Gastar Exploration Inc.
Form 10-K
March 10, 2016
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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, 2015

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	38-3531640
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

1331 Lamar Street, Suite 650 Houston, Texas	77010
(Address of principal executive offices)	(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 o No x

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 o No x

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 x No o

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 x No o

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. x

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	o	Accelerated filer	x
Non-accelerated filer	o	Smaller reporting company	o

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 o No x

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, 2015 (the last business day of Gastar Exploration Inc.'s most recently completed second fiscal quarter) was approximately $233.9 million based on the closing price of $3.09 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 7, 2016 was 81,837,275.

DOCUMENTS INCORPORATED BY REFERENCE:

None.

GASTAR EXPLORATION INC. AND SUBSIDIARIES

ANNUAL REPORT ON FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2015

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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," "poten 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 condition;
- cash flow and liquidity;
- timing and results of property divestitures;
- compliance with covenants under our indenture and credit agreements;
- 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;
- availability of capital; and
- prospect development.

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;
- our financial condition, results of operations, revenues, cash flows and expenses;
- the potential need to sell certain assets, restructure our debt or raise additional capital;

- the need to take ceiling test impairments due to lower commodity prices;
- 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 monetize certain assets;

- our ability to raise capital to fund capital expenditures, service our indebtedness or repay or refinance debt upon maturity;
- our ability to successfully complete the sale of certain of our Appalachian Basin assets;
- 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 co-participants 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;
- 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 oil and natural gas 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 oil or natural gas 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 oil and natural gas.

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.

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.

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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, calculated by converting liquids volumes on the basis of $1/6^{th}$ of a barrel of oil, condensate or NGLs per Mcf
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 by converting natural gas volumes on the basis of 6 Mcf of natural gas per barrel
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 by converting liquids volumes on the basis of 1/6th of a barrel of oil, condensate or NGLs per Mcf
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 by converting liquids volumes on the basis of 1/6th of a barrel of oil, condensate or NGLs per Mcf
MMcfe/d	One million cubic feet of natural gas equivalent per day
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 comprising one of our compensation plan awards
psi	Pounds per square inch
PUD	Proved undeveloped reserves

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STACK Play	An acronymic name for a predominantly oil producing play referring to the exploration and development of the Sooner Trend of the Anadarko Basin in Canadian and Kingfisher Counties, Oklahoma.
U.S.	United States
WTI	West Texas Intermediate

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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 have developed the primarily oil-bearing reservoirs of the Hunton Limestone horizontal oil play and are drilling other prospective formations on the same acreage, primarily the Meramec Shale (Middle Mississippi Lime), while we plan to also test the Woodford Shale, along with emerging prospective plays in the shallow Oswego formation and in the Osage formation, a deeper bench of the Mississippi Lime located below the Meramec. These formations comprise what is commonly referred to as the STACK Play. In West Virginia, we have developed liquids-rich natural gas in the Marcellus Shale and have drilled and completed two successful dry gas Utica Shale/Point Pleasant wells on our acreage. On February 19, 2016, we entered into an agreement to sell substantially all of our assets and proved reserves and a significant portion of our undeveloped acreage in the Appalachian Basin for $80.0 million, subject to certain adjustments and customary closing conditions, including obtaining certain required lessor consents to assign (the “Appalachian Basin Sale”). The transaction is expected to close on or before March 31, 2016 with an effective date of January 1, 2016. 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 currently depressed commodity price environment, which make it difficult to fully execute this strategy on a short-term basis. We intend to implement our strategy by focusing on:

- development of our Mid-Continent assets in the STACK Play;
- exploitation of the STACK Play on our Mid-Continent acreage;
- the sale of certain of our properties, including our Appalachian Basin Sale and the possible sale of a portion of our undeveloped STACK Play acreage in the Mid-Continent;
- active management of our drilling programs; and
- effective management and utilization of technological expertise.

Development of our Mid-Continent Assets in the STACK 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 through 2015 with our AMI co-participant in an 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. On December 16, 2015, we completed the acquisition of additional interests in the AMI from our AMI co-participant including working and net revenue interests in 103 gross (10.2 net) producing wells and approximately 15,700 net developed and undeveloped acres in Kingfisher and Garfield Counties, Oklahoma (the “Husky Acquisition”) for an adjusted purchase price of $42.1 million and the conveyance of approximately 11,000 net non-core, non-producing acres in Blaine, Major and Kingfisher Counties, Oklahoma to the sellers. With the closing of the Husky Acquisition, our AMI participation agreements with our AMI co-participant were dissolved and we obtained operatorship of the acquired wells.

Our Mid-Continent development program has been focused on using modern horizontal drilling and multi-stage fracture stimulation technologies to exploit the Hunton Limestone, a predominantly crude oil-bearing reservoir, which has been produced historically using vertical wells with conventional completion techniques. Since 2012, we, along with our former AMI co-participant in the initial AMI and adjacent areas, until such time as we bought out our AMI co-participant, drilled and completed 38 gross (17.9 net) horizontal non-operated wells. As a result of the Husky Acquisition, we now operate each of these wells.

Since we began our operated drilling program in the Hunton Limestone in 2013, we have drilled and completed 22 gross (21.4 net) operated wells, including 17 gross (16.7 net) wells within the West Edmond Hunton Lime Unit ("WEHLU").

To further test the potential of other Mid-Continent formations, during 2015 and to date in 2016, we also participated in three gross (0.1 net) non-operated Woodford Shale wells, two gross (0.1 net) non-operated wells targeting the Oswego, one gross (0.003 net) non-operated well targeting the Osage Shale and six gross (0.5 net) non-operated Meramec Shale wells. Prior to 2015, we participated in one gross (0.1 net) non-operated Mississippian Lime well and two gross (0.1 net) non-operated Woodford Shale well.

Exploitation of the STACK Play on our Mid-Continent Acreage

In addition to Hunton Limestone potential, we believe that our acreage is also prospective in the STACK Play, an area of central Oklahoma that includes oil and natural gas-rich shale formations such as the proven Meramec and Woodford Shales, ranging in depth from 6,000 to 9,000 feet, and emerging prospective plays in the shallow Oswego formation and in the Osage formation, a deeper bench of the Mississippi Lime located below the Meramec. Subsequent to the closing of the Husky Acquisition, our exposure to the STACK Play is approximately 38,100 net acres in the Meramec Shale play, 39,200 net acres in the Osage Shale play, 14,900 net acres in the Oswego formation and 39,200 net acres in the Woodford Shale play.

On September 6, 2015, we spudded our first operated Meramec well, the Deep River 30-1H, with a vertical depth of approximately 7,300 feet and drilled an approximate 5,100-foot lateral and completed it with a 34-stage fracture stimulation. The Deep River 30-1H was placed on flowback on October 28, 2015. The Deep River produced a peak 24-hour rate of 1,094 Boe per day (71% oil) and at a post-peak 60-day average daily production rate of 803 Boe per day (63% oil). Our working interest in the Deep River 30-1H is 100% (NRI 80%). The estimated cost to drill and complete the Deep River 30-1H is approximately $6.5 million.

We spud one gross (1.0 net) well, our second Meramec well, the Holiday Road 2-1H, February 10, 2016 and the well is scheduled to begin completion operations in mid-March 2016. The well was drilled to a total depth of 12,000 feet in approximately 12 days and has a horizontal lateral of approximately 4,300 feet. Our working interest in the Holiday Road 2-1H will not be less than 72% (approximate NRI 57%).

Sale of Certain of our Properties

Due to continued declines in natural gas and NGLs prices in the Appalachian Basin, we suspended our drilling operations in the Appalachian Basin during the second quarter of 2015. On February 19, 2016, we entered into an agreement to sell substantially all of our assets and proved reserves and a significant portion of our undeveloped acreage in the Appalachian Basin for $80.0 million, subject to certain adjustments and customary closing conditions, including obtaining certain required lessor consents to assign. The transaction is expected to close on or before March 31, 2016, with an effective date of January 1, 2016. The proceeds from the Appalachian Basin Sale will be utilized to reduce outstanding borrowings under our revolving credit facility (the "Revolving Credit Facility").

We are currently marketing approximately 26,000 net acres of primarily undeveloped leasehold in Canadian and southeast Kingfisher Counties, Oklahoma. If the sale of such acreage is successful, the proceeds from the sale may be utilized to partially reduce the borrowings outstanding under our Revolving Credit Facility, for lease renewals and for the expansion of our 2016 capital program.

Actively Manage Our Drilling Program

We believe that operating the majority of our capital budget for 2016 will enable us to control the timing and cost of our drilling as well as control operating costs and the marketing of our production. Given the currently depressed commodity price environment and market conditions, control over our costs and expenditures is increasingly important. Due to uncertainty concerning current and future commodity prices and our 2016 capital resources, we have not established our full-year 2016 capital plan. Our preliminary capital budget for 2016 is approximately $37.0 million, excluding other capitalized costs, which contemplates the drilling and completion of a second operated Meramec well for approximately $5.5 million (gross), $3.5 million net for recompletion projects on producing operated wells in Oklahoma, $8.0 million for our participation in non-operated STACK Play drilling and $20.0 million for maintaining our current Oklahoma leasehold position.

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 and the STACK Play wells.

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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 2015. 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 sources of revenue and historical expenditures, please see Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operation.”

Mid-Continent Horizontal Oil Plays

We believe that our acreage is prospective in the STACK Play, an area of central Oklahoma that includes oil and natural gas-rich shale formations such as the proven Meramec and Woodford Shale, ranging in depth from 6,000 to 9,000 feet, and emerging prospective plays in the shallow Oswego formation and in the Osage formation, a deeper bench of the Mississippi Lime located below the Meramec as well as the proven Hunton Limestone horizontal oil play. As of December 31, 2015, we held leases covering approximately 184,900 gross (110,700 net) acres in Garfield, Canadian, Kingfisher, Logan, Blaine and Oklahoma Counties, Oklahoma within the STACK Play.

Our leasing activities primarily located in northwest Kingfisher County, Oklahoma, began in 2012 initially with an AMI co-participant and were expanded to include two additional adjacent prospect areas. Prior to the closing of the Husky Acquisition, our AMI co-participant handled all drilling, completion and production activities, and we handled leasing and permitting activities in certain areas of the AMI. On December 16, 2015, we completed the Husky Acquisition of additional interests in the AMI from our AMI co-participant including working and net revenue interests in 103 gross (10.2 net) producing wells and approximately 15,700 net developed and undeveloped acres in Kingfisher and Garfield Counties, Oklahoma and assumed operatorship of the acquired wells. With the closing of the Husky Acquisition, our AMI participation agreements with our AMI co-participant were dissolved.

On July 6, 2015, we sold certain non-core assets comprised of 38 gross (16.7 net) wells producing approximately net 170 Boe/d (41% oil) for the three months ended March 31, 2015 and approximately 29,500 gross (19,200 net) acres in Kingfisher County, Oklahoma for an adjusted purchase price of $46.5 million. The sale is reflected as a reduction to the full cost pool and we did not record a gain or loss related to the divestiture as it was not significant to the full cost pool.

