UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549
FORM 10-K

x ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(D) OF THE SECURITIES EXCHANGE ACT OF 1934
For the Fiscal Year Ended December 31, 2012

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: 001-32714
Commission file number: 001-35211

GASTAR EXPLORATION LTD.
GASTAR EXPLORATION USA, INC.
(Exact name of registrant as specified in its charter)

Alberta, Canada	98-0570897
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:

Gastar Exploration Ltd. Common Stock, No Par Value	NYSE MKT LLC
Gastar Exploration USA, Inc. 8.625% Series A Cumulative Preferred Stock	NYSE MKT LLC
(Title of each class)	(Name of Exchange on which registered)

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.

Gastar Exploration Ltd.	Yes	¨	No	ý

Gastar Exploration USA, Inc.	Yes	¨	No	ý

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Gastar Exploration Ltd.	Yes	¨	No	ý
Gastar Exploration USA, Inc.	Yes	¨	No	ý

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Gastar Exploration Ltd.	Yes	ý	No	¨
Gastar Exploration USA, Inc.	Yes	ý	No	¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Gastar Exploration Ltd.	Yes	ý	No	¨
Gastar Exploration USA, Inc.	Yes	ý	No	¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter)
is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Gastar Exploration Ltd.	¨
Gastar Exploration USA, Inc.	ý

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

Gastar Exploration Ltd.	Large accelerated filer	¨	Accelerated filer	ý
	Non-accelerated filer	¨	Smaller reporting company	¨
Gastar Exploration USA, Inc.	Large accelerated filer	¨	Accelerated filer	¨
	Non-accelerated filer	ý	Smaller reporting company	¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Securities Exchange Act of 1934).

Gastar Exploration Ltd.	Yes	¨	No	ý
Gastar Exploration USA, Inc.	Yes	¨	No	ý

The aggregate market value of the voting and non-voting common equity of Gastar Exploration Ltd. held by non-affiliates of Gastar Exploration Ltd. as of June 29, 2012 (the last business day of Gastar Exploration Ltd.'s most recently completed second fiscal quarter) was approximately $110.0 million based on the closing price of $1.93 per share on the NYSE MKT LLC.

All common equity in Gastar Exploration USA, Inc. is held by Gastar Exploration Ltd., an affiliate of Gastar Exploration USA, Inc. Gastar Exploration USA, Inc. meets the conditions set forth in General Instruction (I)(1)(a) and (b) and is filing this Form with the reduced disclosure format.

The total number of outstanding common shares, no par value per share, as of March 7, 2013 was:

Gastar Exploration Ltd.	68,450,241	shares of common stock

Gastar Exploration USA, Inc.	750	shares of common stock

DOCUMENTS INCORPORATED BY REFERENCE:
The information required by Part III of Form 10-K (Items 10, 11, 12, 13 and 14) is incorporated by reference from portions of Gastar Exploration Ltd.'s definitive proxy statement relating to its 2013 annual meeting of shareholders to be filed with the U.S. Securities and Exchange Commission ("SEC") within 120 days of December 31, 2012.

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GASTAR EXPLORATION LTD. AND SUBSIDIARIES
ANNUAL REPORT ON FORM 10-K FOR THE YEAR ENDED DECEMBER 31, 2012
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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K (this "Form 10-K") includes forward-looking information that is intended to be covered by the "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, 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," "ant "believe," "estimate," "predict," "potential," "pursue," "target" or "continue," the negative of such terms or variations thereon, other comparable terminology.

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

- financial position;
- business strategy and budgets;
- anticipated capital expenditures;
- drilling of wells, including the anticipated scheduling and results of such operations;
- natural gas, oil and NGLs reserves;
- timing and amount of future production of natural gas, condensate, oil and NGLs;
- operating costs and other expenses;
- cash flow and anticipated liquidity;
- prospect development; and
- property acquisitions and sales.

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

Factors that could cause actual results to differ materially from those anticipated or implied in the forward-looking statements herein include, but are not limited to:

- the supply and demand for natural gas, condensate, oil and NGLs;
- low and/or declining prices for natural gas, condensate, oil and NGLs;
- natural gas, condensate, oil and NGLs price volatility;
- worldwide political and economic conditions and conditions in the energy market;
- our ability to raise capital to fund planned capital expenditures or repay or refinance debt upon maturity;
- the ability and willingness of our current or potential counterparties, third-party operators or vendors to enter into transactions with us and/or to fulfill their obligations to us;
- failure of our joint interest partners to fund any or all of their portion of any capital program;
- the ability to find, acquire, market, develop and produce new natural gas and oil properties;
- uncertainties about the estimated quantities of natural gas and oil 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;

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

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

Unless otherwise indicated or required by the context, (i) “Gastar,” the “Company,” “we,” “us,” “our” and similar terms refer collectively to Gastar Exploration Ltd. and its subsidiaries, including Gastar Exploration USA, Inc., and predecessors, (ii) “Gastar USA” refers to Gastar Exploration USA, Inc., our first-tier subsidiary and primary operating company, (iii) “Parent” refers solely to Gastar Exploration Ltd., (iv) all dollar amounts appearing in this Form 10-K are stated in United States dollars (“U.S. dollars”) unless otherwise noted and (v) all financial data included in this Form 10-K have been prepared in accordance with generally accepted accounting principles in the United States of America (“U.S. GAAP”).

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Glossary of Terms

AMI	Area of Mutual Interest, an agreed designated geographic area where joint venturers or other industry partners have a right of participation in acquisitions and operations
Bbl	Barrel of oil, condensate or NGLs
Bbl/d	Barrels of oil, condensate or NGLs per day
Bcf	One billion cubic feet of natural gas
Bcfe	One billion cubic feet of natural gas equivalent, determined using the ratio of six cubic feet of natural gas to one barrel of oil, condensate or NGLs
Btu	British thermal unit, typically used in measuring natural gas energy content
CBM	Coal bed methane
CRP	Central receipt point
FASB	Financial Accounting Standards Board
GAAP	Accounting principles generally accepted in the United States of America
MBbl	One thousand barrels of oil, condensate or NGLs
MBbl/d	One thousand barrels of oil, condensate or NGLs 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, determined using the ratio of six cubic feet of natural gas to one barrel of oil, condensate or NGLs
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, determined using the ratio of six cubic feet of natural gas to one barrel of oil, condensate or NGLs
MMcfe/d	One million cubic feet of natural gas equivalent per day, determined using the ratio of six cubic feet of natural gas to one barrel of oil, condensate or NGLs
NGLs	Natural gas liquids
NYMEX	New York Mercantile Exchange

