by up to 45 percent from 2012 levels by 2025.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, floods and other climatic events. If any such physical effects were to occur, they could have an adverse effect on our exploration, development and production interests and operations.

Endangered Species Act

The federal Endangered Species Act, as amended ("ESA"), and similar state laws and other regulatory initiatives restrict activities that may affect endangered or threatened species or their habitats. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. While some of our operations may be located in or near areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts to protected species, and we may be prohibited from conducting operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to our activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service (“FWS”) is required to make a determination on the listing of numerous species as endangered or threatened under the ESA before the completion of the agency's 2017 fiscal year. For example, in March 2014, the FWS announced the listing of the lesser prairie chicken, whose habitat is over a five-state region, including Oklahoma , where we conduct operations, as a threatened species under the ESA. However, the FWS also announced a final rule that will limit regulatory impacts on landowners and businesses from the listing if those landowners and businesses have entered into certain range-wide conservation planning agreements, such as those developed by the Western Association of Fish and Wildlife Agencies (“WAFWA”), pursuant to which such parties agreed to take steps to protect the lesser prairie chicken’s

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habitat and to pay a mitigation fee if its actions harm the lesser prairie chicken's habitat. The presence of protected species or the designation of previously unidentified endangered or threatened species could impair our ability to timely complete well drilling and development and could cause us to incur additional costs arising from species protection measures or become subject to operating restrictions or bans in the affected areas, which delays, costs or restrictions may be significant.

Worker Safety and Health

We are subject to the requirements of the federal Occupational Safety and Health Act, as amended ("OSHA") and comparable state statutes whose purpose is to protect the health and safety of workers. In addition, the OSHA hazard communication standard, the Emergency Planning and Community Right-to- Know Act and comparable state statutes and any implementing regulations require that we organize and/or disclose information about hazardous materials used or produced in our operations and that this information be provided to employees, state and local governmental authorities and citizens. We believe that we are in substantial compliance with all applicable laws and regulations relating to worker health and safety.

Operations on Federal Lands

Performance of oil and natural gas exploration, development and production activities on federal lands, including Indian lands and lands administered by the BLM, may be subject to the National Environmental Policy Act, as amended ("NEPA"). NEPA requires federal agencies, including the BLM and the federal Bureau of Indian Affairs, to evaluate major agency actions, such as the issuance of permits that have the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. Our current and proposed exploration, development and production activities upon federal lands require governmental permits that are subject to the requirements of NEPA. We are not planning any drilling operations on BLM leased acreage in 2015. Our future development of any project on BLM leased acreage will be subject to completion of these environmental assessments and any delays in such completion could result in delays in our exploration or production programs. Permit authorizations under NEPA are subject to protests, appeal or litigation, any or all of which may also delay or halt projects. Moreover, depending on the mitigation strategies recommended in the environmental assessments, we could incur added costs, which could be substantial.

Other Laws and Regulations

Our operations and other operations in which we own a working interest are also impacted by regulations governing the handling, storage, transportation and disposal of naturally occurring radioactive materials. Furthermore, owners, lessees and operators of natural gas and oil properties are also subject to increasing civil liability brought by surface owners and adjoining property owners. Such claims are predicated on the damage to or contamination of land resources occasioned by drilling and production operations and the products derived there from and are often based on negligence, trespass, nuisance, strict liability or fraud.

Industry Segment and Geographic Information

We operate in one industry segment, which is the exploration, development and production of oil, condensate, natural gas and NGLs in the U.S. Our current operational activities are conducted in, and our consolidated revenues are generated from, markets exclusively in the U.S. For additional information relating to our disclosure of revenues, profits and total assets in the segment in which we operate, please see Item 8. ''Financial Statements and Supplementary Data" included in this Form 10-K.

Filings of Reserve Estimates with Other Agencies

Previously, we filed with the Canadian System for Electronic Document Analysis and Retrieval ("SEDAR") revised forms related to our oil and natural gas reserves. The forms provided additional information to ensure compliance with Canadian National Instrument 51-101, "Standards of Disclosure for Oil and Gas Activities" ("NI 51-101"), as required by the Alberta Securities Commission and the Toronto Stock Exchange. The filings did not affect any of our filings with the SEC and were not considered part of our Form 10-K.

On December 16, 2011, the applicable provincial commissions in Canada issued a decision document which granted us exemptive relief from the disclosure requirements contained in NI 51-101. As a result, we are no longer required to comply with the requirements of NI 51-101 and accordingly, are not required to file Form 51-101F1, “Statement of Reserves Data and Other Oil and Gas Information,” revised Form 51-101F2, “Report of Reserve Data by Independent Qualified Reserves Evaluator,” and revised Form 51-101F3, “Report of Management and Directors on Oil and Gas Disclosure.” In lieu of such filings, we are permitted to provide disclosure with respect to our oil and gas activities in the form permitted by, and in accordance with, the legal requirements of the Securities Act, the Exchange Act and the rules and regulations of the SEC and

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the NYSE MKT. We are required to file such disclosure on SEDAR as soon as practicable after such disclosure is filed with the SEC.

Insurance Matters

As is common in the oil and natural gas industry, we do not insure fully against all risks associated with our business either because such insurance may have been unavailable, because premium costs are considered not in line with our deemed exposure or the risk was deemed acceptable to self-insure. A loss not fully covered by insurance could have a material adverse effect on our financial position, results of operations or cash flows.

We maintain insurance at industry customary levels to limit our financial exposure in the event of a substantial environmental claim resulting from sudden, unanticipated and accidental discharges of certain prohibited substances into the environment. Such insurance might not cover the complete amount of such a claim and would not cover fines or penalties for a violation of an environmental law nor would it cover a gradual pollution loss. In analyzing our operations and insurance needs, and in recognition that we have a large number of individual well locations with varied geographical distribution, we compared premium costs to the likelihood of material loss of production. Based on this analysis, we have elected, at this time, to only carry loss of production or business interruption insurance related to the William's facilities and plant covering our Marcellus and Utica Shale operations for up to one year. We carry limited property insurance. Our control of well limits are based upon our assessment of the risk and consideration of the cost of the insurance. See Item 1A. “Risk Factors-The process of drilling for and producing oil and natural gas involves many operating risks that can cause substantial losses, and we may not have enough insurance to cover these risks adequately.”

Employees

As of March 11, 2015, we had 57 employees, all of whom are full time. We use the services of independent consultants and contractors to perform various professional services, including reservoir engineering, land, legal, regulatory reporting, environmental and tax services. On those properties where we are not the operator, we rely on outside operators to drill, produce and market our oil and natural gas. Our employees do not belong to a union or have a collective bargaining organization. Management considers its relationship with its employees to be good.

Corporate Offices

Our corporate office is located at 1331 Lamar Street, Suite 650, Houston, Texas 77010, where we lease 12,823 square feet. Additionally, we rent 6,375 square feet of office space in Clarksburg, West Virginia and 7,002 square feet of office space in Oklahoma City, Oklahoma.

Available Information

Our website address is http://www.gastar.com. Our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to those reports filed or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Exchange Act are made available free of charge on our website as soon as reasonably practicable after we have electronically filed the material with or furnished it to the SEC.

The public may also read and copy any materials we have filed with the SEC at the SEC’s Public Reference Room at 100 F Street, NE, Room 1580, Washington, DC 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-800-SEC-0330. The SEC maintains an internet website that contains our reports, proxy and information statements and our other SEC filings. The address of that site is www.sec.gov.

None of the information on our website should be considered incorporated into or a part of this Form 10-K.