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 WEHLU 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.

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.

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As of December 31, 2015 and currently as of the date of this report, we had production operations on the following wells completed during 2015 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)	Boe/d[(2)]	% Oil	Date of First Production	Approximate Gross Costs to Drill & Complete ($ millions)
LB 1-1H	60.9%	4,300	791	147	61%	January 23, 2015	$ 4.4
Hubbard 1-23H	87.9%	4,500	63	16	97%	February 19, 2015	$ 6.1
Boss Hogg 1-14H	75.5%	4,300	129	45	70%	February 21, 2015	$ 7.4
Bo 1-23H	64.3%	4,300	547	213	42%	February 28, 2015	$ 5.0
The River 1-22H	39.7%	3,800	1,250	639	26%	March 14, 2015	$ 4.6
Bigfoot 1-9H	72.4%	4,200	161	77	51%	March 17, 2015	$ 5.1
Falcon 1-5H	61.7%	4,100	1,202	496	64%	April 1, 2015	$ 4.4
Dorothy 1-12H	68.2%	3,900	41	13	77%	April 10, 2015	$ 4.5
Polar Bear 1-20H	56.2%	4,300	403	99	88%	May 5, 2015	$ 5.2
Unruh 1-34H	75.9%	4,400	371	242	45%	October 28, 2015	$ 7.3

(1) Represents highest daily gross Boe rate.
(2) Represents gross cumulative production divided by actual producing days through February 29, 2016.

As of December 31, 2015 and currently as of the date of this report, we had production operations on the following operated wells on our WEHLU acreage in the Hunton Limestone formation:

Well Name	Current Working Interest	Approximate Lateral Length (in feet)	Peak Production Rates[(1)] (Boe/d)	Boe/d[(2)]	% Oil	Date of First Production	Approximate Gross Costs to Drill & Complete ($ millions)
Upper Hunton Completions							
Warsaw 33-2H	98.3%	4,900	615	183	50%	February 13, 2015	$ 4.4
Blair Farms 31-1H	98.3%	7,500	509	339	75%	May 7, 2015	$ 5.1
Easton 22-4H	98.3%	5,800	604	285	87%	May 20, 2015	$ 2.9
Jetson 8-2H	98.3%	6,100	353	138	88%	August 19, 2015	$ 4.6
Arcadia Farms 15-2H	98.3%	7,700	444	178	81%	September 13, 2015	$ 3.1
O' Donnell 5-1H	98.3%	4,400	462	223	74%	October 8, 2015	$ 3.2

Lower Hunton Completions								
Warsaw 33-3H	98.3%	6,100	663	173	56%	February 14, 2015	$	6.9
Easton 22-3H	98.3%	6,700	548	354	76%	May 24, 2015	$	4.6
Davis 9-2H	98.3%	6,600	280	206	81%	August 6, 2015	$	6.2
Jetson 8-1H	98.3%	5,800	316	156	59%	August 19, 2015	$	5.5
Davis 9-4H	98.3%	7,700	177	102	98%	October 3, 2015	$	5.5
Arcadia Farms 15-1CH	98.3%	6,800	251	181	69%	October 9, 2015	$	5.9
O'Donnell 5-2CH	98.3%	5,600	521	287	58%	October 9, 2015	$	4.3

(1) Represents highest daily gross Boe rate.

(2) Represents gross cumulative production divided by actual producing days through February 29, 2016.

On September 6, 2015, we spudded our first Meramec well, the Deep River 30-1H, with a vertical depth of approximately 7,300 feet and drilled an approximate 5,100-foot lateral and completed it with a 34-stage fracture stimulation. The Deep River 30-1H commenced flow back on October 28, 2015 and in December 2015, produced at a peak 24-hour rate of 1,094 Boe per day (71% oil) and at a post-peak 60-day average daily production rate of 803 Boe per day (63% oil). Our working interest in the Deep River 30-1H is 100% (NRI 80%). The estimated cost to drill and complete the Deep River 30-1H is approximately $6.5 million. On February 10, 2016, we spudded our second Meramec well, the Holiday Road 2-1H, and the well is scheduled to begin completion operations in mid-March 2016. The well was drilled to a total depth of 12,000 feet in approximately 12 days and has a horizontal lateral of approximately 4,300 feet. Our working interest in the Holiday Road 2-1H will not be less than 72% (approximate NRI 57%).

In 2015 and to date in 2016, we have also elected to participate in eight gross (0.6 net) non-operated Meramec Shale wells, three gross (0.1 net) non-operated Woodford Shale wells, three gross (0.4 net) non-operated wells targeting the Oswego and one gross (0.003 net) non-operated well targeting the Osage Shale. Prior to 2015, we participated in one gross (0.1 net) non-operated

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Mississippian Lime well and two gross (0.1 net) non-operated Woodford Shale wells. We are currently planning to participate in an additional non-operated well targeting the Oswego in Kingfisher County, Oklahoma during the second quarter of 2016.

At December 31, 2015, proved reserves attributable to the Mid-Continent were approximately 41.0 MMBoe, a 21% increase from year-end 2014 reserves of 34.0 MMBoe. As of December 31, 2015, Mid-Continent proved reserves represented approximately 73% of our total proved reserves and 94% of our SEC total proved PV-10 value. Total Mid-Continent proved reserves at year-end 2015 were comprised of approximately 78% of oil, condensate and NGLs reserves compared to 79% at year-end 2014. Approximately 33% of the Mid-Continent year-end 2015 and year-end 2014 reserves were proved developed.

For 2016, our focus is to drill in areas that we believe will result in de-risking of additional acreage within the STACK Play and the renewal of 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 certain acreage that is outside of our drilling focus to reduce net capital expenditures. We are currently marketing approximately 26,000 net acres of primarily undeveloped leasehold in Canadian and southeast Kingfisher Counties, Oklahoma. If the sale of such acreage is successful, the proceeds from the sale may be utilized to partially reduce the borrowings outstanding under our Revolving Credit Facility, for lease renewals and for the expansion of our 2016 capital program.

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

	For the Years Ended December 31,		
Mid-Continent	2015	2014	2013
Production:			
Oil and condensate (MBbl)	1,182	792	189
Natural gas (MMcf)	3,370	2,822	1,095
NGLs (MBbl)	433	332	23
Total Production (MBoe)	2,177	1,594	395
Oil and condensate (MBbl/d)	3.2	2.2	0.5
Natural gas (MMcf/d)	9.2	7.7	3.0
NGLs (MBbl/d)	1.2	0.9	0.1
Total daily production (MBoe/d)	6.0	4.4	1.1
Average sales price per unit[(1)]:			
Oil and condensate (per Bbl)	$46.18	$88.84	$94.80
Natural gas (per Mcf)	$2.57	$4.24	$4.75
NGLs (per Bbl)	$13.15	$31.79	$33.06
Average sales price per Boe[(1)]	$31.67	$58.27	$60.53
Selected operating expenses (in thousands):			
Production taxes	$1,444	$2,940	$820
Lease operating expenses	$19,270	$15,112	$4,019
Transportation, treating and gathering	$14	$40	$3
Selected operating expenses per Boe:			

Production taxes	$0.66	$1.84	$2.08
Lease operating expenses	$8.85	$9.48	$10.17
Transportation, treating and gathering	$0.01	$0.02	$0.01
Production costs(2)	$8.86	$9.50	$10.17

(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.

Our preliminary 2016 Mid-Continent capital budget includes plans for drilling and completion of a second operated Meramec well for approximately $5.5 million, $3.5 million for recompletion projects on producing operated Oklahoma wells, $8.0 million for our participation in non-operated STACK Play drilling and $20.0 million for maintaining our current Oklahoma leasehold position.

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Appalachian Basin

Due to the continued depressed price environment in the Appalachian Basin, we suspended our drilling operations in the Appalachian Basin in the second quarter of 2015. As of December 31, 2015, we had no drilling operations in progress on our Marcellus Shale and Utica/Point Pleasant acreage in Marshall County, West Virginia. On February 19, 2016, we entered into an agreement to sell substantially all of our assets and proved reserves and a significant portion of our undeveloped acreage in the Appalachian Basin for $80.0 million, subject to certain adjustments and customary closing conditions. The transaction is expected to close on or before March 31, 2016 with an effective date of January 1, 2016.

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. As of December 31, 2015, our acreage position in the play was approximately 56,300 gross (36,900 net) acres. We refer to the approximately 27,500 gross (11,500 net) acres reflecting our interest in our Marcellus Shale assets in West Virginia and Pennsylvania subject to our participation agreement (the “Atinum Participation Agreement”) with an affiliate of Atinum Partners Co. Ltd. (“Atinum”) as our “Marcellus West acreage.” We refer to the approximately 28,800 gross (25,400 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.

On September 21, 2010, we entered into the Atinum Participation Agreement 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 then-existing Atinum Participation Agreement. 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 co-participants pursued an initial three-year development program that called for the drilling of 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, 2015, 74 gross (37.0 net) operated Marcellus Shale horizontal wells were capable of production. All of our Marcellus Shale well operations to date were drilled under the Atinum Participation Agreement. The Atinum Participation Agreement expired on November 1, 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, 2015, proved reserves attributable to the Marcellus Shale were approximately 13.6 MMBoe, a 78% decrease from year-end 2014 reserves of 61.0 MMBoe. The decrease was the result of all Marcellus Shale PUD locations being uneconomic at year-end SEC prices. As of December 31, 2015, Marcellus Shale proved reserves represented approximately 24% of our total proved reserves and 6% of PV-10 value. Total Marcellus Shale proved reserves at year-end 2015 were comprised of approximately 43% of oil and condensate and NGLs reserves compared to 45% at year-end 2014. All of the Marcellus Shale year-end 2015 reserves are proved developed compared to 41% at December 31, 2014.

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

Marcellus Shale	For the Years Ended December 31, 2015	2014	2013
Production:			
Oil and condensate (MBbl)	243	182	315
Natural gas (MMcf)	8,241	8,050	9,594
NGLs (MBbl)	779	469	471
Total production (MBoe)	2,395	1,993	2,385
Oil and condensate (MBbl/d)	0.7	0.5	0.9
Natural gas (MMcf/d)	22.6	22.1	26.3
NGLs (MBbl/d)	2.1	1.3	1.3
Total daily production (MBoe/d)	6.6	5.5	6.5
Average sales price per unit(1)(2):			
Oil and condensate (per Bbl)	$16.78	$68.21	$55.61
Natural gas (per Mcf)	$0.80	$4.28	$2.86
NGLs (per Bbl)	$1.85	$23.11	$31.52
Average sales price per Boe(1)(2)	$5.07	$28.97	$25.08
Selected operating expenses (in thousands):			
Production taxes(3)	$1,235	$3,685	$3,805
Lease operating expenses(3)	$4,369	$4,187	$3,181
Transportation, treating and gathering(3)	$1,934	$3,552	$1,176
Selected operating expenses per Boe:			
Production taxes(3)	$0.52	$1.85	$1.60
Lease operating expenses(3)	$1.82	$2.10	$1.33
Transportation, treating and gathering(3)	$0.81	$1.78	$0.49
Production costs(4)	$2.06	$3.50	$1.76

(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:

	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

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 it 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 our successful completion of two Utica Shale wells, log analysis of offsetting wells and recent Utica Shale completions by other nearby operators, we believe that our Marcellus West acreage should be prospective for high-pressure, high-deliverability dry natural gas development in the Utica Shale/Point Pleasant formation. 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. Our working interest in the Simms U-5H is 50.0% (43.2% net revenue interest). We drilled the Blake U-7H to a total vertical depth of 11,100 feet and drilled an approximate 6,600-foot lateral and completed it with a 34-stage fracture stimulation. Our working interest in the Blake U-7H is 50.0% (41.1% net revenue interest). The estimated cost to drill and complete the Blake U-7H was approximately $15.9 million. All of our Utica Shale/Point Pleasant well operations to date were drilled under the Atinum Participation Agreement. The Atinum Participation Agreement expired on November 1, 2015.