psi	Pounds per square inch
U.S.	United States

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PART I

Item 1. Business
Overview
We are an independent energy company engaged in the exploration, development and production of natural gas, condensate, oil and NGLs in the U.S. Our principal business activities include the identification, acquisition, and subsequent exploration and development of natural gas and oil properties with an emphasis on unconventional reserves, such as shale resource plays. We are currently pursuing the development of liquids-rich natural gas in the Marcellus Shale play in West Virginia and, to a lesser extent, central and southwestern Pennsylvania and oil in the Mid-Continent area of the U.S. We also hold prospective acreage in the deep Bossier play in the Hilltop area of East Texas.
Gastar Exploration Ltd. is a Canadian corporation, incorporated in Alberta in 1987 and subsisting under the Business Corporations Act (Alberta), with its common shares listed on the NYSE MKT LLC under the symbol “GST.” Gastar Exploration Ltd. is a holding company and substantially all of its operations are conducted through, and substantially all of its assets are held by, its primary operating subsidiary, Gastar USA and its wholly-owned subsidiaries. Gastar USA is a Delaware corporation with its 8.625% Series A Cumulative Preferred Stock listed on the NYSE MKT LLC under the symbol “GST.PRA.” Our principal office is located at 1331 Lamar Street, Suite 650, Houston, Texas 77010, and our telephone number is (713) 739-1800. Our website address is http://www.gastar.com. Information on our website or about us on any other website is not incorporated by reference into and does not constitute part of this Form 10-K.
Our Strategy
Our strategy is to increase stockholder value by delivering sustainable reserves growth and improved operating results from our existing assets. We recognize that there may be periods, such as the recent declines in natural gas prices, which make it difficult to fully execute this strategy on a short-term basis. We intend to implement our strategy by focusing on:

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

Continue Exploitation of Existing Marcellus Shale Assets and Focus on Areas with Relatively High NGLs and Condensate Content
We are continuing to focus the majority of our drilling activity in the liquids-rich area of the Marcellus Shale, with approximately 64% of our 2013 capital budget allocated to the Marcellus Shale. Our 2013 capital budget includes plans to place on production an additional 19 gross (9.5 net) operated Marcellus horizontal wells in Marshall County, West Virginia, if we successfully implement our planned drilling program. We believe that the expansion of our acreage position and our drilling activity in the Marcellus Shale during 2012 has provided us with a multi-year inventory of drilling opportunities. Our focus continues to be in a prospectively liquids-rich area with subsequent focus on drilling acreage in order to hold the acreage "by production" prior to lease term expirations.
Exploitation and Development within a Mid-Continent Horizontal Oil Play
During 2012, we acquired approximately 41,900 gross (17,300 net) acres of leasehold in an emerging oil play located in the Mid-Continent region of the U.S. We expect to continue to build our acreage position in this region in partnership with our operating partner during 2013. This program is focused on using modern horizontal drilling and multi-stage fracture stimulation technologies to exploit a predominantly crude oil-bearing reservoir, which has been produced historically using vertical wells conventional with completion techniques. During 2012, we, along with our operating partner, drilled and completed one horizontal well and spud two additional horizontal wells. Based on the 30 days ended February 20, 2013, the initial well produced at an after-processing average gross rate of 105 barrels of oil equivalent per day, comprised of 69 barrels of oil per day, 20 barrels of NGLs per day, 94 Mcf of natural gas per day and 247 barrels of completion fluids per day. Flow back operations on the second well commenced on February 15,

2013, with encouraging preliminary results. Drilling operations on the third well were completed during February 2013 and completion operations are scheduled to commence in mid-March 2013. A fourth horizontal well was spud on February 16, 2013. For the first 12,500 gross acres acquired in the initial AMI prospect, we paid 62.5% of lease acquisition costs for a 50% leasehold interest and 50% of lease acquisition costs on additional acres in excess of 12,500 gross acres acquired for a 50% working interest. We will pay 54.25% of the lease acquisition costs in the two new prospect areas for a 50% working interest. In each prospect area, we pay 62.5% of the gross drilling and completion costs of the first four wells and 56.25 % of the gross drilling and completion costs of the next four

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wells, in each case to earn a 50% working interest. For all additional wells beyond the first eight in a prospect area, we are responsible for paying only the drilling and completion costs associated with our 50% working interest (our approximate net revenue interest is 39.0%). A third-party operator handles all drilling, completion and production activities, and we handle all leasing and permitting activities in this oil play.

Actively Manage Our Domestic Drilling Program

We believe that operating approximately 70% of our drilling projects for 2013 enables us to control the timing and cost of our drilling budget as well as control operating costs and the marketing of our production. 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 Marcellus Shale wells.

Manage and Utilize Technological Expertise

We believe that 3-D seismic analysis, 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.

Natural Gas and Oil Activities

The following provides an overview of our major natural gas and oil projects during 2012. While actively pursuing specific exploration and development activities in each of the following areas, we continue to review other opportunities. There is no assurance that new drilling opportunities will be identified or that any new drilling opportunities will be successful if drilled.

Marcellus Shale and Other Appalachia

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 stimulation have produced excellent results in the Marcellus Shale. These developments have resulted in increased leasing and drilling activity in the area. As of December 31, 2012, our acreage position in the play was approximately 107,600 gross (75,200 net) acres. We refer to the approximately 46,900 gross (20,900 net) acres reflecting our interest in our Marcellus Shale assets in West Virginia and Pennsylvania subject to the Atinum Joint Venture described below as our “Marcellus West acreage.” We refer to the approximately 60,700 gross (54,200 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 Joint Venture” pursuant to a purchase and sale agreement with an affiliate of Atinum Partners Co. Ltd. (“Atinum”). Pursuant to the agreement, at the closing of the transaction on November 1, 2010, we assigned to Atinum, for $70.0 million in total consideration, an initial 21.43% interest in all of our existing Marcellus Shale assets in West Virginia and Pennsylvania, consisting of certain undeveloped acreage and a 50% working interest in 16 producing shallow conventional wells and one non-producing vertical Marcellus Shale well (the “Atinum Joint Venture Assets”). Atinum paid us approximately $30.0 million in cash upon closing. Additionally, Atinum was obligated to fund its 50% share of drilling, completion and infrastructure costs, and paid an additional $40.0 million of drilling costs in the form of a drilling carry obligation by funding 75% of our 50% share of those same costs. Upon completion of the funding of the drilling carry at December 31, 2011, we made additional assignments in early 2012, as necessary, to Atinum as a result of which Atinum now owns a 50% interest in the Atinum Joint Venture Assets.