We also make available free of charge on our internet website at www.gastar.com under the “corporate governance” tab our:

- Code of Conduct and Ethics;
- Corporate Governance Guidelines;
- Audit Committee Charter;
- Nominating and Governance Committee Charter:
- Compensation Committee Charter;
- Reserves Review Committee Charter; and
- Whistleblower Procedure.

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Item 1A. Risk Factors

In addition to the other information set forth elsewhere in this Form 10-K, you should carefully consider the following material risk factors associated with our business and the oil and natural gas industry in which we operate. If any of the events described below occur, our business, financial condition, results of operations, liquidity or access to the capital markets could be materially adversely affected. There may be additional risks that are not presently material or known.

An investment in Gastar is subject to risks inherent in our business. The trading price of our common shares will be affected by the performance of our business relative to, among other things, competition, market conditions and general economic and industry conditions. The value of an investment in Gastar may decrease, resulting in a loss.

We have incurred significant net losses since our inception and may incur additional significant net losses in the future.

With the exception of the one-time sale of our Australian properties in 2009, recognition of a $27.7 million non-cash gain on acquisition of assets at fair value for the Chesapeake acquisition, and subsequent sale of certain properties acquired from Chesapeake, which resulted in net income of $40.0 million in 2013, and recognition of a $23.9 million gain attributable to the change in mark to market of commodity derivatives contracts held at December 31, 2014 and an $8.6 million net arbitration settlement which resulted in net income of $36.5 million in 2014, we have not been profitable since we started our business. Our capital has been employed in an increasingly expanding oil and natural gas exploration and development program, with our focus on finding significant oil and natural gas reserves and producing from them over the long-term rather than focusing on achieving immediate net income. The uncertainties described in this Item 1A. “Risk Factors” and elsewhere in this Form 10-K may impede our ability to ultimately find, develop and exploit natural gas and oil reserves. Our failure to achieve profitability in the future could materially adversely affect our ability to raise additional capital and continue our exploration and development program.

Oil, condensate, natural gas and NGLs prices are volatile. A substantial or extended decline in commodity prices may significantly and negatively affect our financial condition and results of operations. Additionally, our results are subject to commodity price fluctuations related to seasonal and market conditions and reservoir and production risks.

The success of our business depends primarily on the market prices of oil, condensate, natural gas and NGLs. Oil and natural gas commodity prices are set by broad market forces, which have been and will likely continue to be volatile in the future. Recently, commodity prices have declined precipitously as a result of several factors, including increased worldwide supplies, a stronger U.S. dollar, weather factors and strong competition among oil producing countries for market share. Specifically, prices for WTI - other as published by Plains All American have declined from a monthly average of $101.68 per barrel in June 2014 to a monthly average of $44.46 per barrel in January 2015. The Henry Hub spot market price of natural gas has declined from a monthly average of $4.77 per MMBtu in March 2014 to a monthly average of $2.99 per MMBtu in January 2015.

Lower realized prices also may reduce the amount of oil, condensate, natural gas or NGLs that we can produce economically. Prices for oil, condensate, natural gas and NGLs are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for oil, condensate, natural gas or NGLs, market uncertainty and a variety of additional factors that are beyond our control. These factors include, but are not limited to:

- The domestic and foreign supply and demand of oil, condensate, natural gas and NGLs;
- Volatile trading patterns in the commodity futures markets;
- Overall economic conditions and market uncertainty;
- Weather conditions;
- The cost of exploring for, developing, producing, transporting and marketing natural gas, condensate, oil and NGLs;
- The proximity to, and capacity of, natural gas pipelines and other transportation facilities;
- Political conditions in the Middle East and other oil producing regions, such as Venezuela;
- Domestic and foreign governmental regulations; and
- The price and availability of competing alternative fuels.

The long-term effect of these and other factors on the prices of oil, condensate, natural gas and NGLs are uncertain. Prolonged or substantial declines in these commodity prices may have the following effects on our business:

- Adversely affecting our financial condition, liquidity, ability to finance planned capital expenditures and results of operations and our ability to meet our financial covenants under our debt agreements;
- Reducing the amount of oil, condensate, natural gas and NGLs that we can produce economically;

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- Causing us to delay or postpone some of our capital projects;
- Reducing our revenues, operating income or cash flows;
- Reducing the amounts of our estimated proved oil and natural gas reserves;
- Reducing the carrying value of our oil and natural gas properties;
- Reducing the standardized measure of discounted future net cash flows relating to oil and natural gas reserves;
- Reducing or eliminating our ability to pay dividends on our outstanding preferred stock; and
- Limiting our access to sources of capital, such as equity and long-term debt.

Our success is influenced by oil, condensate, natural gas and NGLs prices in the specific areas where we operate, and these prices may be lower than prices at major markets.

Regional oil, condensate, natural gas and NGLs prices may move independently of broad industry price trends. Because some of our operations are located outside major markets, we are directly impacted by regional prices regardless of Henry Hub, WTI or other major market pricing. During 2014, approximately 24% of our natural gas production was priced based on the Henry Hub basis point and 76% was priced based on the TETCO M2 basis point. At December 31, 2014, the Henry Hub spot price was $3.14 per MMBtu, compared to the TETCO M2 basis point pricing of $1.74 per MMBtu. Low natural gas prices in any or all of the areas where we operate would negatively impact our financial condition and results of operations. During 2014, approximately 81% and 19% of our oil and condensate production was produced in the Mid-Continent and the Marcellus Shale, respectively, where we realized an average price per barrel of $88.84 and $50.96, respectively, excluding the impact of hedging activities and arbitration settlement for the year. This compares to the daily unweighted average WTI posted price of $89.49 per barrel for 2014. For the year ended December 31, 2014, our realized NGLs prices for Marcellus Shale and Mid-Continent NGLs production represented approximately 27% and 36%, respectively, of the full-year 2014 daily unweighted average WTI - other posted price of $89.49, excluding the impact of hedging activities and arbitration settlement for the year. For the year ended December 31, 2014, our realized natural gas prices for Appalachian Basin and Mid-Continent production excluding the impact of hedging activities and arbitration settlement represented approximately 72% and 98%, respectively, of the full-year 2014 daily unweighted average Henry Hub posted price of $4.34.

Our development operations will require substantial capital expenditures. Our failure to obtain the funds for necessary future growth capital expenditures could have a material adverse effect on our business, results of operations, financial condition and ability to pay distributions to our preferred stockholders and to service our indebtedness.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial growth capital expenditures in our business for the development, production and acquisition of oil and natural gas reserves. These expenditures will reduce the amount of cash available for distribution to our preferred stockholders and to service our indebtedness. Our capital budget for 2015 totals $102.5 million, and we expect to fund these expenditures using existing cash balances, cash generated internally from our operations, borrowings under our revolving credit facility and the possible issuance of debt or equity securities or some combination thereof.

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, condensate, natural gas and NGLs that we produce from existing wells;
- The prices at which we sell our production;
- The costs of developing and producing our oil and natural gas production;
- 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 capital markets.

If the borrowing base under our revolving credit facility or our cash flow from operations decreases as a result of lower oil or natural gas prices, operating difficulties, declines in estimated oil and natural gas reserves or production or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed to fund our growth capital expenditures, our ability to access the capital markets may be limited by our financial condition at the time of any such financing or offering and the covenants in our existing debt agreements, as well as by adverse market conditions resulting from, among other things, general economic conditions and contingencies and uncertainties that are beyond our control.