At December 31, 2015, proved reserves attributable to the Utica Shale were approximately 1.2 MMBoe, an 83% decrease from year-end 2014 reserves of 7.1 MMBoe. The decrease was the result of all Utica Shale PUD locations being uneconomic at year-end 2015 SEC prices. As of December 31, 2015, Utica Shale proved reserves represented approximately 2% of our total proved reserves and 1% of PV-10 value and were comprised 100% of natural gas reserves. All of the Utica Shale year-end 2015 reserves are proved developed compared to 12% at December 31, 2014.

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

	For the Years Ended December 31,

Utica Shale	2015	2014
Production:		
Natural gas (MMcf)	2,148	725
Total production (MBoe)	358	121
Natural gas (MMcf/d)	5.9	2.0
Total daily production (MBoe/d)	1.0	0.3
Average sales price per unit(1):		
Natural gas (per Mcf)	$0.75	$1.68
Average sales price per Boe(1)	$4.49	$10.10
Selected operating expenses (in thousands):		
Production taxes	$198	$109
Lease operating expenses	$89	$24
Transportation, treating and gathering	$241	$87
Selected operating expenses per Boe:		
Production taxes	$0.55	$0.90
Lease operating expenses	$0.25	$0.20
Transportation, treating and gathering	$0.67	$0.72
Production costs(2)	$0.92	$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.

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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. The prices we receive for our oil, condensate, natural gas and NGLs production are subject to wide fluctuations and depend on numerous factors beyond our control including seasonality, the condition of the United States economy, foreign imports, political conditions in other petroleum producing countries, the actions of the Organization of Petroleum Exporting Countries, domestic regulation, legislation and policies. Decreases in the prices we receive for our oil and gas have had, and could have in the future, an adverse effect on the carrying value of our proved reserves, our revenue, profitability and cash flow from operations. For additional information regarding the prices we receive for our oil, condensate, natural gas and NGLs production, see Item 1A. "Risk Factors - Oil, condensate natural gas and NGLs prices are volatile. Since the second half of 2014, there has been a substantial decline in commodity prices which has significantly and negatively affected our 2015 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."

Our oil, condensate and NGLs production in the Appalachian Basin and the Mid-Continent is 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.

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 our Mid-Continent area, and all natural gas production from this region is sold on the spot market to regional pipeline companies.

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.

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The following table provides information regarding our significant customers whom accounted for more than 10% of our oil, condensate, natural gas and NGLs revenues, excluding hedge impact, for the periods indicated:

	For the Years Ended December 31,		
	2015	2014	2013
SEI	22%	50 %	56 %
Sunoco	62%	37 %	16 %

SEI and Sunoco Logistics Partners L.P. ("Sunoco") purchase the majority of the Company's 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. SEI purchases the majority of our Appalachian Basin production. There are limited oil, condensate, natural gas and NGLs purchase and transportation alternatives currently available in Appalachia. If SEI was to cease purchasing and transporting our Appalachian Basin 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 restricted. 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 oil and natural gas fluctuates seasonally. 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 (“NORM”); 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 an oil or natural gas prospect or acreage.

The regulatory burden on the oil and natural gas industry increases our cost of doing business and affects our financial condition. Historically, our compliance costs have not had a material adverse effect on our results of operations; however, we are unable to predict the future cost or impact of complying with applicable laws and regulations because those legal requirements 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 oil and natural gas 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 oil and natural gas properties; the establishment of maximum rates of production from oil and natural gas 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 oil and natural gas 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 crude oil, natural gas, condensate and NGLs 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, we would be required to annually report to FERC on May 1 of each year information regarding natural gas purchase and sale transactions if we have purchase or sale transactions that contribute or may contribute to the formation of a gas index during the prior calendar year in excess of 2.2 million MMBtu. 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. Under FERC regulations, wholesale buyers and sellers of physical natural gas are 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 in excess of 2.2 million MMBtu to the extent such transactions utilize, contribute to or may contribute to the formation of price indices.

Additional proposals and proceedings that might affect the natural gas industry are pending or 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. 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

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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.

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, tribal, 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, which may cause us to incur significant capital expenditures on costly actions to achieve and maintain compliance. These laws and regulations may, among other things, require the acquisition of permits, including drilling permits, before conducting regulated activities; restrict the types, quantities and concentrations of various substances that may 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 or result in seismic incidents; 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 sanctions, including administrative, civil and criminal penalties, the imposition of investigatory, remedial and corrective action obligations, the occurrence of delays or restrictions in permitting or performance of projects, or the issuance of injunctions limiting or prohibiting operations.

The trend in environmental legislation and regulation is toward stricter standards to place more restrictions and limitations on activities that may adversely affect the environment. While we have not been required to expend material capital expenditures or other resources in order to satisfy existing applicable environmental laws and regulations, 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 for environmental claims 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 arising from our operations may result in our being liable for material remedial costs and damages to natural resources or properties as well as the suspension or cessation of our operations in the affected area. Although we maintain insurance coverage against costs of certain clean-up operations, no assurance can be given that we have insurance or 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, as amended from time to time, to which our business operations are subject.

Hazardous Substances and Wastes

The Comprehensive Environmental Response, Compensation and Liability Act (“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 transport or 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 NGLs from the definition of hazardous substance, our operations as well as other operations in which we own a working interest generate materials that are subject to regulation as hazardous substances under CERCLA.

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The Resource Conservation and Recovery Act (“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 a working interest, generate wastes, including hazardous wastes that are subject to RCRA and comparable state laws. Although RCRA currently excludes 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 exclusion will be preserved in the future. For example, in August 2015, several non-governmental organizations filed notice of intent to sue the EPA under RCRA for, among other things, the agency’s alleged failure to reconsider whether such RCRA exclusion should continue to apply. Any removal of this exclusion, repeal or modification of this exclusion or similar exclusions 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.

Moreover, there have been public concerns expressed about NORM being detected in flow back water resulting from hydraulic fracturing, particularly in the Marcellus Shale area. NORM is subject primarily to individual state radiation control regulations while NORM handling and management activities are governed by regulations promulgated by the federal Occupational Safety and Health Administration. These state and federal regulations impose certain requirements concerning worker protection with respect to NORM as well as the treatment, storage and disposal of such flow back water generated from these activities. Concern over NORM in general, or NORM in groundwater in particular, could result in further regulation in the treatment, storage, handling and discharge of flow back water generated from oil and natural gas activities, including hydraulic fracturing, that, if implemented, could limit drilling or increase the costs of drilling in affected regions.

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 oil and natural gas. 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 (“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. Also, the EPA issued a final rule in May 2015 that attempts to clarify the federal jurisdictional reach over waters of the United States but this rule has been stayed nationwide by the U.S. Sixth Circuit Court of Appeals as that appellate court and numerous district courts ponder lawsuits opposing implementation of the rule. To the extent the rule expands the scope of the CWA's jurisdiction, we could face increased costs and delays with respect to obtaining permits for dredge and fill activities in wetland areas. 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 ("OPA") amends the CWA and sets 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.

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Our oil and natural gas exploration, development and production operations, and other operations in which we own a working 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 ("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. Historically, our SDWA compliance costs have not had a material adverse effect on our results of operations; however, future changes in the SDWA or analogous state laws or in implementing regulations, or any 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 restricted, suspended or shut down the use of such disposal wells. For example, in Oklahoma, the Oklahoma Corporation Commission ("OCC") has implemented a variety of measures including adopting the National Academy of Science's "traffic light system," pursuant to which the agency reviews new disposal well applications for proximity to faults, seismicity in the area and other factors in determining whether such wells should be permitted, permitted only with special restrictions, or not permitted and, further, evaluates existing wells to assess their continued operation, or operation with restrictions, based on location relative to such faults, seismicity and other factors, with certain of such existing wells required to make frequent, or even daily, volume and pressure reports. The OCC also has established rules requiring operators of certain saltwater disposal wells in seismically-active areas, or Areas of Interest, within the Arbuckle formation of the state to, among other things, conduct mechanical integrity testing or make certain demonstrations of such wells' depth that, depending on the depth, could require the plugging back of such wells and/or the reduction of volumes disposed in such wells. As a result of these measures, the OCC from time to time has developed and implemented plans calling for wells within Areas of Interest where seismic incidents have occurred to restrict or suspend disposal well operations in an attempt to mitigate the occurrence of such incidents. For example, only recently, in January 2016, the OCC ordered five Arbuckle disposal wells within 10 miles of the center of earthquake activity in the Edmond area of Oklahoma to reduce disposal volumes, with wells within 3.5 miles of the activity to reduce their disposal volumes by 50 percent while the other wells within 10 miles of the activity to reduce their disposal volume by 25 percent. In addition, in January 2016, the Governor of Oklahoma announced a grant of $1.38 million in emergency funds to support earthquake research, which research is to be directed by the OCC and the Oklahoma Geological Survey and, in February 2016, the OCC announced the implementation of a plan that will significantly decrease disposal volumes in approximately 245 disposals located in Western Oklahoma over a two-month period. To date, such plan has had no impact on our operations. Evaluation of seismic incidents and whether or to what extent those events are induced by the injection of saltwater into disposal wells continues to evolve, as governmental authorities consider new and/or past seismic incidents in areas where salt water disposal activities occur or are proposed to be performed. The adoption of any new laws, regulations, or directives that restrict our ability to dispose of saltwater generated by production and development activities, whether by plugging back the depths of disposal wells, reducing the volume of salt water disposed in such wells, restricting disposal well locations or otherwise, or by requiring us to shut down disposal wells, could have a material adverse effect on our business, financial condition and results of operations.

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 issued Clean Air Act (“CAA”) final regulations in 2012 and proposed additional CAA regulations in August 2015 governing performance standards for the oil and natural gas industry; proposed in April 2015 effluent limitations guidelines that waste water from shale natural gas extraction operations must meet before discharging to a treatment plant; and issued in 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”) published a final rule in March 2015 that establishes new or more stringent standards for performing hydraulic fracturing on federal and Indian lands but, in September 2015, the U.S. District Court of Wyoming issued a preliminary injunction barring implementation of this rule, which order the BLM could appeal and is being separately appealed by certain environmental groups.