The Atinum Joint Venture's initial three-year development program called for the partners to drill a minimum of 12 horizontal wells in 2011 and 24 horizontal wells in each of 2012 and 2013 for a total of 60 wells to be drilled. Due to natural gas price declines, Atinum and Gastar USA agreed during the first quarter 2012 to reduce the 2012 minimum wells to be drilled requirement from 24 wells to 20 wells. Atinum and Gastar USA subsequently agreed to extend the rig contract in the Marcellus Shale to May 2013, resulting in 29 gross operated wells drilled and completed during 2012 and 38 gross wells on production at December 31, 2012. All of our 2012 Marcellus Shale well operations were under the Atinum Joint Venture. Additionally, Atinum and Gastar USA agreed to reduce the 2013 minimum wells to 19 gross wells which will result in 57 gross wells on production at December 31, 2013, compared to the 60 gross wells originally agreed upon. Effective June 30, 2011, Atinum has the right to participate in any future leasehold acquisitions made by us within Ohio, New York, Pennsylvania and West Virginia, excluding the counties of Pendleton, Pocahontas, Preston, Randolph and Tucker, West Virginia, on terms identical to those governing the existing Atinum Joint Venture. We will act as operator and are obligated to offer any future lease acquisitions to

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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.
As of December 31, 2012, our operated wells capable of production in Marshall County, West Virginia were comprised of the following:

Pad	Gross Well Count	Net Well Count	Working Interest	Net Revenue Interest	Average Lateral Length (in feet) (1)	Date on Production
Corley	4.0	1.6	40.8%	35.4%	4,900	December 2011
Simms	3.0	1.5	50.0%	43.2%	5,000	December 2011
Hall	3.0	1.2	40.0%	34.7%	4,400	January 2012
Hendrickson	5.0	2.0	40.0%	34.7%	4,700	April 2012
Accettolo	3.0	1.5	50.0%	40.2%	4,600	June 2012
Burch Ridge	5.0	2.5	50.0%	41.5%	5,800	August 2012
Wayne	4.0	2.0	50.0%	40.6%	5,700	September 2012
Wengerd	7.0	3.1	44.5%	37.7%	5,000	November 2012
Lily	4.0	2.0	50.0%	40.6%	5,200	December 2012
	38.0	17.4				

(1) Average well lateral length approximates the actual average well lateral length for the pad wells.

As of December 31, 2012, we had drilling operations at various stages on the following wells in Marshall County, West Virginia:

Pad	Gross Well Count	Net Well Count	Working Interest	Estimated Net Revenue Interest	Average Lateral Length (in feet) (1)	Status	Estimated Production Date
Addison	5.0	2.5	50.0%	41.7%	4,900	Drilling operations in progress	Late First Quarter 2013
Shields	10.0	5.0	50.0%	42.0%	3,400	Drilling and fracture stimulation operations in progress	Mid-First and Third Quarters 2013
	15.0	7.5					

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

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As of March 8, 2013, we have the following drilling operations in Marshall County, West Virginia:

Pad	Gross Well Count	Net Well Count	Working Interest	Estimated Net Revenue Interest	Average Lateral Length (in feet) (1)	Status	Estimated Production Date
Addison	5.0	2.5	50.0%	41.7%	4,900	Fracture stimulation in progress	Late First Quarter 2013
Shields	10.0	5.0	50.0%	42.0%	3,400	5 wells producing and 5 awaiting fracture stimulation	Late First and Third Quarters 2013
Goudy (2)	4.0	2.0	50.0%	40.5%	5,600	Drilling operations in progress	Third Quarter 2013
	19.0	9.5					

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

(2) Goudy pad to ultimately have nine wells.

In December 2010, we completed a Marcellus Shale leasehold acquisition for our Marcellus East acreage for an aggregate purchase price of $28.9 million. The acquisition consisted of undeveloped leasehold in the Marcellus Shale concentrated in Preston, Tucker, Pocahontas, Randolph and Pendleton Counties, West Virginia, including a gathering system comprised of 41 miles of four and six inch steel pipeline, a salt water disposal well, and five conventional producing wells. The Marcellus East acreage was outside the initial AMI with Atinum. Atinum elected not to acquire a 50% interest as provided under the terms of the Atinum Joint Venture. We believe their decision was due to the timing of the transaction and limited prior operational results within the initial Atinum Joint Venture AMI. We have completed the drilling of the Hickory Ridge 2H horizontal Marcellus well in Marcellus East in Preston County, West Virginia, in August 2011. The well was drilled with a 2,500 foot lateral and completed with a ten-stage fracture stimulation. Due to low natural gas prices, and in an effort to reduce operating costs, during the fourth quarter of 2012, we installed a pump jack to assist with accelerating the recovery of the completion fluids from the well. As of March 8, 2013, the well has recovered approximately 61% of the fluids used in its completion. Nearby vertical wells experienced low gas rates prior to recovering at least 75% of completion fluids. Due to the current natural gas price environment, we are not currently planning to drill any additional wells on the Marcellus East acreage during 2013 but will continue to monitor our Marcellus producing wells and activity and the activity of our offset operators.

As of December 31, 2012, we had participated on a non-operated basis in the drilling of seven horizontal Marcellus Shale wells in Butler County, Pennsylvania and an additional four non-operated horizontal Marcellus Shale wells in Marshall County, West Virginia. Three of the seven Butler County wells were turned to production on December 1, 2011 with the remaining four wells completed and turned to sales in March 2012. Our average working interest in the Butler County non-operated wells is 19.2% (our average net revenue interest is 15.9%) and the average lateral length of the wells is 3,900 feet. Of the four Marshall County non-operated wells, two of the wells were on production prior to December 31, 2011 and the remaining wells were placed on production by mid-April 2012. Our current average working interest in the Marshall County non-operated wells is 22.2% (our average net revenue interest is 17.8%) and the average well lateral length is approximately 4,200 feet. Currently, we do not plan to participate in any additional Marcellus Shale non-operated wells for 2013.