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Our failure to obtain the funds for necessary future growth capital expenditures could have a material adverse effect on our business, results of operations, financial condition and ability to pay distributions to our preferred stockholders and to service our indebtedness. Even if we are successful in obtaining the necessary funds, the terms of such financings could limit our ability to pay distributions to our preferred stockholders and to service our indebtedness. In addition, incurring additional debt may significantly increase our interest expense and financial leverage, and issuing additional preferred equity will increase the aggregate amount of cash required to make distributions to preferred stockholders.

We may not be able to generate sufficient cash or cash flows, as applicable, to service all of our indebtedness or to meet financial covenants under our debt agreements and may be forced to take other actions to satisfy our obligations under our indebtedness, which may not be successful.

Our ability to make scheduled payments on or to refinance our indebtedness obligations and to meet related financial covenants applicable to our debt instruments, including our Revolving Credit Facility and the Notes, depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness, including the Notes.

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

As of March 9, 2015, the borrowing base under our Revolving Credit Facility was increased to and is currently $200.0 million, and there are $55.0 million in borrowings outstanding under the Revolving Credit Facility. Our next scheduled borrowing base redetermination is expected to occur in November 2015. Our borrowing base is determined semi-annually by our lenders and is based on our proved reserves and the value attributed to those reserves. If commodity prices decline, the borrowing base under our Revolving Credit Facility could be reduced, resulting in a reduction of available credit and the potential requirement for us to repay outstanding indebtedness in excess of the redetermined borrowing base, if any. In addition, we may not be able to access adequate funding under our Revolving Credit Facility as a result of a decrease in our borrowing base due to the issuance of new indebtedness or inability on the part of our lending counterparties to meet their funding obligations and the inability of other lenders to provide additional funding to cover the defaulting lender's portion. As a result, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out our business plan, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

Hedging of our production may result in losses or prevent us from benefiting to the fullest extent possible from increases in prices for oil and natural gas.

We have entered into New York Mercantile Exchange (“NYMEX”) futures contracts as hedges on approximately 637,000 Bbls of crude production, 11.4 Bcf of natural gas production and 69,000 Bbls of NGLs production in 2015, 532,000 Bbls of crude production and 1.5 Bcf of natural gas production in 2016, 373,000 Bbls of crude production in

2017, and 103,000 Bbls of crude production in 2018 as of December 31, 2014. Although these hedges may partially protect us from declines in commodity prices, in light of recent significant declines in oil and natural gas prices, the continued benefit these hedges provide will diminish should energy commodities futures market pricing improve. In addition, the use of these arrangements also may limit our ability to benefit from significant increases in the prices of oil, condensate, natural gas and NGLs.

Any disruptions in production, development of proved oil and natural gas reserves, or our ability to process and sell oil, condensate, natural gas and NGLs from our properties in the Appalachian Basin would have a material adverse effect on our results of operations or reduce future revenues.

Our current production is geographically concentrated in the Appalachian Basin and the Mid-Continent. Approximately 39% of our oil, condensate, natural gas and NGLs revenues before the impact of hedges and approximately 67% of our total proved reserves for the year ended December 31, 2014 were attributable to our properties in the Appalachian Basin. Production in the Appalachian Basin could unexpectedly be disrupted or curtailed due to reservoir, mechanical or third-party gathering system or processing plant problems.

The majority of our production from this area is dedicated to SEI, who agreed to utilize the midstream facilities of a third-party gathering system operated by Williams. During 2013, our Marcellus Shale production was significantly curtailed due to issues with high line pressures and unscheduled downtime on the gathering system operated by Williams that services our Marcellus West properties.

Approximately 61% of our oil, condensate, natural gas and NGLs revenues, before the impact of hedges, and approximately 33% of our total proved reserves for the year ended December 31, 2014 were attributable to our properties in the Mid-Continent. Production in the Mid-Continent could unexpectedly be disrupted or curtailed due to reservoir or mechanical problems.

Our ability to market our oil, condensate, natural gas and NGLs may be impaired by capacity constraints and availability of the gathering systems and pipelines that transport our oil, condensate, natural gas and NGLs.

The availability of a ready market for our oil, condensate, natural gas and NGLs production, particularly in the Appalachian Basin, depends on the proximity of our reserves to and the capacity of natural gas gathering and processing systems, pipelines and trucking or terminal facilities. We do not own or operate any natural gas lines or distribution facilities and rely on third parties to construct additional interstate pipelines to increase our ability to bring our production to market. We enter into agreements with companies that own pipelines used to transport natural gas from the wellhead to contract destination. Those pipelines are limited in size and volume of natural gas flow.

There are a limited number of natural gas purchasers and transporters in the Marcellus and Utica Shales in the Appalachian Basin of West Virginia and central and southwestern Pennsylvania. For the year ended December 31, 2014, SEI accounted for substantially all of our revenues from the Marcellus Shale. If SEI was to cease purchasing and Williams was to cease gathering, processing or transporting our natural gas in the Appalachian Basin and we were unable to contract with another purchaser and/or gatherer, processor or transporter, it would have a material adverse effect on our financial condition, future cash flows and the results of operations.

Delays in the commencement of operations of new pipelines, the unavailability of new pipelines or other facilities due to market conditions, mechanical reasons or otherwise could have an adverse impact on our results of operations and financial condition. We estimate that gathering system downtime during the year ended December 31, 2013 resulted in reduced production of approximately 1.1 MBoe/d, or 13% of total production for the year ended December 31, 2013, which reflected the incremental production for the unscheduled downtime assuming an average daily production rate equal to the average daily production immediately prior to the downtime at our actual average monthly sales prices. On July 16, 2013, we initiated an arbitration proceeding requesting damages against the gathering system operator for, among other claims, failure to timely construct certain gathering and processing facilities, maximize the net value of produced condensation, and fractionate and purchase NGLs as provided in the agreements. The disputes were subsequently settled between both parties on June 17, 2014.

In West Virginia and southwestern Pennsylvania, key issues to development include, but are not limited to, limited pipeline infrastructure and access, water access and disposal issues to support operations and limited industry services. All of these factors could have an adverse effect on our ability to effectively conduct exploration and development activities.

Further, interstate transportation and distribution of natural gas is regulated by the federal government through the FERC. FERC sets rules and carries out administratively the oversight of interstate markets for natural gas and other energy policy. Additionally, state regulators have powers over sale, supply and delivery of oil and natural gas within their state borders. While we employ certain companies to represent our interests before state regulatory agencies, our interests may not receive favorable rulings from any state agency, or some future occurrence may drastically alter our ability to enter into contracts or deliver natural gas to the market.

Legislation or regulatory initiatives intended to address seismic activity could increase our costs of compliance and delay or restrict our ability to dispose of produced water generated by our drilling and production operations, which could have a material adverse effect on our business, results of operations and financial condition.

We inject into disposal wells significant volumes of produced water generated in connection with our drilling and production operations, pursuant to permits issued to us by governmental authorities overseeing such disposal activities. While these permits are issued pursuant to existing laws and regulations, these legal requirements are subject to change, which could result in the imposition of more stringent operating constraints or new monitoring and reporting requirements, owing to, among other things, concerns of the public or governmental authorities regarding such disposal activities. There exists a growing concern that the injection of produced water into belowground disposal wells triggers seismic activity in certain areas, including Oklahoma, where we operate. In response to these concerns, regulators in some states are pursuing initiatives

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designed to impose additional requirements in the permitting of produced water disposal wells or otherwise to assess any relationship between seismicity and the use of such wells. For example, in Oklahoma, the governor announced in September 2014 the creation of a Coordinating Council on Seismic Activity, the purpose of which is to help researchers, policymakers, regulators and oil and natural gas industry study seismicity in the state, and the Utility and Environment Committee of the Oklahoma House of Representatives also has considered what, if any, correlations exist between disposal wells and seismic activity in the state. Moreover, in September 2014, the Oklahoma Corporation Commission ("OCC") adopted monitoring and reporting rules for disposal wells in certain seismically-active areas, which rules require operators of disposal wells located in the Arbuckle Formation to record injection pressure and volume measurements on a daily basis and provide such data to the OCC upon request, and further requires, as part of its agency practice, that disposal wells within a six mile radius of designated seismic "areas of interest," regardless of formation, have their pressures and volumes recorded on a daily basis and provided to the OCC upon request.