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, Pennsylvania 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 high volume hydraulic fracturing altogether, following the approach taken by the State of New York in 2015. 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 released its draft report on the potential impacts of hydraulic fracturing on drinking water resources in June 2015, which report concluded that hydraulic fracturing activities have not led to widespread, systemic impacts on drinking water sources in the United States, although there are above and below ground mechanisms by which hydraulic fracturing activities have the potential to impact drinking water sources. However, in January 2016, the EPA's Science Advisory Board provided its comments on the draft study, indicating its concern that EPA's conclusion of no widespread, systemic impacts on drinking water sources arising from fracturing activities did not reflect the uncertainties and data limitations associated with such impacts, as described in the body of the draft report. The final version of this EPA report remains pending and is expected to be completed in 2016. Such EPA final report, when issued, as well as 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 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. Any need to obtain air emissions permits has the potential to delay the development of oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, in October 2015, the EPA issued a final rule lowering the National Ambient Air Quality Standard ("NAAQS") for ground-level ozone to 70 parts per billion for the 8-hour primary and secondary ozone standards. The EPA is required to make attainment and non-attainment designations for specific geographic locations under the revised standards by October 1, 2017. With EPA lowering the ground-level ozone standard, states may be required to implement more stringent regulations, which could apply to our operations and require the installation of , resulting in a need to install new emissions controls, longer permitting timelines and significant increases in our capital or operating expenditures, 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,

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among others, onshore and offshore oil and natural gas production facilities, which include certain of our operations. We monitor and report on GHG emissions from our operations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions to acquire and surrender emission allowances in return for emitting those GHGs. The adoption of any legislation or regulations that require reporting of GHGs or otherwise limits emissions of GHGs from our equipment and operations could cause us to incur costs to purchase and operate emissions control systems, acquire emissions allowance or comply with new regulatory or reporting requirements including the imposition of a carbon tax, which costs could be significant. For example, in August 2015, the EPA announced proposed rules, expected to be finalized in 2016, that would establish new controls for methane emissions from certain new, modified or reconstructed equipment and processes in the oil and natural gas source category, including production activities, as part of an overall effort to reduce methane emissions by up to 45 percent in 2025. On an international level, the United States is one of almost 200 nations that agreed in December 2015 to an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets. It is not possible at this time to predict how or when the United State might impose restrictions on GHGs as a result of the international agreement agreed to in Paris. Any such legislation or regulatory programs could also increase the cost to the consumer, and thereby reduce demand for oil and natural gas, which could reduce demand for the oil and natural gas we produce.

Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth’s atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, 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 (“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. Some of our operations may be located in or near areas that are designated as habitat for endangered or threatened species and, in these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts to protected species or be prohibited from conducting operations 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 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, on September 1, 2015, the U.S. District Court for the Western District of Texas vacated the FWS’ rule listing the lesser prairie chicken in its entirety, concluding that the decision to list the species was arbitrary and capricious. Whether the lesser prairie chicken or other species will be listed in the future under the ESA is currently unknown but 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 (“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.

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. The NEPA review process may take a significant amount of time and is subject to challenges by environmental groups, which have the potential to delay current and future projects. 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 currently planning any drilling operations on BLM leased acreage in 2016. 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 NORM. 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 6. “Selected Financial Data” and Item 8. ‘‘Financial Statements and Supplementary Data,” each 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 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. 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

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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 7, 2016, we had 51 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.

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.

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Oil, condensate, natural gas and NGLs prices are volatile. Since the second half of 2014, there has been a substantial decline in commodity prices which has significantly and negatively affected our financial condition and results of operations.

The success of our business depends primarily on the market prices of oil, condensate, natural gas and NGLs. Oil, condensate, natural gas and NGLs prices are set by broad market forces, which have been and will likely continue to be volatile in the future. Since the second half of 2014, commodity prices have declined precipitously as a result of several factors, including increased worldwide supplies, a stronger U.S. dollar, weather factors, a strong competition among oil producing countries for market share and decreased demand in emerging markets, such as China. Specifically, WTI prices have declined from a monthly average of $101.68 per barrel in June 2014 to a monthly average of $27.08 per barrel in February 2016. 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 $1.97 per MMBtu in February 2016. These depressed commodity prices adversely affected our 2015 financial condition and results of operations and contributed to a reduction in our anticipated future capital expenditures. In addition, this decline in commodity prices has adversely impacted our estimated proved reserves and resulted in substantial impairments to our oil and natural gas properties during 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 effects 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;
- 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 cash 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 2015, approximately 83% and 17% 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 $46.18 and $16.78, respectively, excluding the impact of hedging activities for the year. This compares to the daily unweighted average WTI posted price of $45.35 per barrel for 2015. Price differentials are most acute within our Appalachian Basin markets for natural gas and NGLs. For the year ended December 31, 2015, our realized NGLs prices for Marcellus Shale and Mid-Continent NGLs production represented approximately 4% and 29%, respectively, of the full-year 2015 daily unweighted average WTI posted price of $45.35, excluding the impact of hedging activities for the year. During 2015, 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, 2015, the Henry Hub spot price was $2.27 per MMBtu, compared to the TETCO M2 basis point pricing of $1.28 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. For the year ended December 31, 2015, our realized natural gas prices for Appalachian Basin and Mid-Continent production excluding the impact of hedging activities represented approximately 30% and 98%, respectively, of the full-year 2015 daily unweighted average Henry Hub posted price of $2.61.

We are highly leveraged and 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 such agreements, which may not be successful, or if successful, could be highly dilutive to existing holders of our common and preferred stock.

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 our $325.0 million outstanding principal amount of 8 5/8% Senior Secured Notes due 2018 (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, as well as our ability to complete pending and proposed asset sales. As of March 9, 2016, our cash balance was approximately $28.8 million. 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.

Our level of indebtedness will have several important effects on our future operations, including, without limitation:

- requiring us to dedicate a significant portion of our cash flows from operations to support the payment of debt service;
- increasing our vulnerability to adverse changes in general economic and industry conditions, and putting us at a competitive disadvantage relative to competitors that have fewer fixed obligations and greater cash flows to devote to their businesses;
- limiting our ability to obtain additional financing for working capital, capital expenditures, general corporate and other purposes; and
- limiting our flexibility in operating our business and preventing us from engaging in certain transactions that might otherwise be beneficial to us.

Due to the relatively high level of our indebtedness, we are pursuing or analyzing various alternatives to reduce the level of our long-term debt and lower our future debt obligations, including the application of proceeds from targeted assets sales disclosed elsewhere in this report, followed by possible debt repurchases, exchanges of existing debt securities for new debt securities and exchanges or conversions of existing debt securities for new equity securities, among other options. Our ability to restructure or refinance our indebtedness will depend on the condition of the capital markets and our financial condition at such time. One or more of these alternatives could potentially be consummated with the consent of any one or more of our current security holders, or, if necessary, without the consent of holders through a restructuring under a voluntary bankruptcy proceeding. 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 including required reduction in amounts owed in our Revolving Credit Facility as a result of reductions in our borrowing base. If we are unable to meet our debt obligations, we would be forced to restructure our indebtedness and equity capitalization. Depending upon asset values and other factors, any future restructuring could be highly dilutive to existing holders of our common and preferred stock, could result in equity holders losing a significant amount or all of their investment in us and may adversely affect the trading prices and values of our existing debt and equity securities.

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The borrowing base under our Revolving Credit Facility was recently reduced to $180.0 million, and as of March 9, 2016, there was $180.0 million in borrowings outstanding under the Revolving Credit Facility. Upon the earlier to occur of the closing of the Appalachian Basin Sale or April 10, 2016, the borrowing base will be automatically reduced to $100.0 million and require borrowings in excess of such amount to be immediately repaid. We expect that proceeds from the Appalachian Basin Sale will be approximately $80.0 million and will be used to reduce borrowings outstanding under our Revolving Credit Facility to achieve compliance with the reduction of the borrowing base. In connection with Amendment No. 8 (as defined and described below) to the Revolving Credit Facility, we have agreed to an additional scheduled borrowing base redetermination in August 2016. Our borrowing base is otherwise determined semi-annually by our lenders in May and November of each year and is based on our proved reserves and the value attributed to those reserves. We and the lenders each have the option to initiate a redetermination of the borrowing base between scheduled semi-annual redeterminations.

The borrowing base under our Revolving Credit Facility could be further reduced as a result of lower oil or natural gas prices, declines in estimated oil and natural gas reserves or production, our issuance of new indebtedness or for other reasons. If the borrowing base under our Revolving Credit Facility is further reduced, there would be a reduction of our available credit and the potential requirement for us to repay outstanding indebtedness in excess of the redetermined borrowing base. In addition, we may not be able to access adequate funding under our Revolving Credit Facility as a result of the 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. If our borrowing base is further reduced or we cannot access adequate funding under our Revolving Credit Facility, it will reduce the availability of our cash flow for replacing reserves through implementing our drilling and development plan, making acquisitions or otherwise carrying 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.

The Appalachian Basin Sale may not be completed, and we may not receive the consideration expected from such sale to make the required debt reduction payments on a timely basis.

The Appalachian Basin Sale is expected to close on or before March 31, 2016, with an effective date of January 1, 2016, subject to customary closing conditions, including obtaining certain required lessor consents to assign. If these conditions are not satisfied or waived, the Appalachian Basin Sale may not be consummated. There can be no assurances that the Appalachian Basin Sale will be consummated or that we will receive the consideration expected from such sale. As of March 9, 2016, our cash balance was approximately $28.8 million. If the Appalachian Basin Sale is delayed, not consummated or consummated in a manner different than expected, we may not have sufficient cash on hand to fund borrowings in excess of the borrowing base under our Revolving Credit Facility, which is currently scheduled to require repayments to reduce outstanding borrowings to $100.0 million by April 10, 2016. See "—We are highly leveraged and 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 such agreements, which may not be successful, or if successful, could be highly dilutive to existing holders of our common and preferred stock."

Recent amendments to our Revolving Credit Facility prohibit us from paying cash dividends after March 2016 on our outstanding preferred stock and we may not be able to pay such dividends in the future.

Effective March 9, 2016, our Revolving Credit Facility was amended to, among other things, prohibits the payment of cash dividends on our preferred stock commencing April 2016. There is no assurance when or if we will be able to pay cash dividends, including accumulated and unpaid dividends, on our outstanding two series of preferred stock in the future. We may in the future, in lieu of cash dividends, elect to pay accumulated and unpaid dividends on our outstanding preferred stock by issuing shares of our common stock, as provided in the certificates of designation of rights and preferences setting forth the terms of our outstanding Series A Preferred Stock and Series B Preferred Stock, which issuance will dilute our existing common shareholders. If we fail to pay full cash dividends in four quarters, whether consecutive or non-consecutive, then holders of our outstanding Series A and Series B Preferred Stock, voting as a single class, will also have the right to elect up to two directors to the board of directors of the Company.