For the year ended December 31, 2012, net production from the Marcellus Shale averaged 22.0 MMcfe/d compared to 2.4 MMcfe/d in 2011. For the three months ended December 31, 2012, net production from the Marcellus Shale averaged 29.9 MMcfe/d compared to 23.3 MMcfe/d for the three months ended September 30, 2012 and 5.2 MMcfe/d for the three months ended December 31, 2011. During the last several quarters, our operated production and sales in West Virginia have been 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 has been gradually resolving these issues and certain issues were resolved in May 2012 by increasing dehydration capacity to 70 MMcf/d from 40 MMcf/d and adding compression to reduce line pressure to approximately 550 psi at the Corley CRP. An additional CRP is to be constructed at the Burch Ridge pad and will have 75 MMcf/d dehydration capacity and compression to ensure line pressures are maintained at approximately 550 psi. The third-party gathering system downtime during 2012 resulted in reduced production of approximately 5.0 MMcfe/d, or 14% of total production for the year. The Burch Ridge CRP, originally scheduled to become operational during December 2012, is currently expected to become operational in mid-March 2013 reducing line pressure and limitations to dehydration capacity.

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At December 31, 2012, proved reserves attributable to the Marcellus Shale were approximately 153.2 Bcfe, an 82% increase from year-end 2011 reserves of 84.0 Bcfe. As of December 31, 2012, Marcellus Shale proved reserves represented approximately 85% of our total proved reserves compared to 70% of total proved reserves at December 31, 2011. Total Marcellus Shale proved reserves at year-end 2012 were comprised of approximately 32% of condensate and oil and NGLs reserves compared to 33% at year-end 2011. Approximately 65% of the Marcellus Shale year-end 2012 reserves are proved developed compared to 51% at December 31, 2011.

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

	For the Years Ended December 31,		
Marcellus Shale and Other Appalachia	2012	2011	2010
Production:			
Natural gas (MMcf)	5,477	672	118
Condensate and oil (MBbl)	160	11	2
NGLs (MBbl)	270	21	—
Total production (MMcfe)	8,058	860	133
Natural gas (MMcf/d)	15.0	1.8	0.3
Condensate and oil (MBbl/d)	0.4	—	—
NGLs (MBbl/d)	0.7	0.1	—
Total daily production (MMcfe/d)	22.0	2.4	0.4
Average sales price per unit (1):			
Natural gas (per Mcf)	$2.33	$3.43	$4.02
Condensate and oil (per Bbl)	$62.40	$71.37	$71.14
NGLs (per Bbl)	$28.22	$52.47	$—
Average sales price per Mcfe (1)	$3.77	$4.82	$4.88
Selected operating expenses (in thousands):			
Production taxes	$2,138	$272	$30
Lease operating expenses	$2,070	$832	$393
Transportation, treating and gathering	$1,090	$85	$1
Selected operating expenses per Mcfe:			
Production taxes	$0.27	$0.32	$0.23
Lease operating expenses	$0.26	$0.97	$2.96
Transportation, treating and gathering	$0.14	$0.10	$0.01
Production costs (2)	$0.38	$1.03	$2.88

(1) Excludes the impact of realized hedging activities.

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

For the fiscal year 2013, in Marshall County, West Virginia, we currently anticipate that we will place on production an additional 19 gross (9.5 net) operated horizontal Marcellus Shale wells. Based on this projected activity, and assuming successful completion of wells budgeted for completion in 2013, we anticipate having 57 gross (26.9 net) operated wells on production by year-end 2013.

Hilltop Area, East Texas

At December 31, 2012, we held leases covering approximately 33,000 gross (17,000 net) acres in the Bossier play in the Hilltop area of East Texas in Leon and Robertson Counties. The Bossier play is an unconventional play characterized by Jurassic-age series of sands deposited in an ancient deepwater environment in mini-basins or depositional lows and on the flanks of structures that existed at the time of deposition. Wells in this area target multiple potentially productive natural gas formations and are typically characterized by high initial production and attractive long-lived reserves per well. Due to low natural gas prices, we suspended all Bossier drilling activities in the Hilltop area for 2012. We do not currently have any plans in our 2013 capital budget to drill any additional wells in the Bossier play and are also considering a possible divestiture of our East Texas assets to fund a portion of our 2013 capital plan. However, we continue to monitor offset horizontal drilling activity in the Eagle Ford and Woodbine formations by Encana Corporation, EOG Resources, Inc. and other companies and may revise

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our capital plan to include an Eagle Ford or Woodbine test well in 2013 should the drilling results of the offset operators indicate that the economics would be attractive.

For the year ended December 31, 2012, net production from the Hilltop area averaged 13.7 MMcfe/d compared to 17.3 MMcfe/d for the year ended December 31, 2011. For the three months ended December 31, 2012, net production from the Hilltop area averaged approximately 12.4 MMcfe/d compared to 15.5 MMcfe/d for the three months ended December 31, 2011.

At December 31, 2012, proved reserves attributable to the Hilltop area were approximately 27.4 Bcfe, representing approximately 15% of our total proved reserves and of which 100% is proved developed. This compares to proved reserves of 34.3 Bcfe, or approximately 29% of our total proved reserves, at December 31, 2011.

The following table provides production and operational information about the Hilltop area for the periods indicated:

	For the Years Ended December 31,		
Hilltop Area, East Texas	2012	2011	2010
Production:			
Natural gas (MMcf)	4,914	6,127	6,756
Condendsate and oil (MBbl)	15	30	8
Total production (MMcfe)	5,005	6,304	6,803
Natural gas (MMcf/d)	13.4	16.8	18.5
Condensate and oil (MBbl/d)	—	0.1	—
Total daily production (MMcfe/d)	13.7	17.3	18.6
Average sales price per unit (1):			
Natural gas (per Mcf)	$2.06	$3.17	$3.49
Condensate and oil (per Bbl)	$95.71	$90.12	$73.10
Average sales price per Mcfe (1)	$2.31	$3.51	$3.55
Selected operating expenses (in thousands):			
Production taxes	$84	$153	$40
Lease operating expenses	$3,624	$5,863	$4,399
Transportation, treating and gathering	$3,746	$3,962	$4,038
Selected operating expenses per Mcfe:			
Production taxes	$0.02	$0.02	$0.01
Lease operating expenses	$0.72	$0.93	$0.65
Transportation, treating and gathering	$0.75	$0.63	$0.59
Production costs (2)	$1.39	$1.45	$1.14

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(1) Excludes the impact of realized hedging activities.