Approximately 64% of our proved reserves are classified as proved developed non-producing or proved undeveloped at December 31, 2014 and may ultimately prove to be less than current reserves estimates.

At December 31, 2014, approximately 64% of our total proved reserves were classified as proved developed non-producing or proved undeveloped. It will take approximately $602.2 million of capital to re-complete or drill our non-producing and undeveloped locations. Our estimate of proved reserves at December 31, 2014 assumes that we will spend in 2015 and 2016 development capital expenditures to develop these reserves of $36.6 million and $141.7 million, respectively. Further, our drilling efforts may be delayed or unsuccessful and actual reserves may prove to be less than current reserve estimates, which could have a material adverse effect on our financial condition, future cash flows and our results of operations. Absent significant price increases, the sustained lower oil and natural gas prices experienced in the second half of 2014 and the current year will continue to impact our proved reserves and related PV-10 adversely as the prices used for such estimates under SEC rules are based on the trailing 12-month unweighted average prices, which were substantially higher at December 31, 2014 than current oil and natural gas prices. Lower prices used in estimating proved reserves may result in a reduction in volumes due to economic limits or render undeveloped reserves non-economic, which in turn may make it more likely that we will incur impairment charges in the future against our oil and natural gas properties under full cost accounting. In addition, oil and natural gas prices sustained at current or lower levels and the resultant impact such prices may have on our drilling economics and our ability to raise capital could require us to re-evaluate and postpone our development drilling, which could result in the reduction of some of our proved undeveloped reserves.

Oil and natural gas reserves are depleting assets, and the failure to replace our reserves would adversely affect our production and cash flows.

Our future oil, condensate, natural gas and NGLs production depends on our success in finding or acquiring new reserves. If we fail to replace reserves, our level of production and cash flows would be adversely impacted. Production from oil and natural gas properties decline as reserves are depleted, with the rate of decline depending on reservoir characteristics. Our total proved reserves will decline as reserves are produced unless we conduct successful exploration and development activities and/or acquire properties containing proved reserves. Our ability to make the necessary capital investment to maintain or expand our asset base of oil and natural gas reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. Further, we may not be successful in exploring for, developing or acquiring additional reserves, which could have a material adverse effect on our financial condition, future cash flows and the results of operations.

Exploration is a high risk activity, and our participation in drilling activities may not be successful.

Our future success will largely depend on the success of our exploration drilling program. Participation in exploration drilling activities involves numerous risks, including the risk that no commercially productive oil or natural gas reservoirs will be discovered. The cost of drilling, completing and operating wells is often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including, but not limited to:

- Unexpected drilling conditions;
- Blowouts, fires or explosions with resultant injury, death or environmental or natural resource damages;

- Pressure or irregularities in formations;
- Environmental hazards, such as natural gas leaks, crude oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the environment;
- Uncontrollable flows of natural gas, oil, brine water or drilling fluids;
- Equipment failures or accidents;

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- Adverse weather conditions;
- Compliance with existing and any future governmental laws and regulations; and
- Shortages or delays in the availability of drilling rigs and the delivery of equipment or obtaining water for hydraulic fracturing operations.

We use available seismic data to assist in the location of potential drilling sites. Even when properly used and interpreted, 2-D and 3-D seismic data and other visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators. They do not allow the interpreter to know conclusively if hydrocarbons are present or economically producible. Poor results from our drilling activities would have a material adverse effect on our financial condition, future cash flows and results of operations. In addition, using seismic data and other advanced technologies involves substantial upfront costs and is more expensive than traditional drilling strategies, and we could incur losses as a result of these expenditures.

Reserve estimates depend on many factors and assumptions, including various assumptions that are based on conditions in existence as of the dates of the estimates, which may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions could materially affect the quantities and present values of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and various assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves.

There are many uncertainties inherent in estimating oil and natural gas reserves and their values, many of which are beyond our control. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas or oil that cannot be measured in an exact manner. Estimates of economically recoverable oil or natural gas reserves and of future net cash flows necessarily depend on many variables and assumptions, such as:

- Historical oil or natural gas production from that area, compared with production from other producing areas;
- Assumptions concerning the effects of regulations by governmental agencies;
- Assumptions concerning future prices;
- Assumptions concerning future transportation and operating costs;
- Assumptions concerning severance and excise taxes; and
- Assumptions concerning development costs and workover and remedial costs.

Any of these variables or assumptions could vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil or natural gas attributable to any particular group of properties, classifications of those reserves based on risk recovery and estimates of the future net cash flows expected from them prepared by different engineers, or by the same engineer at different times, may vary substantially. Because of this, our reserve estimates may materially change at any time.

You should not consider the present values of estimated future net cash flows referred to in this Form 10-K to be the current market value of the estimated reserves attributable to our properties. The estimated discounted future net cash flows from proved reserves for all periods from 2010 to 2014 are based on the 12-month unweighted arithmetic average of the first-day-of-the-month prices and costs in effect when the estimate is made. Current or actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as:

- The amount and timing of actual production;
- Supply and demand for oil or natural gas;
- Actual prices received for oil or natural gas in the future being different than those used in the estimate;
- Curtailments or increases in consumption of oil or natural gas;
- Changes in governmental regulations or taxation; and
- The timing of both production and expenses in connection with the development and production of oil or natural gas properties.

In this report, the net present value of estimated future net revenues of our proved reserves at December 31, 2014 is calculated using the historical 12-month unweighted arithmetic average of the first-day-of-the-month prices which are substantially above current oil and natural gas prices. These average prices and the 10% discount rate are not necessarily the

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most appropriate price or discount factor based on prices and interest rates in effect from time to time and risks associated with our reserves or the oil and natural gas industry in general.

Future downward revisions of the present value of our proved reserves and increased drilling expenditures without current additions to proved reserves may lead to write downs in the carrying value of our oil and natural gas properties. We are subject to the full cost ceiling limitation which has resulted in past write-downs of estimated net reserves and may result in a write-down in the future if commodity prices continue to decline.

Under the full cost method of accounting, we are subject to quarterly calculations of a “ceiling” or limitation on the amount of our oil and natural gas properties that can be capitalized on our balance sheet. We may experience write downs of the carrying value of our oil and natural gas properties in the future if the present value of our proved oil and natural gas reserves is lower than our remaining unamortized capitalized costs. If the net capitalized costs of our oil and natural gas properties exceed the cost ceiling, we are subject to a ceiling test write-down of our estimated net reserves to the extent of such excess. If required, it would reduce earnings and impact stockholders’ equity in the period of occurrence and result in lower amortization expense in future periods. The discounted present value of our proved reserves is a major component of the ceiling calculation and represents the component that requires the most subjective judgments. The risk that we will be required to write down the carrying value of oil and natural gas properties increases when natural gas and crude oil prices are depressed or volatile similar to the current market. In addition, a write-down of proved oil and natural gas properties may occur if we experience substantial downward adjustments to our estimated proved reserves, if there are differences in timing between the incurrence of significant costs of exploration or development activities and the recognition of significant proved reserves resulting from such activities and if we experience unsuccessful drilling activities. Expense recorded in one period may not be reversed in a subsequent period even though higher natural gas and crude oil prices may have increased the ceiling applicable in the subsequent period. Absent significant price increases, the sustained lower oil and natural gas prices experienced in the second half of 2014 and the current year will continue to impact our proved reserves and related PV-10 adversely as the prices used for such estimates under SEC rules are based on the trailing 12-month unweighted average prices, which were substantially higher at December 31, 2014 than current oil and natural gas prices. Lower prices used in estimating proved reserves may result in a reduction in volumes due to economic limits or render undeveloped reserves non-economic, which in turn may make it more likely that we will incur impairment charges in the future against our oil and natural gas properties under full cost accounting.