Our development operations will require substantial capital expenditures in order to grow or maintain our production levels. Our limited access to the funds for necessary future growth and maintenance capital expenditures could have a material adverse effect on our business, results of operations, financial condition and ability to pay cash dividends to our preferred stockholders and to make required payments on our indebtedness.

The oil and natural gas industry is capital intensive. While we expect to make limited capital expenditures in 2016 in order to preserve liquidity while commodity prices are depressed, in the future, we expect to make substantial growth and maintenance capital expenditures in our business for the development, production and acquisition of oil and natural gas reserves. These expenditures

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reduce the amount of cash available for distribution to our preferred stockholders and to service our indebtedness. Our preliminary capital budget for 2016 totals approximately $37.0 million, excluding capitalized costs, which we expect to fund these expenditures using existing cash balances, cash generated internally from our operations and the possible divestiture of assets 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.

In the current oil and natural gas price environment, our sources of capital are constrained. Our failure to obtain the funds for capital expenditures could have a material adverse effect on our business, results of operations, financial condition and ability to pay cash dividends 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 be highly dilutive to our equity or be available only at significantly higher interest rates. These funds, if available, may limit or prohibit paying cash dividends to our preferred stockholders and to service our indebtedness. In addition, incurring additional debt will increase our already significant financial leverage. Recent amendments to our Revolving Credit Facility also prohibit us from paying cash dividends on our outstanding shares of Series A and Series B Preferred Stock commencing in April 2016.

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 Energy Corporation 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, exploit or maintain our oil and natural gas 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.

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 697,000 Bbls of crude production, 8.9 Bcf of natural gas production and 183,000 Bbls of NGLs production in 2016, 519,000 Bbls of crude production and 7.3 Bcf of natural gas production in 2017, and 103,000 Bbls of crude production and 3.7 Bcf of natural gas production in 2018 as of December 31, 2015. 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 Mid-Continent or 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.

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Approximately 83% of our oil, condensate, natural gas and NGLs revenues, before the impact of hedges, and approximately 73% of our total proved reserves for the year ended December 31, 2015 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 or governmental actions limiting or shutting-in production.

Approximately 17% of our oil, condensate, natural gas and NGLs revenues before the impact of hedges and approximately 27% of our total proved reserves for the year ended December 31, 2015 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. On February 19, 2016, we entered into an agreement to sell substantially all of our assets and proved reserves and a significant portion of our undeveloped acreage in the Appalachian Basin for $80.0 million, subject to certain adjustments and customary closing conditions, including obtaining certain required lessor consents to assign. The transaction is expected to close on or before March 31, 2016. If the Appalachian Basin Sale does not occur, we will remain exposed to these disruption risks.

Following the expected completion of our Appalachian Basin Sale, our producing properties will be concentrated in the Mid-Continent, making us vulnerable to risks associated with operating in one major geographic area.

Following the expected completion of our Appalachian Basin Sale, our producing properties and all of our proved reserves will be geographically concentrated in the Mid-Continent, with a particular concentration in Oklahoma. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in these areas caused by and costs associate with governmental regulation, processing or transportation capacity constraints, market limitations, water shortages or other weather related conditions or interruption of the processing or transportation of oil, condensate, natural gas or NGLs and changes in regional and local political regimes and regulations. Such conditions could have a material adverse effect on our financial condition and results of operations.

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, 2015, SEI accounted for substantially all of our revenues from the Appalachian Basin. 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.

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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 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 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 49% of our proved reserves are classified as proved undeveloped at December 31, 2015 and may ultimately prove to be less than current reserves estimates.

At December 31, 2015, approximately 49% of our total proved reserves were classified as proved undeveloped and all were located in the Mid-Continent. It will take approximately $353.8 million of capital to drill our undeveloped locations over the next five years. Our estimate of proved reserves at December 31, 2015 assumes that we will spend in 2016 and 2017 development capital expenditures to develop these reserves of $1.8 million and $66.7 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 since the middle of 2014 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, 2015 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

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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 NORM 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;
- Adverse weather conditions;
- Compliance with existing and any future governmental laws and regulations, including environmental requirements; 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.

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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 2011 to 2015 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, 2015 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 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 continue to 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 continuing throughout 2015 into 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, 2015 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 benchmark 12-month average price applicable to first quarter 2016 proved reserves under SEC rules decreased to $46.26 per barrel for crude oil and $2.40 per Mcf for natural gas. If such pricing was used in applying the Company's December 31, 2015 ceiling test for impairment, the Company estimates its impairment charge for the quarter ended December 31, 2015 would have increased by approximately $52.0 million.

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, 2015, 82 gross (8.9 net) wells in which we have an interest were operated by other companies.

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 Notes and the documentation governing our 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

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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.”

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, tribal, 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 obtained or obtained in a timely manner. 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.

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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, remedial or corrective action obligations, the occurrence of delays or restrictions in permitting or the performance of projects, and the issuance of orders enjoining or limiting some or all of our operations in affected areas, 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 October 2015, the EPA issued a final rule lowering the NAAQS for ozone to 70 parts per billion 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.

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 issued CAA final regulations in 2012 and proposed additional CAA regulations in August 2015 governing performance standards for the oil and natural gas industry, including standards for the capture of air emissions released during hydraulic fracturing; proposed in April 2015 effluent limitation guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and issued in 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 published a final rule in March 2015 that establishes new or more stringent standards for performing hydraulic fracturing on federal and Indian lands, but, in September 2015, the U.S. District Court of Wyoming issued a preliminary injunction barring implementation of this rule, which order the BLM could appeal and is being separately appealed by certain environmental groups.

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 high volume hydraulic fracturing altogether, following the approach taken by the State of New York in 2015. 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 released its draft report on the potential impacts of hydraulic fracturing on drinking water resources in June 2015, which report concluded that hydraulic fracturing activities have not led to widespread, systemic impacts on drinking water sources in the United States, although there are above and below ground mechanisms by which hydraulic fracturing activities have the potential to impact drinking water sources. However, in January 2016, the EPA's Science Advisory Board provided its comments on the draft study, indicating its concern that the EPA's conclusion of no widespread, systemic impacts on drinking water sources arising from fracturing activities did not reflect the uncertainties and data limitations associated with such impacts, as described in the body of the draft report. The final version of this EPA report remains pending and is expected to be completed in 2016. Such EPA final report, when issued, as well as 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.

We may incur 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 significant delays or restrictions in acquisition of permits or performance of projects, or 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;
- 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 or cancellation 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 or properties. 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.

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Future legislation may result in the elimination of certain U.S. federal income tax deductions currently available with respect to oil and natural gas exploration and development. Additionally, future federal or state legislation may impose new or increased taxes or fees on oil and natural gas extraction.

Potential legislation, if enacted into law, could make significant changes to U.S. federal and state income tax laws, including the elimination of certain key U.S. federal income tax incentives 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 natural gas properties; (ii) the elimination of current deductions for intangible drilling and development costs; (iii) the elimination of the deduction for certain U.S. production activities; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear whether these or similar changes will be enacted and, if enacted, how soon any such changes could become effective. The passage of this legislation or any other similar changes in U.S. federal and state income tax laws could eliminate or postpone certain tax deductions that are currently available with respect to oil and natural gas exploration and development, and any such change could negatively impact the value of an investment in our common stock. Additionally, legislation could be enacted that increases the taxes states impose on oil and natural gas extraction. Moreover, President Obama has proposed, as part of the Budget of the United States Government for Fiscal Year 2017, to impose an "oil fee" of $10.25 on a per barrel equivalent of crude oil. This fee would be collected on domestically produced and imported petroleum products. The fee would be phased in evenly over five years, beginning October 1, 2016. The adoption of this, or similar proposals, could result in increased operating costs and/or reduced consumer demand for petroleum products, which in turn could affect the prices we receive for our oil.

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, in part, 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 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 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. Although we expect to qualify for the end-user exception to such 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. In addition, certain banking regulators and the CFTC have recently adopted final rules establishing minimum margin requirements for un-cleared swaps. Although we expect to qualify for the end-user exception from such 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. If any of our swaps do not qualify for the commercial end-user exception, posting of collateral could impact liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flow.

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 August 2015, the EPA announced proposed rules, expected to be finalized in 2016, that would establish new controls for methane emissions from certain new, modified or reconstructed equipment and processes in the oil and natural gas source category, including production activities, as part of an overall effort to reduce methane emissions by up to 45 percent in 2025. On an international level, the United States is one of almost 200 nations that agreed in December 2015 to an international climate change agreement in Paris, France that calls for countries to set their own GHG emissions targets and be transparent about the measures each country will use to achieve its GHG emissions targets. It is not possible at this time to predict how or when the United States might impose restrictions on GHGs as a result of the international agreement agreed to in Paris. Any such legislation or regulatory programs could also increase the cost to the consumer, and thereby reduce demand for oil and natural gas, which could reduce demand for the oil and natural gas we produce.

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

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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 certificate of incorporation authorizes 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.
- On February 19, 2016, we entered into an agreement to sell substantially all of our assets and proved reserves and a significant portion of our undeveloped acreage in the Appalachian Basin for $80.0 million, subject to certain adjustments and customary closing conditions, including obtaining required lessor consents to assign. The transaction is expected to close on or before March 31, 2016 with an effective date of January 1, 2016.

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.

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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,		
	2015	2014	2013
Production:			
Oil and condensate (MBbl)	1,425	975	515
Natural gas (MMcf)	13,759	11,598	13,366
NGLs (MBbl)	1,213	801	494
Total production (MBoe)	4,931	3,708	3,236
Daily Production:			
Oil and condensate (MBbl/d)	3.9	2.7	1.4
Natural gas (MMcf/d)	37.7	31.8	36.6
NGLs (MBbl/d)	3.3	2.2	1.4
Total daily production (MBoe/d)	13.5	10.2	8.9
Average sales price per unit(1):			
Oil and condensate per Bbl, excluding impact of hedging activities	$41.17	$84.98	$70.91
Oil and condensate per Bbl, including impact of hedging activities(2)	$46.86	$83.86	$71.04
Natural gas per Mcf, excluding impact of hedging activities	$1.23	$4.11	$3.02
Natural gas per Mcf, including impact of hedging activities(2)	$1.81	$3.84	$3.43
NGLs per Bbl, excluding impact of hedging activities	$5.89	$26.71	$31.59
NGLs per Bbl, including impact of hedging activities(2)	$14.42	$26.53	$31.13
Average sales price per Boe, excluding impact of hedging activities	$16.77	$40.95	$28.58
Average sales price per Boe, including impact of hedging activities(2)	$22.14	$39.78	$30.20
Selected operating expenses (in thousands):			
Production taxes(3)	$2,877	$6,733	$4,651
Lease operating expenses(3)	$23,728	$19,323	$9,456
Transportation, treating and gathering(3)	$2,187	$3,679	$4,006
Depreciation, depletion and amortization	$62,887	$46,180	$32,449
Impairment of natural gas and oil properties	$426,878	$—	$—
General and administrative expense	$17,069	$16,485	$16,961
Selected operating expenses per Boe:			
Production taxes(3)	$0.58	$1.82	$1.44
Lease operating expenses(3)	$4.81	$5.21	$2.92
Transportation, treating and gathering(3)	$0.44	$0.99	$1.24
Depreciation, depletion and amortization	$12.75	$12.45	$10.02
General and administrative expense(4)	$3.46	$4.45	$5.24
Production costs(5)	$4.98	$6.00	$4.05

(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

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(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, employee severance and corporate migration of $1.4 million, $263,000 and $4.2 million for the years ended December 31, 2015, 2014 and 2013, respectively. Excluding such costs, general and administrative expenses per Boe would have been $3.18, $4.37 and $3.95 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

Drilling Activity

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

	For the Years Ended December 31,					
	2015		2014		2013	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Productive	24.0	15.0	30.0	14.9	11.0	5.7
Non-productive	—	—	—	—	—	—
Total	24.0	15.0	30.0	14.9	11.0	5.7
Development wells:						

Productive	15.0	11.4	11.0	6.0	17.0	8.5
Non-productive	—	—	—	—	—	—
Total	15.0	11.4	11.0	6.0	17.0	8.5

On December 31, 2015, we were participating in five gross (0.5 net) non-operated wells in the process of being drilled in the Mid-Continent.