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

Mid-Continent Horizontal Oil Play

At December 31, 2012, we held leases covering approximately 41,900 gross (17,300 net) acres in the non-operated Mid-Continent horizontal oil play. Our leasing activities in the initial AMI prospect area have been expanded to include two additional adjacent prospect areas. We expect to continue to build our acreage position in this region with our operating partner during 2013. For the first 12,500 gross acres acquired in the initial AMI prospect, we paid 62.5% of lease acquisition costs for a 50% leasehold interest and 50% of lease acquisition costs on additional acres in excess of 12,500 gross acres acquired for a 50% working interest. We will pay 54.25% of the lease acquisition costs in the two new prospect areas for a 50% working interest. In each prospect area, we pay 62.5% of the first four wells' gross drilling and completion costs and 56.25 % of the next four wells' gross drilling and completion costs to earn a 50% working interest. For all additional wells beyond the first eight in a prospect area, we are responsible for paying only the drilling and completion costs associated with our 50% working interest (our approximate net revenue interest is 39.0%). A third-party operator handles all drilling, completion and production activities, and we handle all leasing and permitting activities in this oil play.

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In late July 2012, drilling operations commenced on the first of three wells to be drilled during 2012 on the initial prospect area. The first well has a horizontal lateral of approximately 4,200 feet and fracture stimulation operations were completed in late September 2012. Costs to drill and complete the first well were $4.8 million gross ($3.0 million net). Well flow back operations commenced on October 5, 2012. This well was completed at an initial 30-day after-processing average gross rate of 105 barrels of oil equivalent per day, comprised of 84 barrels of oil per day, 12 barrels of NGLs per day, 57 Mcf of natural gas per day and 428 barrels of completion fluids per day. The well continues to unload completion fluids with approximately 31% of frac fluid flowed back as of March 7, 2013. Based on the 30 days ended February 20, 2013, the well is currently producing at an after-processing average gross rate of 105 barrels of oil equivalent per day, comprised of 69 barrels of oil per day, 20 barrels of NGLs per day, 94 Mcf of natural gas per day and 247 barrels of completion fluids per day. Drilling operations on the second well commenced in November 2012. The second well has a horizontal lateral of approximately 4,100 feet and fracture stimulation and plug drill out operations were completed on January 23, 2013. Costs to drill and complete the second well were approximately $5.1 million gross ($3.2 million net). Well flow back operations commenced in early February 2013. Production results for the second well are encouraging but have not been disclosed for competitive reasons. Drilling operations on the third well with a horizontal lateral of 4,300 feet commenced on December 31, 2012 on the initial prospect area and were completed during February 2013. Completion operations on the third well are scheduled to commence in mid-March 2013. A fourth well was spud on February 16, 2013.

For the fiscal year 2013, in the Mid-Continent, we currently anticipate that we will drill an additional eight gross (4.0 net) wells and place on production nine gross (4.5 net) non-operated horizontal Mid-Continent wells. Based on this projected activity, and assuming successful completion of wells budgeted for completion in 2013, we anticipate having 10 gross (5.0 net) non-operated Mid-Continent wells on production by year-end 2013.

Powder River Basin, Wyoming and Montana

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

Markets and Customers

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

We contract to sell natural gas from our properties with spot market contracts that vary with market forces on a daily basis. While overall natural gas prices at major markets, such as Henry Hub in Erath, Louisiana, may have some impact on regional prices, the regional natural gas price at our production facilities may move somewhat independently of broad industry price trends. Because some of our operations are located in specific regions, we are directly impacted by regional natural gas prices in those regions 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 in our Hilltop area of East Texas and in the Appalachian Basin. In East Texas, ETC Texas Pipeline, Ltd. (“ETC”) provides for the treating, purchase and transportation of substantially all of our natural gas production from this area. Our deep Bossier production is transported to the Katy Hub in Katy, Texas, where numerous parties are available to purchase our natural gas production. Our Appalachian Basin production is sold on the spot market to regional pipeline companies. There are numerous natural gas purchasers and transport and processing options in the area of our Mid-Continent horizontal oil play, and all natural gas production from this region is sold on the spot market to regional pipeline companies. Prior to the assignment of our interest in the Powder River Basin to the operator, our Powder River Basin natural gas was sold under spot market contracts to major pipeline and natural gas marketing companies.

Our oil, NGLs and condensate production in East Texas, 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.

During December 2010, we, along with Atinum, entered into a gas purchase agreement with SEI Energy, LLC (“SEI”) with respect to our 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. SEI will purchase all hydrocarbon production, including all natural gas, condensate and natural gas liquids. SEI has an agreement to utilize the Williams Ohio

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Valley Midstream LLC (“Williams”) midstream facilities (formerly owned by Caiman Energy Midstream, LLC), including its 120.0 MMcf per day 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. During 2012, our operated production and sales in West Virginia were impacted by issues with high line pressures on the Williams gathering system. Williams anticipates completing the Burch Ridge CRP by mid-March 2013, which should help alleviate the high line pressure issues on the gathering system and the impact of such on our production and sales in West Virginia.

On November 16, 2009, concurrent with the sale of our Hilltop gathering system in East Texas, our wholly-owned subsidiary entered into a gas gathering agreement effective November 1, 2009 with Hilltop Resort GS, LLC (the “Hilltop Gathering Agreement”) for a term of 15 years. The Hilltop Gathering Agreement covers delivery of our gross production of natural gas in the Hilltop area of East Texas to certain delivery points provided under the ETC Contract as well as additional delivery points that, from time to time, may be added. We also are obligated to connect new wells that we drill within the area covered by the agreement to the gathering system. The Hilltop Gathering Agreement provides for a minimum quarterly gathering gross production volume of 50.0 MMcf per day (35.0 MMcf per day net to us) times the number of days in the quarter for five years from the effective date of November 1, 2009. If quarterly production is less than the minimum quarterly requirement, the gathering fee is payable on such deficit. If excess quarterly production exists, such excess is carried forward to offset any future deficit quarters. The gathering fee on the initial gross 25 Bcf of production is $0.325 per Mcf, reducing in steps to $0.225 per Mcf when cumulative gross production reaches 300 Bcf.