The limited availability or high costs of hydraulic fracturing services in our current operating areas could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

Our industry is cyclical and, from time to time, there is a shortage of materials, equipment, supplies and services, such as drilling rigs, fracture stimulation services and tubulars, well servicing equipment, gathering systems and transportation pipelines. During these periods, the costs and delivery times of those materials, equipment, supplies and services necessary to execute our drilling program are substantially greater. Shortages of fracturing equipment, water for hydraulic fracturing activities, and crews required for complex horizontal well completions in the Appalachian Basin or Mid-Continent area could delay or adversely affect our development and exploration operations or cause us to incur significant expenditures that are not included in our capital budget. Delays could also have an adverse effect on our results of operations, including the timing of the initiation of production from new wells. See “—Federal, state and local legislation and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect our production” for a discussion of legislative and regulatory initiatives that could significantly restrict hydraulic fracturing and therefore make it more difficult or costly for us to perform hydraulic fracturing.

We cannot control the activities on properties we do not operate, which may affect the timing and success of our future operations.

Other companies operate some of the properties in which we have an interest, specifically the Mid-Continent oil play. As a result, we have a limited ability to exercise influence over operations for these properties or their associated costs. Our dependence on the operator and other working interest owners for these projects and our limited ability to influence operations and associated costs could have a material adverse effect on the realization of our targeted returns on capital in drilling or acquisition activities. The success and timing of our drilling and development activities on properties operated by others therefore depend upon a number of factors that are outside of our control, including:

- Timing and amount of capital expenditures;
- The operator’s expertise and financial resources;
- Approval of other participants in drilling wells; and
- Selection of technology.

As of December 31, 2014, 145 gross (34.0 net) wells in which we have an interest were operated by other companies.

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The indenture governing our senior secured notes and the agreement governing our revolving credit facility impose significant operating and financial restrictions, which may prevent us from pursuing certain business opportunities and restrict our ability to operate our business.

The indenture governing our 8 5/8% Senior Secured Notes due 2018 (the "Notes") and the documentation governing our current revolving credit facility (the "Revolving Credit Facility") contain customary restrictions on our activities, including covenants that limit our and our subsidiaries' ability to:

- Transfer or sell assets or use asset sale proceeds;
- Incur or guarantee additional debt or issue preferred equity securities;
- Pay dividends, redeem subordinated debt or make other restricted payments;
- Make certain investments;
- Create or incur certain liens on our assets;
- Incur dividend or other payment restrictions affecting our restricted subsidiaries;
- Enter into certain transactions with affiliates;
- Merge, consolidate or transfer all or substantially all of our assets;
- Enter into certain sale and leaseback transactions; and
- Take or omit to take any actions that would adversely affect or impair in any material respect the collateral securing the Notes.

For more information, see Item 8. "Financial Statements and Supplementary Data, Note 4. Long-Term Debt."

The restrictions in the indenture governing the Notes and in the agreement governing our Revolving Credit Facility may prevent us from taking actions that we believe would be in the best interest of our business, and may make it difficult for us to successfully execute our business strategy or effectively compete with companies that are not similarly restricted. We also may incur future debt obligations that might subject us to additional restrictive covenants that could affect our financial and operational flexibility. We cannot assure that we will be granted waivers or amendments to these agreements if for any reason we are unable to comply with these agreements, or that we will be able to refinance our debt on terms acceptable to us, or at all. The breach of any of these covenants and restrictions could result in a default under the indenture governing the Notes or under the agreement governing our Revolving Credit Facility. An event of default under our Revolving Credit Facility could permit some of our lenders to declare all amounts borrowed from them to be due and payable.

If the counterparties to the derivative instruments we use to hedge our business risks default or fail to perform, we may be exposed to risks we had sought to mitigate, which could materially adversely affect our financial condition and results of operations.

We use hedges to mitigate our oil and natural gas price risk with counterparties. If our counterparties fail or refuse to honor their obligations under these derivative instruments, our hedges of the related risk will be ineffective. This is a more pronounced risk to us in view of the recent stresses suffered by financial institutions. We cannot provide assurance that our counterparties will honor their obligations now or in the future. A counterparty's insolvency or inability or unwillingness to make payments required under terms of derivative instruments with us could have a material adverse effect on our financial condition and results of operations. At the date of filing of this Form 10-K, our counterparties were Cargill, Inc., Comerica Bank, N.A., ING Capital Markets LLC, Koch Supply & Trading, LP and Wells Fargo Bank, N.A.

From time to time, we are a party to legal proceedings arising in the ordinary course of business.

From time to time, we are subject to various significant legal proceedings and claims arising in the ordinary course of business. No assurance can be given regarding the outcome of these legal proceedings. Litigation, regardless of outcome or merit, however, can result in substantial costs and diversion of resources from our business. These costs would be reflected in terms of dollar outlay as well as the amount of time, attention and other resources that our management would have to appropriate to the defense of such claims. Considerable legal, accounting and other professional services expenses have been incurred in legal proceedings to date and significant expenditures may continue to be incurred in the future. Defense costs and any adverse outcome could adversely affect our business, financial condition and results of operations. For more information regarding our legal proceedings, see Item 8. “Financial Statements and Supplementary Data, Note 14. Commitments and Contingencies.”

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Deficiencies of title to our leased interests could significantly affect our financial condition.

Our practice in acquiring exploration leases or undivided interests in oil and natural gas leases is not to incur the expense of retaining lawyers to examine the title to the mineral interest prior to executing the lease. Instead, we rely upon the judgment of lease brokers and others to perform the field work in examining records in the appropriate governmental or county clerk's office before leasing a specific mineral interest. This practice is widely followed in the industry. Prior to drilling an exploration well, the operator of the well will typically obtain a preliminary title review of the drillsite lease or spacing unit within which the proposed well is to be drilled to identify any obvious deficiencies in title to the well and, if there are deficiencies, to identify measures necessary to cure those defects to the extent reasonably possible. It does happen, from time-to-time, that the examination made by the operator's title lawyers reveals that the lease or leases are invalid, having been purchased in error from a person who is not the rightful owner of the mineral interest desired. In these circumstances, we may not be able to proceed with our exploration and development of the lease site or may incur costs to remedy a defect, which could affect our financial condition and results of operations.

We are subject to stringent and complex laws and regulations, which may expose us to significant costs and liabilities and adversely affect the cost, manner or feasibility of conducting our business.

Our oil and natural gas exploration, development and production interest and operations are subject to stringent and complex federal, state, regional and local laws and regulations relating to the operation and maintenance of our facilities, including laws regulating removal of natural resources from the ground, the discharge of materials into the environment and otherwise relating to environmental protection. Oil and natural gas operations are also subject to federal, state, regional and local laws and regulations which seek to maintain occupational health and safety standards by regulating the design and use of drilling methods and equipment.