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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, 2015.

	Undeveloped Acreage		Developed Acreage	
	Gross	Net	Gross	Net
Appalachian Basin, West Virginia and Pennsylvania(1)(2)				
Marcellus West(3)(4)	17,612	6,796	9,916	4,704
Marcellus East	25,925	22,921	2,873	2,509
Total Appalachian Basin	43,537	29,717	12,789	7,213
Mid-Continent	113,471	60,281	71,434	50,439
Total	157,009	89,998	84,223	57,652

(1) On February 19, 2016, we entered into an agreement to sell substantially all of our assets and proved reserves and a significant portion of our undeveloped acreage in the Appalachian Basin for $80.0 million, subject to certain adjustments and customary closing conditions, including obtaining certain required lessor consents to assign. The transaction is expected to close on or before March 31, 2016 with an effective date of January 1, 2016.
(2) We believe that substantially all of our Appalachian Basin acreage is prospective.
(3) The Marcellus West acreage reflects that Atinum has earned their full participation interest.
(4) Approximately 25,600 gross (10,300 net) acres of our Marcellus West acreage 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 as of December 31, 2015, our gross undeveloped acreage scheduled to expire.

	Appalachian Basin			Total Expiring	% of Total Undeveloped	
	West	East	Mid-Continent	Gross Acres	Gross Acres	
2016	2,222	13,429	50,603	66,254	42	%
2017	4,420	52	49,304	53,776	34	%
2018	4,819	7	13,522	18,348	12	%
2019	2,249	—	42	2,291	1	%
2020 and thereafter	2,535	—	—	2,535	2	%

The table below summarizes, by year as of December 31, 2015, our net undeveloped acreage scheduled to expire.

	Appalachian Basin			Total Expiring	% of Total Undeveloped
	West	East	Mid-Continent	Net Acres	Net Acres
2016	1,107	10,945	22,862	34,914	39 %
2017	1,372	52	29,452	30,876	34 %
2018	1,571	7	7,871	9,449	10 %
2019	938	—	69	1,007	1 %
2020 and thereafter	1,163	—	27	1,190	1 %

We have lease acreage that is generally subject to lease expiration if initial wells are not drilled within a specified period, generally not exceeding three to five years. As is customary in the oil and natural gas industry, we can retain our interest in undeveloped acreage by commencing drilling activity that establishes commercial production sufficient to maintain the leases or by payment of delay rentals during the primary term of such leases. We do not assign proved undeveloped reserves to leases after their expiration. Of the approximately 34,900 net undeveloped acres expiring in 2016, we are currently focusing on net acres expiring in the Mid-Continent. In the Mid-Continent, approximately 4,300 net acres, or 19%, expiring during 2016 have automatic lease extension provisions allowing us to extend the lease for an additional two-year term by payment of lease bonus ranging from $450 to $1,000 per net acre. We plan to make the majority of the automatic lease extension payments. We also plan to extend the leases for any additional acreage expiring during 2016 in the Mid-Continent that do not have automatic lease extensions that we have determined to be in areas that are the focus of our future drilling operations. If we are not able to extend the lease, the acreage will expire. We may in the future,

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sell Mid-Continent acreage that we deem to be non-strategic. Our current plans in Marcellus East are to let the approximately 10,900 net undeveloped acres scheduled for expiration in 2016 expire.

Productive Wells

The following table sets forth our working interest ownership in productive wells in the areas indicated as of December 31, 2015. The term "gross" represents the total number of wells in which we own a working interest. The term "net" represents our proportionate working interest resulting from our ownership in gross wells. Productive wells are wells that are currently capable of producing oil or natural gas. Wells that are completed in more than one producing horizon are counted as one well.

	Productive Wells					
	Natural Gas		Oil		Total Wells	
	Gross	Net	Gross	Net	Gross	Net
Appalachian Basin, West Virginia and Pennsylvania[1]	116.0	55.6	—	—	116.0	55.6
Mid-Continent, Oklahoma	183.0	97.8	54.0	44.4	237.0	142.2
Total	299.0	153.4	54.0	44.4	353.0	197.8

(1) On February 19, 2016, we entered into an agreement to sell substantially all of our assets and proved reserves and a significant portion of our undeveloped acreage in the Appalachian Basin for $80.0 million, subject to certain adjustments and customary closing conditions, including obtaining certain required lessor consents to assign. The transaction is expected to close on or before March 31, 2016 with an effective date of January 1, 2016. Subsequent to the closing of the transaction, we will own 18 gross (14.7 net) productive natural gas wells in the Appalachian Basin.

Oil and Natural Gas Reserves

Reserve Estimation

The SEC rules expand the definition of oil and natural gas producing activities to include the extraction of saleable hydrocarbons from oil sands, shale, coal beds or other nonrenewable natural resources that are intended to be upgraded into synthetic natural gas or oil and activities undertaken with a view to such extraction. The use of new technologies is now permitted in the determination of proved reserves if those technologies have been demonstrated empirically to lead to reliable conclusions about reserve volumes. Proved reserves must be estimated using the unweighted average of first-day-of-the-month commodity prices over the preceding 12-month period, rather than the end-of-period price, when estimating whether reserve quantities are economical to produce. Likewise, the unweighted 12-month average price is used to compute depreciation, depletion and amortization and in the application of the "ceiling test" for determining impairment of oil and natural gas properties under full cost accounting. The unweighted 12-month average commodity prices used in determining December 31, 2015 estimates of proved reserves and related PV-10 and standardized measure of future net cash flows are substantially above current oil and natural gas prices. Subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking.

Third Party Review of Reserves Estimates

For the years ended December 31, 2015, 2014 and 2013, reserves estimates for the Appalachian Basin and Mid-Continent area shown herein have been independently evaluated by Wright & Company, Inc. ("Wright"), a national firm providing petroleum property analysis for industry and financial organizations with extensive experience in both of our operating areas. Wright was founded in 1988 and performs consulting petroleum engineering services. A copy of Wright's summary reserve report is included as Exhibit 99.1 to this Form 10-K. Within Wright, the technical person primarily responsible for preparing the reserves estimates set forth in the Wright reserve report incorporated herein is Mr. D. Randall Wright. Mr. Wright has been practicing consulting petroleum engineering at Wright since 1988, the year in which he founded the company. He is a Registered Professional Engineer in the State of Texas and has over 40 years of practical experience in petroleum engineering and in the estimation and evaluation of reserves. He has a Master of Science degree in Mechanical Engineering from Tennessee Technological University. The technical principal meets or exceeds the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserves definitions and guidelines.

Qualifications of Technical Persons and Internal Controls Over Reserves Estimates

The preparation of our reserve estimates are completed in accordance with our prescribed internal control procedures and are subject to management review. We maintain an internal technical team consisting of our Senior Reservoir Engineer and several geoscience professionals, who work closely with Wright to ensure the integrity, accuracy and timeliness of data furnished to Wright in their reserve review and estimation process. Throughout the year, our internal technical team meets regularly with representatives of Wright to review properties and discuss methods and assumptions used in Wright's preparation of the year-end reserves estimates. We provide historical information to Wright for our largest producing properties, including ownership interest, oil and natural gas production, well test data, commodity prices and operating and development costs. Wright performs an independent analysis, and differences are reviewed with our senior management. In some cases, additional meetings are held to review additional reserve work performed by our technical team related to any identified reserve differences. Historical variances between our internal reserves estimates and Wright's estimates have historically been less than 5%. In addition, our Board of Directors has a reserves review committee, which is chaired by an independent director. The reserves review committee meets at least once a year and is specifically designated to review the year-end reserves reporting and the reserves estimation process, while our senior management reviews and approves any internally estimated significant changes to our proved reserves on a quarterly basis. The year-end Wright reserves report is reviewed by the reserves review committee, together with representatives of Wright and our internal production and engineering team.

Since 2006, all of our reserves estimates have been reviewed and approved by our Senior Reservoir Engineer, who reports directly to our Chief Financial Officer. Our Senior Reservoir Engineer attended Texas A&M University and graduated in 1978 with a Bachelor of Science degree in Reservoir Engineering and has been involved in evaluations and the estimation of reserves and resources for over 30 years. During the year, our technical team may also perform separate, detailed technical reviews of reserve estimates for significant acquisitions or for properties with problematic indicators such as excessively long lives, sudden changes in performance or changes in economic or operational conditions.

Technologies Used in Reserves Estimation

Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from a given date forward, from known reservoirs, and under existing economic conditions, operating methods and government regulations. The term “reasonable certainty” implies a high degree of confidence that the quantities of oil and/or natural gas actually recovered will equal or exceed the estimate. The SEC allows the use of techniques that have been proven effective by actual production from projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology that establishes reasonable certainty. Reliable technology is a grouping of one or more technologies (including computational methods) that have been field tested and have been demonstrated to provide reasonably certain results with consistency and repeatability in the formation being evaluated or in an analogous formation. To achieve reasonable certainty, our technical team employs technologies that have been demonstrated to yield results with consistency and repeatability. The technologies and economic data used in the estimation of our proved reserves include, but are not limited to, empirical evidence through drilling results and well performance, well logs, geologic maps and available downhole and production data, seismic data, well test data and reservoir simulation modeling.

Estimated Proved Reserves

Our proved reserves information as of December 31, 2015 included in this Form 10-K was estimated by Wright using standard engineering and geosciences procedures and methods used in the petroleum industry. The technical personnel responsible for preparing the reserve estimates at Wright meet the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers.