In March 2008, we entered into formal agreements with ETC for the treating, purchase and transportation of substantially all of our natural gas production from the Hilltop area of East Texas (the “ETC Contract”). The ETC Contract was effective as of September 1, 2007 and has a term of 10 years. ETC currently provides us with 50.0 MMcf per day of treating capacity and 150.0 MMcf per day of transportation capacity of production from our wells located in Leon and Robertson Counties, Texas.

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

	For the Years Ended December 31,		
	2012	2011	2010
SEI	47 %	8 %	— %
ETC	24 %	69 %	86 %
Clearfield Appalachian	14 %	— %	— %
Plains Marketing LP	2 %	10 %	2 %

SEI and Clearfield Appalachian purchase the majority of the Company's Marcellus Shale production. ETC treats, transports and purchases substantially all of the Company’s East Texas natural gas production. Plains Marketing LP purchases substantially all of the Company's East Texas oil production. There are limited natural gas purchase and transportation alternatives currently available in the Hilltop area of East Texas and in Appalachia. If SEI, ETC, Clearfield Appalachian, or Plains were to cease purchasing and transporting the Company’s natural gas, condensate and oil and NGLs production and the Company was 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, the Company’s ability to conduct normal operations would be restricted. However, the Company believes that the loss of SEI, ETC, Clearfield Appalachian or Plains would not have a long-term material adverse impact on the Company’s financial position or results of operations, as there are other purchasers operating in the areas. See “Item 1A. Risk Factors - Our ability to market our natural gas, condensate, oil and NGLs may be impaired by capacity constraints and availability of the gathering systems and pipelines that transport our natural gas, condensate, oil and NGLs.”

Competition

The natural gas and oil industry is intensely competitive and speculative in all of its phases. We encounter competition from other natural gas and oil companies in all areas of our operations. In seeking suitable natural gas and oil properties for acquisition, we compete with other companies operating in our areas of interest, including large natural gas and oil 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 natural gas and oil but also market natural gas and oil and other products on a regional, national or worldwide basis. These competitors may be able to pay more for productive natural gas and oil properties and exploratory prospects and define, evaluate, bid for and purchase a greater

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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. See “Item 1A.-Risk Factors - Competition in the natural gas and oil 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 natural gas and oil production are controlled by market forces. Competition in the natural gas and oil 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 natural gas and oil drilling rigs and in providing the manpower to operate them and provide related services.

Seasonal Nature of Business

Generally, the demand for natural gas decreases during the summer months and increases during the winter months. Seasonal anomalies such as mild winters or abnormally hot summers sometimes lessen this fluctuation. In addition, certain natural gas users utilize natural gas storage facilities and purchase some of their anticipated winter requirements during the summer. This can also lessen seasonal demand fluctuations. Seasonal weather conditions and lease stipulations can limit our drilling and producing activities and other natural gas and oil 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 natural gas and oil exploration, production and related operations are subject to extensive rules and regulations promulgated in the United States. These laws and regulations, all of which are subject to change from time to time, include matters relating to land tenure; drilling and production practices, such as discharge permits and the spacing of wells; the disposal of water resulting from operations and the processing, handling and disposal of hazardous materials, such as hydrocarbons and naturally occurring radioactive materials; bonding requirements; ongoing obligations for licensing; reporting requirements; marketing and pricing policies; royalties; taxation; and foreign trade and investment.

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

The regulatory burden on the natural gas and oil industry increases our cost of doing business and affects our financial condition. Although we believe we are in substantial compliance with all applicable laws and regulations, we are unable to predict the future cost or impact of complying with such laws because those laws and regulations are frequently amended or reinterpreted. We are unable to predict what additional legislation or amendments may be proposed that will affect our operations or when any such proposals, if enacted, might become effective. We do not expect that any of these laws would affect us in a materially different manner than any other similarly sized natural gas and oil company operating in the United States.

Regulation of Exploration and Production

Regulation of Production

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

Regulation of Sales of Natural Gas

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

Regulation of Availability, Terms and Cost of Pipeline Transportation

The availability, terms and cost of transportation can significantly affect sales of natural gas. FERC regulates interstate natural gas pipeline transportation rates and service conditions, which affect the marketing of natural gas produced by us and the revenues received by us for sales of such natural gas. FERC requires interstate pipelines to offer available firm transportation capacity on an open access, non-discriminatory basis to all natural gas shippers. FERC frequently reviews and modifies its regulations regarding the transportation of natural gas with the stated goal of fostering competition within all phases of the natural gas industry. In addition, with respect to production onshore or in state waters, the intra-state transportation of natural gas would be subject to state regulatory jurisdiction as well.

The ability of our facilities to deliver natural gas into third party natural gas pipeline facilities is directly impacted by the gas quality specifications required by those pipelines. In 2006, FERC issued a policy statement on provisions governing gas quality and interchangeability in the tariffs of interstate gas pipeline companies and a separate order declining to set generic prescriptive national standards. FERC strongly encouraged all natural gas pipelines subject to its jurisdiction to adopt, as needed, gas quality and interchangeability standards in their FERC gas tariffs modeled on the interim guidelines issued by a group of industry representatives headed by the Natural Gas Council (the "NGC+ Work Group"), or to explain how and why their tariff provisions differ. We have no way to predict, however, whether FERC will approve of gas quality specifications that materially differ from the NGC+ Work Group's interim guidelines for such an interconnecting pipeline.

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

Other Federal Laws and Regulations Affecting Our Industry

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

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

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

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

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

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

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

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

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

U.S. Environmental and Occupational Safety and Health Regulation

Our natural gas and oil exploration and production operations, and similar operations that we do not operate but in which we own a working interest, are subject to stringent federal, regional, state and local environmental laws and regulations governing water safety and health, environmental protection and the discharge of substances into the environment. These laws are implemented principally by the U.S. Environmental Protection Agency ("EPA"), the Department of Transportation, the Department of the Interior, the Occupational Safety and Health Administration and other comparable state agencies. These laws and regulations may require that permits, including drilling permits, be obtained before conducting regulated activities; restrict the types, quantities and concentrations of various substances that can be released into the environment as a result of natural gas and oil drilling, production and processing activities; suspend, limit or prohibit construction, drilling and other activities in certain lands lying within wilderness, wetlands and other protected areas; 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; impose liabilities for pollution resulting from our operations; and restrict injection of liquids into subsurface strata that may contaminate groundwater. Governmental authorities have the power to enforce compliance with their laws, regulations and permits, and violations may result in the issuance of injunctions limiting or prohibiting operations as well as administrative, civil and even criminal penalties. The effects of these laws and regulations, as well as the assessment of other laws or regulations that are adopted in the future, could have a material adverse impact on our operations and other operations in which we own an interest.