Governmental authorities administering these laws and any implementing regulations require various timely permits, including drilling and environmental permits, before conducting regulated activities and we cannot assure you that such permits will be received. The failure or delay in obtaining the requisite approvals or permits may adversely affect our business, financial condition and results of operations. Additionally, these laws and regulations impose numerous obligations and restrictions that are applicable to our interests and operations including:

- Drilling and abandonment bonds or other financial responsibility assurances;
- Restriction on types, quantities and concentration of materials that may be released into the environment;
- Reports concerning operations;
- Spacing of wells;
- Limits or prohibitions on drilling activities on certain lands lying within wilderness, wetlands and other protected areas;
- The application of specific health and safety criteria addressing worker protection;
- The imposition of substantial liabilities for pollution resulting from our operations;
- Limitations on access to properties;
- Taxation; and
- Other regulatory controls on operating activities.

In addition, regulatory agencies have from time to time imposed price controls and limitations on production by restricting the flow rate of wells below actual production capacity in order to conserve supplies of oil and natural gas. Failure to comply with these laws and regulations applicable to our interests and operations could result in the assessment of administrative, civil and criminal penalties, the imposition of investigatory or remedial obligations and the issuance of orders enjoining or limiting some or all of our operations, any of which could have a material adverse effect on our financial condition. Legal requirements are sometimes unclear or subject to reinterpretation and may be amended in response to economic or political conditions. As a result, it is hard to predict the ultimate future cost of compliance with these requirements or their effect on our interests and operations. In addition, existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws or regulations may have a material adverse effect on our financial condition, future cash flows and the results of operations. For example, in December 2014, the EPA published a proposed regulation that it expects to finalize by October 1, 2015 that would seek to reduce the National Ambient Air Quality Standard for ozone to between 65 and 70 ppb for both the 8-hour primary and secondary standards. Compliance with these or other new legal requirements could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our expenditures and operating costs, which could adversely impact our business.

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Federal, state and local legislation and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect our production.
Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations such as shales. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing techniques in many of our drilling and completion programs. The process is typically regulated by state oil and natural gas commissions or similar state agencies, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final CAA regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; announced its intent to propose in the first half of 2015 effluent limit guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and issued in May 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the BLM issued a revised proposed rule containing disclosure requirements and other mandates for hydraulic fracturing on federal lands and the agency is now analyzing comments to the proposed rulemaking and is expected to promulgate a final rule in the first half of 2015.
Also, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, some states, including Oklahoma and West Virginia, where we operate, have adopted and other states are considering adopting legal requirements that could impose more stringent permitting, disclosure, or well construction requirements on hydraulic fracturing activities. States could elect to prohibit hydraulic fracturing altogether, such as the State of New York announced in December 2014. Local government also may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic activities in particular. In the event that new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate or where we own working interests, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.
In addition, certain governmental reviews are underway that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. Also, the EPA has commenced a study of the potential environmental effects of hydraulic fracturing activities, with a draft report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer-review in the first half of 2015. These existing or any future studies, depending on their results, could spur initiatives to regulate hydraulic fracturing.
We could incur significant costs and liabilities in responding to contamination that occurs as a result of our operations.
There is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations or in operations in which we own a working interest as a result of our handling of petroleum hydrocarbons and wastes, because of air emissions and wastewater discharges related to our operations, and due to historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we could be subject to strict, joint and several liabilities for the removal or remediation of previously released materials or property contamination. Private parties, including the owners of properties upon which our wells or the wells in which we own a working interest are drilled and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property or natural resource damages. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly well drilling, construction, completion or water management activities, or waste , handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our own results of operations, competitive position or financial condition.

We may not be able to recover some or any of these costs from insurance.

The process of drilling for and producing oil and natural gas involves many operating risks that can cause substantial losses, and we may not have enough insurance to cover these risks adequately.

The oil and natural gas business involves many operating hazards, such as:

- Well blowouts, fires and explosions;
- Surface craterings and casing collapses;
- Road collapses;
- Uncontrollable flows of natural gas, oil, brine, water or well fluids;
- Pipe and cement failures;

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- Formations with abnormal pressures;
- Stuck drilling and service tools;
- Pipeline or tank ruptures or spills;
- Natural disasters; and
- Environmental hazards, such as natural gas leaks, crude oil spills and unauthorized discharges of brine, toxic gases or well fluids.

Any of these events could cause substantial losses to us as a result of:

- Injury or death;
- Damage to and destruction of property, natural resources and equipment;
- Damage to natural resources due to underground migration of hydraulic fracturing fluids;
- Pollution and other environmental damage, including spillage or mishandling of recovered hydraulic fracturing fluids;
- Regulatory investigations and penalties;
- Suspension of operations; and
- Repair, restoration and remediation costs.

We could also be responsible for environmental damage caused by previous owners of property from whom we purchased leases. As a result, we may incur substantial liabilities to third parties or governmental entities. Although we maintain what we believe is appropriate and customary insurance for these risks, the insurance may not be available or sufficient to cover all of these liabilities. If these liabilities are not covered by our insurance, paying them could reduce or eliminate the funds available for exploration, development or acquisitions or result in the loss of our properties.

Certain U.S. federal income tax deductions currently available with respect to oil and gas exploration and development may be eliminated as a result of future legislation.

The President of the United States' budget proposal for the fiscal year 2016 recommended the elimination of certain key U.S. federal income tax preferences currently available to oil and gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for U.S. production activities for oil and natural gas production, and (iv) the extension of the amortization period for certain geological and geophysical expenditures.

It is unclear whether any such changes will actually be enacted or, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of the budget proposal or any other similar change in U.S. federal income tax law could affect certain tax deductions that are currently available with respect to oil and gas exploration and production.

Our oil and natural gas sales and our related hedging activities expose us to potential regulatory risks.

The Federal Trade Commission, the FERC, and the CFTC hold statutory authority to monitor certain segments of the physical and futures energy commodities markets. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales of oil and natural gas and any related hedging activities that we undertake, we are required to observe the market-related regulations enforced by these agencies, which hold substantial enforcement authority. Our sales may also be subject to certain reporting and other requirements. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

To the extent that we enter into transportation contracts with natural gas pipelines that are subject to FERC regulation, we are subject to FERC requirements related to use of such capacity. Any failure on our part to comply with the FERC’s regulations and policies, or with an interstate pipeline’s tariff, could result in the imposition of civil and criminal penalties.

The enactment of the Dodd–Frank Act could have an adverse impact on our ability to hedge risks associated with our business.

On July 21, 2010 new comprehensive financial reform legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), was enacted that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, including us, that participate in that market. The Dodd-Frank Act requires the CFTC, the SEC and other regulators to promulgate rules and regulations implementing the new legislation. Although the

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CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position limits rule was vacated by the United States District Court for the District of Colombia in September of 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and trade-execution. In addition, the CFTC and bank regulators have proposed margin requirements for uncleared swaps. Although we expect to qualify for the end-user exception to both the mandatory clearing and margin requirements for swaps entered into to hedge our commercial risks, the application of such requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. Other regulations also remain to be finalized, and the CFTC recently has delayed the compliance dates for various regulations already finalized. As a result it is not possible at this time to predict with certainty the full effects of the Dodd-Frank Act and CFTC rules on us and the timing of such effects.

The full impact of the Dodd-Frank Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivatives contracts, materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks we encounter or reduce our ability to monetize or restructure our existing derivatives contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures.

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

In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations, the impact of which is not clear at this time.