In accordance with SEC regulations, estimates of our proved reserves and future net revenues as of December 31, 2015 were made using benchmark prices that are the 12-month unweighted arithmetic average of the first-day-of-the-month price for natural gas and oil ("SEC pricing"). Key benchmark base prices utilized were the Henry Hub price of $2.59 per MMBtu for natural gas and a WTI spot oil price of $50.28 per barrel. These prices are held constant in accordance with SEC guidelines for the life of the wells included in the reserve reports but are adjusted by lease in accordance with sales contracts and for energy content, quality, transportation, compression and gathering fees and regional price differentials. Estimated quantities of proved reserves and future net revenues are affected by oil and natural gas prices, which are highly volatile. Oil and natural gas prices continue to decline into 2016 and the current 12-month unweighted arithmetic average of the first-day-of-the-month prices as of March 1, 2016 are 8% and 7% lower than the SEC Pricing used as of December 31, 2015 for oil and natural gas, respectively. All of our proved reserves are located onshore within the U.S.

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The following table summarizes our estimated proved reserves as of December 31, 2015:

	Total Proved Reserves			
	Producing	Non-producing	Undeveloped	Total
Oil and condensate (MBbls)	7,181	—	17,022	24,203
Natural gas (MMcf)	77,966	—	30,485	108,451
NGLs (MBbls)	8,240	—	5,359	13,599
Total proved reserves (MBoe)	28,415	—	27,462	55,877
PV-10 (in thousands)(1)	$155,980	$ (1,184)	$ 75,007	$229,803
Standardized measure of discounted future net cash flows(1)				$229,803

(1) PV-10 represents the present value, discounted at 10% per annum, of estimated future net revenue before income tax of our estimated proved reserves. PV-10 is a non-U.S. GAAP financial measure because it excludes the effects of income taxes. We believe that PV-10 is a useful measure for evaluating the relative monetary significance of our oil and natural gas properties. Further, investors may use the measure as a basis for comparison of the relative size and value of our reserves to other companies. PV-10 should not be considered as an alternative to standardized measure of discounted future net cash flows as defined under U.S. GAAP. At December 31, 2015, we presently have approximately $512.0 million of net operating loss carryforwards, $50.7 million of foreign tax credit carryforwards and $365.3 million of remaining property tax basis for Federal income tax purposes. Based on these carryforwards and current and future property tax basis, we will not incur future income taxes, and as such, the standardized measure of discounted future net cash flows is $229.8 million as of December 31, 2015.

The following table summarizes our proved reserves by geographic area as of December 31, 2015:

SEC Pricing Case Proved Reserves(1)

	Oil and Condensate (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	MBoe	% Proved Developed	PV-10	Standardized Measure of Discounted Future Net Cash Flows
						(in thousands)	
Mid-Continent	23,219	54,829	8,700	41,057	33 %	$215,282	
Appalachian Basin, West Virginia and Pennsylvania(2)	984	53,622	4,899	14,820	100 %	14,521	
Total	24,203	108,451	13,599	55,877	51 %	$229,803	$ 229,803

(1) Key benchmark base prices utilized were the Henry Hub price of $2.59 per MMBtu for natural gas and a WTI spot oil price of $50.28 per barrel.

(2) On February 19, 2016, we entered into an agreement to sell substantially all of our assets and proved reserves and a significant portion of our undeveloped acreage in the Appalachian Basin for $80.0 million, subject to certain adjustments and customary closing conditions, including obtaining certain required lessor consents to assign. The transaction is expected to close on or before March 31, 2016, with an effective date of January 1, 2016.

Proved Undeveloped Reserves

As of December 31, 2015, our PUDs totaled 27.5 MMBoe all of which were associated with the Mid-Continent, representing a 58% decrease from our PUDs as of December 31, 2014. The December 31, 2015 PUDs consisted of 117 gross (87.4 net) wells in the Mid-Continent. The decrease in PUD well locations during 2015 is due to the suspension of the Marcellus and Utica Shale drilling programs in 2015 coupled with low prices resulting in 36.8 MMBoe of downward revisions and 7.9 MMBoe of 2014 PUD reserves that we converted to proved developed reserves in 2015 through the completion of seven gross (3.5 net) Marcellus Shale wells, one gross (0.5 net) Utica Shale well and 10 gross (8.8 net) Mid-Continent wells partially offset by 2.0 MMBoe of positive revisions and 4.8 MMBoe of extensions and discoveries in the Mid-Continent. The net cost of converting such PUDs to proved developed reserves during 2015 was $11.3 million.

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The following table summarizes our PUD activity during the year ended December 31, 2015:

	Oil and Condensate (MBbls)	Natural Gas (MMcf)	NGLs (MBbls)	MBoe
PUDs as of December 31, 2014	21,668	172,441	14,866	65,274
Extensions and discoveries	2,701	6,425	1,058	4,830
Purchases of reserves in place	855	3,006	551	1,907
PUDs converted to proved developed	(2,425)	(23,154)	(1,640)	(7,924)
Revisions of previous estimates	(5,777)	(128,232)	(9,476)	(36,625)
PUDs as of December 31, 2015	17,022	30,486	5,359	27,462

Estimated future development costs relating to the development of 2015 year-end PUDs is $350.4 million, of which 2016 and 2017 expenditures are $1.8 million and $66.5 million, respectively, which includes the drilling of no PUD locations in 2016 and 24 gross (17.2 net) PUD locations in 2017. Under current SEC requirements, PUD reserves may only be booked if they relate to wells scheduled to be drilled within five years of the original date of booking unless specific circumstances justify a longer time. All of our PUDs at December 31, 2015 are scheduled to be drilled by 2020, which is within five years from the date initially recorded as PUD reserves. We may be required to remove our PUD reserves if we do not drill those reserves within the required five-year time frame or if the PUD reserves do not remain economically producible under lower SEC prices. 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 or elimination of some of our proved undeveloped reserves.

Item 3. Legal Proceedings

Information about our legal proceedings is set forth in Item 8. “Financial Statements and Supplementary Data, Note 14, Commitments and Contingencies – Litigation” of this Form 10-K.

Item 4. Mine Safety Disclosures.

Not applicable.

PART II

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

Market Information

Our common stock is traded on the NYSE MKT LLC under the symbol "GST." The following table sets forth the high and low sales prices of our common stock during the periods presented as reported by the NYSE MKT LLC.

	NYSE MKT LLC	
	High	Low
2015:		
Fourth quarter	$1.93	$1.00
Third quarter	$3.13	$1.00
Second quarter	$3.79	$2.58
First quarter	$3.27	$1.89
2014:		
Fourth quarter	$6.09	$2.11
Third quarter	$8.75	$5.85
Second quarter	$9.10	$5.72
First quarter	$7.13	$5.05

The last reported sale price of our common stock on the NYSE MKT LLC on March 7, 2016 was $1.06.

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Stockholders

As of March 7, 2016, there were 257 stockholders of record who owned shares of our common stock.

Dividends

We have never declared or paid any cash dividends on our common stock. We anticipate that we will retain future earnings, if any, to satisfy our operational and other cash needs and do not anticipate paying any cash dividends on our common stock in the foreseeable future. In addition, the agreements governing our Notes and Revolving Credit Facility prohibits us from paying cash dividends on our common stock as long as any debt remains outstanding.

Effective March 9, 2016, our Revolving Credit Facility was amended to, among other things, prohibit the payment of cash dividends on our preferred stock commencing April 2016. Dividends on the Series A and Series B Preferred Stock will accumulate regardless of whether any such dividends are declared. The Series A Preferred Stock dividend is a fixed rate of 8.625% per annum of the $25.00 per share liquidation preference, or $2.15625 per share outstanding each year, and on the Series B Preferred Stock a fixed rate of 10.75% per annum of the $25.00 per share liquidation preference, or $2.6875 per share outstanding each year. If the Company fails to pay full cash dividends in four calendar quarters, whether consecutive or non-consecutive, then the fixed rate of Series A and Series B Preferred Stock each increases by 2.00% and the holders, voting as a single class, will have the right to elect up to two directors to the board of directors of the Company. For the year ended December 31, 2015, preferred dividends paid totaled $14.5 million.

Issuer Purchases of Equity Securities

The following table sets forth our share repurchase activity for each period presented.

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans	(d) Maximum Number of Shares that May Yet be Purchased Under the Plan
November 1, 2015 - November 30, 2015	27,928	$ 1.50	—	n/a

Shares purchased represent shares of our common stock transferred to us in order to satisfy tax withholding obligations incurred upon the vesting of restricted stock units held by our employees and Board of Directors.

Recent Sales of Unregistered Securities

We did not have any sales of unregistered securities during the year ended December 31, 2015.

Item 6. Selected Financial Data

The following table presents selected historical financial data as of and for the periods indicated. The selected consolidated financial data are derived from our audited consolidated financial statements. The following selected historical financial data should be read in connection with Item 7. “Management’s Discussion and Analysis of Financial Condition and Results of Operations” and the audited Consolidated Financial Statements and related notes included elsewhere in this Form 10-K.

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Financial information as of and for the year ended December 31, 2015 includes impairment of oil and natural gas properties of $426.9 million. Financial information as of and for the year ended December 31, 2014 includes a gain of $23.9 million for the change in mark to market of commodity derivatives contracts held at December 31, 2014 and an $8.6 million net arbitration settlement benefit. Financial information as of and for the year ended December 31, 2013 includes a gain on acquisition of assets at fair value of $27.7 million. Financial information as of and for the year ended December 31, 2012 includes impairment of oil and natural gas properties of $150.8 million. Financial information as of and for the years ended December 31, 2013 and 2012 includes litigation settlement expense of $1.0 million and $1.3 million, respectively.

	As of and for the Years Ended December 31,				
	2015	2014	2013	2012	2011
	(in thousands, except per share data)				
Consolidated Statements of Operations:					
Revenues	$107,294	$171,418	$87,755	$49,940	$40,235
Income (loss) from operations	$(428,834)	$78,512	$18,764	$(153,528)	$(631)
Net income (loss) attributable to Common Stockholders	$(473,980)	$36,529	$39,964	$(160,868)	$(1,764)
Net income (loss) attributable to Common Stockholders per share:					
Basic	$(6.11)	$0.58	$0.66	$(2.53)	$(0.03)
Diluted	$(6.11)	$0.55	$0.63	$(2.53)	$(0.03)
Weighted average shares of common stock outstanding					
Basic	77,512	63,271	60,220	63,538	63,004
Diluted	77,512	66,493	63,618	63,538	63,004
Consolidated Balance Sheets:					
Property, plant and equipment, net	$328,934	$692,300	$517,513	$256,251	$285,740
Total assets	$430,868	$775,794	$589,935	$290,068	$334,503
Long-term liabilities	$527,085	$370,480	$325,802	$106,020	$39,438
Total stockholders' (deficit) equity	$(120,185)	$350,286	$210,029	$126,536	$235,194

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

You should read the following discussion of our historical performance, financial condition and future prospects in conjunction with the audited financial statements of Gastar Exploration Inc. and its subsidiaries as of the years ended December 31, 2015 and for the three years in the period ended December 31, 2015 together with the notes thereto included elsewhere in this Form 10-K.