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

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

Hazardous Substances and Wastes

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

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

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

Water Discharges

Our operations and other operations in which we own a working interest are subject to the Federal Water Pollution Control Act, also known as the Clean Water Act, as amended (“CWA”), as well as the Oil Pollution Act, as amended (“OPA”), and analogous state laws. These laws and their implementing regulations impose detailed requirements and strict controls regarding the discharge of pollutants, including spills and leaks of oil and hazardous substances, into federal and state waters, including wetlands. In addition, depending on the location, discharges from or the withdrawal of water for use in our operations may be subject to regulation by regional or local regulatory authorities. Spill prevention, control and countermeasure, or

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. Under the CWA and the OPA, any unauthorized release of pollutants from operations could cause us to become subject to the costs of remediating a release, including administrative, civil or criminal fines or penalties in addition to OPA specified damages, such as damages for loss of use and natural resource damages. 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 U.S.

Our natural gas and oil exploration and production operations, and other operations in which we own an interest, generate produced water as a waste material, which is subject to regulation under the CWA, the Safe Drinking Water Act, as amended ("SDWA"), or an equivalent state regulatory program. Naturally occurring groundwater is also typically produced by operations in which we own an interest. This produced water is disposed of by injection into the subsurface through disposal wells permitted under the SDWA or an equivalent state regulatory program, discharge to surface water in compliance with permits issued by regulatory agencies pursuant to the CWA or an equivalent state program, or in evaporation ponds. While we believe that the produced water generated by our operations has been discharged or disposed of in substantial compliance with applicable environmental laws and regulations, any changes in the laws or regulations or the inability to obtain permits for new injection wells in the future may affect our ability to dispose of produced waters and ultimately increase the cost of our operations, which costs could be significant.

Hydraulic Fracturing

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil 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, but the EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and published draft permitting guidance in May 2012 addressing the performance of such activities using diesel fuels. In November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing and the agency currently plans to issue a Notice of Proposed Rulemaking that would seek public input on the design and scope of such disclosure regulations. In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, some states, including 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. 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 have been conducted or 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. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater, with a first progress report outlining work currently underway by the agency released on December 21, 2012 and a final report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review by 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards by 2014. Other governmental agencies, including the U.S. Department of Energy and the U.S. Department of the Interior, have evaluated or are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies, depending on their degree of pursuit and any meaningful results obtained, could spur initiatives to further regulate hydraulic fracturing under the federal SDWA or other regulatory mechanisms. Moreover, there have been public concerns expressed about naturally occurring radioactive materials being detected in flow back water resulting from hydraulic fracturing, particularly in the Marcellus Shale area. This concern could result in further regulation in the treatment, storage, handling and discharge of flow back water generated from these activities that, if implemented, could limit drilling or increase the costs of drilling in affected regions. 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

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excess liability insurance policies would cover third-party claims related to hydraulic fracturing operations and associated legal expenses in accordance with, and subject to, the terms of such policies.

Air Emissions

The Clean Air Act, as amended (“CAA”), and comparable state laws and regulations govern emissions of various air pollutants through air emissions standards, construction and operating permit programs and the imposition of other compliance requirements. Air emissions from some equipment found at our operations or other operations in which we own an interest, such as gas compressors, are potentially subject to regulations under the CAA or equivalent state and local regulatory programs, although many small air emission sources are expressly exempt from such regulations. To the extent that these air emissions are regulated, they are generally regulated by permits issued by state regulatory agencies. While the need to obtain permits has the potential to delay the development of oil and natural gas projects, to date, we believe that no unusual difficulties have been encountered in obtaining air permits. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. For example, on August 16, 2012, the EPA published final rules under the CAA that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards (“NSPS”) and National Emission Standards for Hazardous Air Pollutants (“NESHAP”) programs. With regards to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from three subcategories of fractured and re-fractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non-wildcat and non-delineation gas wells; and all “other” fractured and re-fractured gas wells. All three subcategories of wells must route flow back emissions to a gathering line or be captured and combusted using a combustion device such as a flare after October 15, 2012. However, the “other” wells must use reduced emission completions, also known as “green completions,” with or without combustion devices, after January 1, 2015. These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, effective October 15, 2012 and from pneumatic controllers and storage vessels, effective October 15, 2013. We are currently reviewing this new rule and assessing its potential impacts on our operations. Compliance with these requirements could increase our costs of development and production, which costs could be significant.

Climate Change

In response to findings made by the EPA in December 2009 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 certain large stationary sources that are potential major sources of GHG emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet “best available control technology” standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified facilities. In addition, the EPA adopted rules requiring the monitoring and reporting of GHGs from certain sources in the United States, including, among others, onshore and offshore oil and natural gas production facilities, which include certain of our operations, on an annual basis. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations. Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations that require reporting of GHGs or otherwise limits emissions of GHGs from our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations or could adversely affect demand for the oil and natural gas that we produce. 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 effects were to occur, they could have an adverse effect on our exploration and production interests and operations.

Endangered Species Act

The federal Endangered Species Act, as amended (“ESA”), and similar state laws and other regulatory initiatives restrict activities that may affect endangered or threatened species or their habitats. While some of our operations may be located in or

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near areas that are designated as habitat for endangered or threatened species, we believe that we are in substantial compliance with the ESA. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts to protected species, and we may be prohibited from conducting operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to our activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing of more than 250 species as endangered or threatened under the ESA before the completion of the agency's 2017 fiscal year. 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.

Worker Safety and Health

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

Operations on Federal Lands

Performance of oil and gas exploration and production activities on federal lands, including Indian lands and lands administered by the federal Bureau of Land Management (“BLM”), may be subject to the National Environmental Policy Act, as amended (“NEPA”). NEPA requires federal agencies, including the BLM and the federal Bureau of Indian Affairs, to evaluate major agency actions, such as the issuance of permits that have the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. Our current and proposed exploration and production activities upon federal lands require governmental permits that are subject to the requirements of NEPA. We are not planning any drilling operations on BLM leased acreage in 2013. 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. Also, 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, transportation, storage and disposal of naturally occurring radioactive materials. Furthermore, owners, lessees and operators of natural gas and oil properties are also subject to increasing civil liability brought by surface owners and adjoining property owners. Such claims are predicated on the damage to or contamination of land resources occasioned by drilling and production operations and the products derived there from and are often based on negligence, trespass, nuisance, strict liability or fraud.