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

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

Based on findings made by the EPA that emissions of GHGs present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the CAA that, among other things, establish PSD construction and Title V operating permit reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards that typically will be established by the states. In addition, the EPA adopted rules requiring the monitoring and annual reporting of GHGs from certain sources in the United States, including, among others, onshore and offshore oil and natural gas production facilities. Congress has from time to time considered legislation to reduce emissions of GHGs, but there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations that require reporting of GHGs or otherwise limits emissions of GHGs from our equipment and operations could require us to incur significant added costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas we produce. For example, in January 2015, the Obama Administration announced that the EPA is expected to propose in the summer of 2015 and finalize in 2016 new regulations that will set methane emission standards for new and modified oil and natural gas production and natural gas processing and transmission facilities as part of the Administration's efforts to reduce methane emissions from the oil and natural gas sector by up to 45% from 2012 levels by 2025. Finally, it should be noted that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our assets and operations.

Competition in the oil and natural gas industry is intense. We are smaller and have less operating history than many of our competitors, and increased competitive pressure could adversely affect our results of operations.

We operate in a highly competitive environment. We compete with other oil and natural gas companies in all areas of our operations, including the acquisition of exploratory prospects and proven properties. Our competitors include major integrated oil and natural gas companies, numerous independent oil and natural gas companies, individuals and drilling and income programs. Many of our competitors are large, well-established companies that have substantially larger operating staffs and greater capital resources than we do and, in many instances, have been engaged in the oil and natural gas business for a much longer time than we have. These companies may be able to pay more for exploratory prospects and productive oil and natural gas properties and may be able to define, evaluate, bid for and purchase more properties and prospects than our financial and human resources permit. In addition, these companies may be able to spend more on the existing and changing technologies that we believe are and will be increasingly important to the current and future success of oil and natural gas companies. Our ability to explore for oil and natural gas prospects and to acquire additional properties in the future will depend on our ability to conduct our operations, to evaluate and select suitable properties and to consummate transactions in this highly competitive environment. Increased competitive pressure could have a material adverse effect on our financial condition, future cash flows and the results of operations.

Technological changes could affect our operations.

The oil and natural gas industry is characterized by rapid and significant technological advancements and introductions of new products and services utilizing new technologies. As others use or develop new technologies, we may be placed at a competitive disadvantage, and competitive pressures may force us to implement such new technologies at substantial costs. In addition, many other oil and natural gas companies have greater financial, technical and personnel resources that may allow them to enjoy technological advantages and may in the future allow them to implement new technologies before we can. We may be unable to respond to such competitive pressures and implement such technologies on a timely basis or at an acceptable cost. If one or more of the technologies that we currently use or may implement in the future were to become obsolete or if we are unable to use the most advanced commercially available technology, it could have a material adverse effect on our financial condition, future cash flows and the results of operations.

We depend on our key personnel, the loss of which could adversely affect our operations and financial performance.

We depend, to a large extent, on the services of a limited number of senior management personnel and directors. Particularly, the loss of the services of our chief executive officer and chief financial officer could negatively impact our future operations. We have employment agreements with these key members of our senior management team; although, we do not maintain key-man life insurance on any of our senior management. We believe that our success is also dependent on our ability to continue to retain the services of skilled technical personnel. Our inability to retain skilled technical personnel could have a material adverse effect on our financial condition, future cash flows and the results of operations.

Some of our directors may not be subject to suit in the United States.

Two of our seven directors are citizens of Canada. As a result, it may be difficult or impossible to effect service of process within the United States upon those directors, to bring suit against them in the U.S. or to enforce in the U.S. courts any judgment obtained there against them predicated upon any civil liability provisions of the U.S. federal securities laws. Investors should not assume that Canadian courts will enforce judgments of U.S. courts obtained in actions against those directors predicated upon the civil liability provisions of the U.S. federal securities laws or the securities or "blue sky" laws of any state within the United States or will enforce, in original actions, liabilities against those directors upon the U.S. federal securities laws or any such state securities or blue sky laws.

Seasonal weather conditions and regulations adversely affect our ability to conduct drilling activities in some of the areas where we operate.

Oil and natural gas operations in our operating areas can be adversely affected by seasonal weather conditions and regulations designed to protect various wildlife. This limits our ability to operate in those areas and can intensify competition during those months for drilling rigs, oilfield equipment, services, supplies and qualified personnel, which may lead to periodic shortages. These constraints, the resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

Our common stock price has been and is likely to continue to be highly volatile.
The trading price of our common stock is subject to wide fluctuations in response to a variety of factors, including quarterly variations in operating results, announcements of drilling and rig activity, economic conditions in the natural gas and oil industry, general economic conditions or other events or factors that are beyond our control.
In addition, the stock market in general and the market for oil and natural gas exploration companies, in particular, have experienced large price and volume fluctuations that have often been unrelated or disproportionate to the operating results or asset values of those companies. These broad market and industry factors may seriously impact the market price and trading volume of our common stock regardless of our actual operating performance. In the past, following periods of volatility in the overall market and in the market price of a company's securities, securities class action litigation has been instituted against certain oil and natural gas exploration companies. If this type of litigation were instituted against us following a period of volatility in our common stock trading price, it could result in substantial costs and a diversion of our management's attention and resources, which could have a material adverse effect on our financial condition, future cash flows and the results of operations.
Future issuances of our common stock may adversely affect the price of our common stock.
The future issuance of a substantial number of shares of our common stock into the public market, or the perception that such an issuance could occur, could adversely affect the prevailing market price of our common stock. A decline in the price of our common stock could make it more difficult to raise funds through future offerings of our common stock or securities convertible into common stock.
We are able to issue shares of preferred stock with greater rights than our common stock.
Our Amended and Restated Certificate of Incorporation authorize our board of directors to issue one or more series of preferred shares and set the terms of the preferred shares without seeking any further approval from our stockholders. The preferred shares that we have issued rank ahead of our common stock in terms of dividends and liquidation rights. We may issue additional preferred shares that rank ahead of our common stock in terms of dividends, liquidation rights or voting rights. If we issue additional preferred shares in the future, it may adversely affect the market price of our common stock. We have issued in the past, and may in the future continue to issue, in the open market at prevailing prices or in capital markets offerings series of perpetual preferred stock with dividend and liquidation preferences that rank ahead of our common stock.
Because we have no plans to pay dividends on our common stock, stockholders must look solely to appreciation of our common stock to realize a gain on their investment.
We do not anticipate paying any dividends on our common stock in the foreseeable future. We currently intend to retain any future earnings to finance the expansion of our business. In addition, the Notes contain covenants that prohibit the payment of dividends and the Revolving Credit Facility contains covenants that prohibit us from paying cash dividends as long as such debt remains outstanding. The payment of future dividends, if any, will be determined by our board of directors in light of conditions then existing, including our earnings, financial condition, capital requirements, restrictions in financing agreements, business conditions and other factors. Accordingly, stockholders must look solely to appreciation of our common stock to realize a gain on their investment, which may not occur.
If commodity prices continue to drop, we may be limited or unable to lawfully declare dividends on our capital stock.
The Delaware General Corporation Law (the "DGCL") permits payment of dividends out of a corporation's surplus. Surplus is defined as the excess of net assets over the corporation's capital as determined under the DGCL. If commodity prices continue to drop, the net value of our assets will decline and, accordingly, we may not have available surplus from which to lawfully pay or declare dividends on our capital stock.
Item 1B. Unresolved Staff Comments
None.
Item 2. Properties
Our properties consist primarily of oil and natural gas leases in the following areas:
- Mid-Continent area of the U.S. in Oklahoma;
- Marcellus Shale in the Appalachian Basin in West Virginia and central and southwestern Pennsylvania; and
- Utica Shale in the Appalachian Basin in West Virginia.