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, Gastar is developing the primarily oil-bearing reservoirs of the Hunton Limestone horizontal oil play and is testing other prospective formations on the same acreage, including the Meramec Shale and the Woodford Shale, which is commonly referred to as the STACK Play, and emerging prospective plays in the shallow Oswego formation and in the Osage formation, a deeper bench of the Mississippi Lime located below the Meramec. In West Virginia, we have developed liquids-rich natural gas in the Marcellus Shale and have drilled and completed two successful dry gas Utica Shale/Point Pleasant wells on our acreage. On February 19, 2016, we entered into an agreement to sell substantially all of our assets and proved reserves and a significant portion of our undeveloped acreage in the Appalachian Basin for $80.0 million, subject to certain adjustments and customary closing conditions, including obtaining certain required lessor consents to assign. The transaction is expected to close on or before March 31, 2016, with an effective date of January 1, 2016. We completed the sale of substantially all of our East Texas assets in 2013.

On November 14, 2013, Parent 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 USA as part of a reorganization to eliminate the holding company corporate structure of Parent. Pursuant to the merger agreement, shares of Parent’s common stock were converted into an equal number of shares of common stock of Gastar USA and Gastar USA changed its name to “Gastar Exploration Inc.” Gastar Exploration Inc., together with its subsidiary, owns and continues to conduct Gastar’s business in substantially the same manner as was being conducted by Parent and its subsidiaries prior to the merger.

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All of our current operational activities are conducted in the U.S. As of December 31, 2015, our major assets consist of approximately 56,300 gross (36,900 net) acres in the Appalachian Basin in West Virginia and southwestern Pennsylvania and approximately 184,900 gross (110,700 net) acres in the Mid-Continent area of the U.S. in the state of Oklahoma. During the past three years, we spent approximately $777.2 million in property acquisitions, acreage, seismic, capitalized interest, drilling advances, reserve acquisition and exploratory and development drilling on this acreage. We attained positive net income during 2014 primarily due to the recognition of a gain of $23.9 million for the change in mark to market of commodity derivatives contracts held at December 31, 2014 and an $8.6 million net arbitration settlement benefit, and during 2013 primarily due to the recognition of a gain on acquisition of assets at fair value, net of taxes, of $27.7 million and the related income tax benefit for acquisition of $16.0 million, but there can be no assurance that operating income and net earnings will be achieved in future periods. As we continue the exploitation and development drilling in the Mid-Continent, we expect to show improvement in our operating results.

Our financial results depend upon many factors which significantly affect our results of operations including the following:

- The level and success of exploration and development activity;
- The sales prices of oil, condensate, natural gas and NGLs;
- The level of total sales volumes of oil, condensate, natural gas and NGLs; and
- The availability of and our ability to raise the capital necessary to meet our cash flow and liquidity needs.

We plan our activities and capital budget based on then current future period sales price assumptions, given the inherent volatility of oil, condensate, natural gas and NGLs prices that are influenced by many factors beyond our control. We focus our efforts on increasing oil, condensate, natural gas and NGLs reserves and production and strive to control costs at an appropriate level. Our future earnings and cash flows are dependent on our ability to manage our overall cost structure to a level that allows for profitable production. Our future earnings will also be impacted by the changes in the fair market value of hedges that we execute to mitigate the volatility in oil, condensate, natural gas and NGLs prices in future periods.

Like other oil and natural gas exploration and production companies, we face natural production declines. As initial reservoir pressures are depleted, oil, condensate, natural gas and NGLs production from a given well will decrease. Thus, an oil and natural gas exploration and production company depletes part of its asset base with each unit of oil, condensate, natural gas and NGLs that it produces. We attempt to overcome this natural decline by adding reserves in excess of what we produce through successful drilling or acquisition. Our future growth will depend on our ability to continue to add reserves in excess of our production. We will maintain our focus on adding reserves through drilling, while placing a clear priority on lowering our cost of replacing reserves. Consistent with our stated strategies, we will emphasize maintaining a high-quality inventory of drilling locations, while also focusing on improving our capital and cost efficiency.

2015 Highlights

Mid-Continent Horizontal Oil Play. At December 31, 2015, we held leases covering approximately 184,900 gross (110,700 net) acres in the Mid-Continent horizontal oil play and completed 14 gross (13.8 net) operated wells and 10 gross (6.6 net) non-operated wells, which we subsequently assumed operatorship of upon closing of the Husky Acquisition. On December 16, 2015, we completed the Husky Acquisition of additional interests in the AMI from our AMI co-participant including working and net revenue interests in 103 gross (10.2 net) producing wells and approximately 15,700 net developed and undeveloped acres in Kingfisher and Garfield Counties, Oklahoma and assumed operatorship of the acquired wells. At December 31, 2015, our proved reserves attributable to our Mid-Continent acreage were approximately 41.1 MMBoe. Mid-Continent proved reserves represented approximately

73% of our total proved reserves and approximately 94% of our pre-tax PV-10 value at December 31, 2015. Oil, condensate and NGLs reserves comprised approximately 78% of the total Mid-Continent proved reserves at year end 2015.

Utica Shale/Point Pleasant Drilling Program. At December 31, 2015, we held leases covering approximately 25,600 gross (10,300 net) acres in the Marcellus Shale that have Utica Shale/Point Pleasant potential. During 2015, we completed our second Utica Shale well, the Blake U-7H, which was drilled to a total vertical depth of 11,100 feet with an approximate 6,600 foot lateral. Our working interest in the Blake U-7H is 50% (net revenue interest 41.1%). Due to the continued low price environment in the Appalachian Basin, we suspended our drilling operations during 2015 and engaged a third-party to market certain Marcellus Shale and Utica Shale/Point Pleasant acreage, primarily located in Marshall and Wetzel Counties, West Virginia, including producing wells. At December 31, 2015, our proved reserves attributable to the Utica Shale acreage were approximately 7.1 Bcf of natural gas. Utica Shale proved reserves represented approximately 2% of our total proved reserves at December 31, 2015. On February 19, 2016, we entered into an agreement to sell substantially all of our assets and proved reserves and a significant portion of our undeveloped acreage in the Appalachian Basin for $80.0 million, subject to certain adjustments and customary closing conditions, including obtaining certain

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required lessor consents to assign. The transaction is expected to close on or before March 1, 2016 with an effective date of January 1, 2016.

Marcellus Shale Drilling Program. During the year ended December 31, 2015, we completed seven gross (3.5 net) operated wells in Marshall County, West Virginia, under the Atinum Participation Agreement. At December 31, 2015, we had 74 gross (37.0 net) operated wells on production in Marshall County, West Virginia. Due to the continued low price environment in the Appalachian Basin, we suspended our drilling operations during 2015 and engaged a third-party to market certain Marcellus Shale and Utica Shale/Point Pleasant acreage, primarily located in Marshall and Wetzel Counties, West Virginia, including producing wells. At December 31, 2015, our proved reserves attributable to our Marcellus Shale acreage were approximately 13.6 MMBoe. Marcellus Shale proved reserves represented approximately 24% of our total proved reserves and approximately 6% of our pre-tax PV-10 value at December 31, 2015. Oil, condensate and NGLs reserves comprised approximately 43% of the total Marcellus Shale proved reserves at year end 2015. On February 19, 2016, we entered into an agreement to sell substantially all of our assets and proved reserves and a significant portion of our undeveloped acreage in the Appalachian Basin for $80.0 million, subject to certain adjustments and customary closing conditions, including obtaining certain required lessor consents to assign. The transaction is expected to close on or before March 1, 2016 with an effective date of January 1, 2016.

Financial Highlights

Our consolidated financial statements reflect total revenue of $107.3 million on total volumes of 4.9 MMBoe for the year ended December 31, 2015. Our operating loss for the year ended December 31, 2015 was $428.8 million and included impairment of oil and natural gas properties of $426.9 million and depreciation, depletion and amortization expense of $62.9 million.

Results of Operations

The following is a comparative discussion of the results of operations for the periods indicated. It should be read in conjunction with the consolidated financial statements and the related notes to the consolidated financial statements, which are included in Item 8. “Financial Statements and Supplementary Data” of this Form 10-K.

For additional information about production volumes, prices of oil and natural gas and selected operating expenses, see Item 2. “Properties – Production, Prices and Operating Expenses” of this Form 10-K.

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The following table provides a summary of our revenues, production and operating expenses for the periods indicated:

	Year Ended December 31,		
	2015	2014	2013
	(In thousands, except per unit amounts)		
Revenues:			
Oil and condensate	$58,668	$82,820	$36,480
Natural gas	16,901	47,647	40,416
NGLs	7,136	21,382	15,611
Gain (loss) on commodity derivatives contracts	24,589	19,569	(4,752)
Total revenues	$107,294	$171,418	$87,755
Production:			
Oil and condensate (MBbl)	1,425	975	515
Natural gas (MMcf)	13,759	11,598	13,366
NGLs (MBbl)	1,213	801	494
Total production (MBoe)	4,931	3,708	3,236
Oil and condensate (MBbl/d)	3.9	2.7	1.4
Natural gas (MMcf/d)	37.7	31.8	36.6
NGLs (MBbl/d)	3.3	2.2	1.4
Total daily production (MBoe/d)	13.5	10.2	8.9
Average sales price per unit(1):			
Oil and condensate per Bbl, excluding impact of hedging activities	$41.17	$84.98	$70.91
Oil and condensate per Bbl, including impact of hedging activities(2)	$46.86	$83.86	$71.04
Natural gas per Mcf, excluding impact of hedging activities	$1.23	$4.11	$3.02
Natural gas per Mcf, including impact of hedging activities(2)	$1.81	$3.84	$3.43
NGLs per Bbl, excluding impact of hedging activities	$5.89	$26.71	$31.59
NGLs per Bbl, including impact of hedging activities(2)	$14.42	$26.53	$31.13
Average sales price per Boe, excluding impact of hedging activities	$16.77	$40.95	$28.58
Average sales price per Boe, including impact of hedging activities(2)	$22.14	$39.78	$30.20
Selected operating expenses (in thousands):			
Production taxes(3)	$2,877	$6,733	$4,651
Lease operating expenses(3)	$23,728	$19,323	$9,456
Transportation, treating and gathering(3)	$2,187	$3,679	$4,006
Depreciation, depletion and amortization	$62,887	$46,180	$32,449
Impairment of natural gas and oil properties	$426,878	$—	$—
General and administrative expenses(4)	$17,069	$16,485	$16,961
Selected operating expenses per Boe:			
Production taxes(3)	$0.58	$1.82	$1.44

Lease operating expenses[3]	$4.81	$5.21	$2.92
Transportation, treating and gathering[3]	$0.44	$0.99	$1.24
Depreciation, depletion and amortization	$12.75	$12.45	$10.02
General and administrative expenses[4]	$3.46	$4.45	$5.24
Production costs[5]	$4.98	$6.00	$4.05

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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