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Additional information concerning our interests and related natural gas and oil activities in these areas is described under Item 1. "Business" of this Form 10-K.

Production, Prices and Operating Expenses

The following table presents information regarding production volumes, average sales prices received and selected data associated with our sales of oil, condensate, natural gas and NGLs for the periods indicated. Unless otherwise specified, all production volumes in this Form 10-K reflect incremental post-processing NGLs volumes and residual gas volumes with which we are credited under our sales contracts.

	For the Years Ended December 31,		
	2014	2013	2012
Production:			
Oil and condensate (MBbl)	975	515	177
Natural gas (MMcf)	11,598	13,366	10,564
NGLs (MBbl)	801	494	270
Total production (MBoe)	3,708	3,236	2,208
Daily Production:			
Oil and condensate (MBbl/d)	2.7	1.4	0.5
Natural gas (MMcf/d)	31.8	36.6	28.9
NGLs (MBbl/d)	2.2	1.4	0.7
Total daily production (MBoe/d)	10.2	8.9	6.0
Average sales price per unit(1):			
Oil and condensate per Bbl, excluding impact of hedging activities	$84.98	$70.91	$65.45
Oil and condensate per Bbl, including impact of hedging activities(2)	$83.86	$71.04	$70.01
Natural gas per Mcf, excluding impact of hedging activities	$4.11	$3.02	$2.21
Natural gas per Mcf, including impact of hedging activities(2)	$3.84	$3.43	$3.20
NGLs per Bbl, excluding impact of hedging activities	$26.71	$31.59	$28.22
NGLs per Bbl, including impact of hedging activities(2)	$26.53	$31.13	$34.40
Average sales price per Boe, excluding impact of hedging activities	$40.95	$28.58	$19.26
Average sales price per Boe, including impact of hedging activities(2)	$39.78	$30.20	$25.14
Selected operating expenses (in thousands):			
Production taxes(3)	$6,733	$4,651	$2,269
Lease operating expenses(3)	$19,323	$9,456	$6,174
Transportation, treating and gathering(3)	$3,679	$4,006	$4,965
Depreciation, depletion and amortization	$46,180	$32,449	$25,424
Impairment of natural gas and oil properties	$—	$—	$150,787
General and administrative expense	$16,485	$16,961	$12,211
Selected operating expenses per Boe:			
Production taxes(3)	$1.82	$1.44	$1.03
Lease operating expenses(3)	$5.21	$2.92	$2.80
Transportation, treating and gathering(3)	$0.99	$1.24	$2.25
Depreciation, depletion and amortization	$12.45	$10.02	$11.52
General and administrative expense(4)	$4.45	$5.24	$5.53
Production costs(5)	$6.00	$4.05	$4.81

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(1)The year ended December 31, 2014 includes the benefit of a non-recurring revenue adjustment related to an arbitration settlement. Excluding the arbitration settlement adjustment impact, average sales prices would have been as follows:

	For the Year Ended December 31, 2014
Average sales price per unit:	
Oil and condensate per Bbl, excluding impact of hedging activities	$ 81.75
Oil and condensate per Bbl, including impact of hedging activities (2)	$ 80.63
Natural gas per Mcf, excluding impact of hedging activities	$ 3.41
Natural gas per Mcf, including impact of hedging activities (2)	$ 3.14
NGLs per Bbl, excluding impact of hedging activities	$ 27.55
NGLs per Bbl, including impact of hedging activities (2)	$ 27.37
Average sales price per Boe, excluding impact of hedging activities	$ 38.09
Average sales price per Boe, including impact of hedging activities (2)	$ 36.92

(2) The impact of hedging includes the gain (loss) on commodity derivative contracts settled during the periods presented.

(3)The year ended December 31, 2014 includes a non-recurring adjustment to production taxes, lease operating expenses and transportation, treating and gathering related to an arbitration settlement. Excluding the arbitration settlement adjustment impact, production taxes, lease operating expenses and transportation, treating and gathering per Boe would have been as follows:

	For the Year Ended December 31, 2014
Selected operating expenses per Boe:	
Production taxes	$ 1.66
Lease operating expenses	$ 5.26
Transportation, treating and gathering	$ 0.56

(4) General and administrative expenses include non-recurring costs related to acquisitions, severance related to property divestment and corporate migration of $263,000, $4.2 million and $834,000 for the years ended December 31, 2014, 2013 and 2012, respectively. Excluding such costs, general and administrative expenses would have been $4.37 per Boe, $3.95 per Boe and $5.15 per Boe for each respective year.

(5)Production costs include lease operating expenses, insurance, gathering and workover expense and excludes ad valorem and severance taxes. Excluding the arbitration settlement adjustment impact, production costs for the year ended December 31, 2014 would have been as follows:

	For the Year Ended December 31, 2014
Selected operating expenses per Boe:	
Production costs	$ 5.62

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Drilling Activity

The following table shows our drilling activity for the periods indicated.

	For the Years Ended December 31,					
	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Productive	30.0	14.9	11.0	5.7	6.0	1.7
Non-productive	—	—	—	—	—	—
Total	30.0	14.9	11.0	5.7	6.0	1.7
Development wells:						
Productive	11.0	6.0	17.0	8.5	31.0	14.2
Non-productive	—	—	—	—	—	—
Total	11.0	6.0	17.0	8.5	31.0	14.2

On December 31, 2014, we had a total of seven gross (3.5 net) operated wells in the process of being drilled or awaiting fracture stimulation in the Marcellus Shale, one gross (0.5 net) operated well in the process of being drilled or awaiting fracture stimulation in the Utica Shale and three gross (2.9 net) operated wells and ten gross (4.5 net) non-operated wells being drilled or awaiting fracture stimulation in the Mid-Continent.

Exploration and Development Acreage

The following table sets forth our ownership interest in undeveloped and developed acreage in the areas indicated where we own a working interest as of December 31, 2014.

	Undeveloped Acreage		Developed Acreage	
	Gross	Net	Gross	Net
Appalachian Basin, West Virginia and Pennsylvania(1)				
Marcellus West(2)(3)	21,031	8,718	11,030	4,746
Marcellus East	38,869	34,870	3,185	2,936
Total Marcellus Shale area	59,900	43,588	14,215	7,682
Mid-Continent	156,613	74,397	69,159	43,439
Total	216,513	117,985	83,374	51,121

(1) We believe that substantially all of our Appalachian Basin acreage is prospective.
(2) The Marcellus West acreage reflects that Atinum has earned their full joint venture interest.
(3) Approximately 27,900 gross (11,500 net) acres of our Marcellus West acreage, of which approximately 4,300 gross (1,900 net) acres are pending lease finalization, should be prospective for high-pressure, high-deliverability dry natural gas development in the Utica Shale.

Undeveloped Acreage Expirations

The table below summarizes, by year, our gross undeveloped acreage scheduled to expire.

As of December 31,	Appalachian Basin			Total Expiring	% of Total Undeveloped	
	West	East	Mid-Continent	Gross Acres	Gross Acres	
2015	3,354	9,635	47,687	60,676	28	%
2016	2,981	13,315	80,014	96,310	44	%
2017	5,131	52	28,628	33,811	16	%
2018	5,813	7	242	6,062	3	%
2019 and thereafter	2,466	—	42	2,508	1	%

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The table below summarizes our net undeveloped acreage scheduled to expire by year.

As of December 31,	Appalachian Basin			Total Expiring Net Acres	% of Total Undeveloped Net Acres
	West	East	Mid-Continent		
2015	1,375	9,385	21,166	31,926	27 %
2016	1,517	10,945	35,581	48,043	