Industry Segment and Geographic Information

We operate in one industry segment, which is the exploration, development and production of natural gas and oil in the U.S. Our current operational activities are conducted primarily in and our consolidated revenues are primarily generated from markets exclusively in the U.S.

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 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 now required to file such disclosure on SEDAR as soon as practicable after such disclosure is filed with the SEC.

Insurance Matters

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

We maintain insurance at industry customary levels to limit our financial exposure in the event of a substantial environmental claim resulting from sudden, unanticipated and accidental discharges of certain prohibited substances into the environment. Such insurance might not cover the complete amount of such a claim and would not cover fines or penalties for a violation of an environmental law nor would it cover a gradual pollution loss. In analyzing our operations and insurance needs, and in recognition that we have a large number of individual well locations with varied geographical distribution, we compared premium costs to the likelihood of material loss of production. Based on this analysis, we have elected, at this time, not to carry loss of production or business interruption insurance for our operations. 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.-The process of drilling for and producing natural gas and oil 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, 2013, we had 41 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 natural gas and oil. 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.

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 Ethics;
- Corporate Governance Guidelines;
- Audit Committee Charter;
- Nominating and Governance Committee Charter:
- Compensation Committee Charter;
- Reserves Review Committee Charter; and

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- 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 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.

Risks Related to Our Business

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, we have not been profitable since we started our business. We incurred net losses of $160.9 million, $1.8 million and $12.5 million for the years ended December 31, 2012, 2011 and 2010, respectively. Our capital has been employed in an increasingly expanding natural gas and oil exploration and development program, with our focus on finding significant natural gas and oil reserves and producing from them over the long-term rather than focusing on achieving immediate net income. The uncertainties described in this "Item 1A – Risk Factors" and elsewhere in this Form 10-K may impede our ability to ultimately find, develop and exploit natural gas and oil reserves. Our failure to achieve profitability in the future could materially adversely affect our ability to raise additional capital and continue our exploration and development program.

Natural gas, condensate, oil and NGLs prices are volatile and further declines in natural gas, condensate, oil and NGLs prices would continue to significantly and negatively affect our financial condition and results of operations. Additionally, our results are subject to commodity price fluctuations related to seasonal and market conditions and reservoir and production risks.

The success of our business depends primarily on the market prices of natural gas, condensate, oil and NGLs. Natural gas and oil commodity prices are set by broad market forces, which have been and will likely continue to be volatile in the future. For example, market prices for natural gas in the U.S. have declined substantially from 2008 price levels, and the rapid development of shale plays throughout North America has contributed significantly to this trend. Additionally, market prices for NGLs declined subsequent to 2011 and we experienced a 46% decrease in our realized NGLs prices per barrel from 2011 to 2012. Lower prices also may reduce the amount of natural gas, condensate, oil or NGLs that we can produce economically. Prices for natural gas, condensate, oil and NGLs are subject to wide fluctuations in response to relatively minor changes in the supply of and demand for natural gas, condensate, oil or NGLs, market uncertainty and a variety of additional factors that are beyond our control. These factors include:

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

The long-term effect of these and other factors on the prices of natural gas, condensate, oil 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;

- Reducing the amount of natural gas, condensate, oil and NGLs that we can produce economically;
- Causing us to delay or postpone some of our capital projects;

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- Reducing our revenues, operating income or cash flows;
- Reducing the amounts of our estimated proved natural gas and oil reserves;
- Reducing the carrying value of our natural gas and oil properties;
- Reducing the standardized measure of discounted future net cash flows relating to natural gas and oil reserves; and
- Limiting our access to sources of capital, such as equity and long-term debt.

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

Regional natural gas, condensate, oil 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 2012, approximately 47% of our natural gas production was priced based on the Katy Hub basis point and 52% was priced based on the Columbia Gas Appalachia Pool. Continued reduced prices for natural gas have compelled us to limit our drilling operations in our Hilltop area and to focus on lease maintenance. Our West Virginia natural gas production is priced using the Columbia Gas Appalachia Pool. At December 31, 2012, the Henry Hub price was $2.76 per MMBtu, compared to our key basis point pricing of $2.77 per MMBtu at the Katy Hub and $2.77 per MMBtu for the Columbia Gas Appalachia Pool. Low natural gas prices in any or all of the areas where we operate would negatively impact our financial condition and results of operations. During 2012, approximately 9% and 91% of our condensate and oil production was produced in East Texas and the Marcellus Shale, respectively, where we realized $95.71 and $62.40 per barrel for the year, respectively. This compares to the 12-month unweighted average WTI posted price of $92.71 per barrel at December 31, 2012. For the year ended December 31, 2012, our realized NGLs prices for Marcellus Shale NGLs production represented approximately 30% of the 12-month unweighted average WTI posted price of $92.71.

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

The natural gas and oil industry is capital intensive. We make and expect to continue to make substantial growth capital expenditures in our business for the development, production and acquisition of natural gas and oil reserves. These expenditures will reduce the amount of cash available for distribution to our preferred stockholders. Our capital budget for 2013 totals $92.8 million, and we expect to fund using existing cash balances, cash generated internally from our operations, additional borrowings under our Revolving Credit Facility (as defined herein), the possible divestiture of assets, the possible issuance of debt or preferred equity securities or some combination thereof.

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

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

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

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

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

We have entered into New York Mercantile Exchange ("NYMEX") futures contracts as hedges on approximately 7.4 Bcf of natural gas production, 146,000 Bbls of crude production and 110,000 Bbls of NGLs production in 2013 and 4.7 Bcf of natural gas production and 73,000 Bbls of crude production in 2014 as of December 31, 2012. Although these hedges may partially protect us from declines in commodity prices, the use of these arrangements also may limit our ability to benefit from significant increases in the prices of natural gas, condensate, oil and NGLs.

Approximately 37% of our proved reserves are classified as proved developed non-producing or proved undeveloped and may ultimately prove to be less than estimated.

At December 31, 2012, approximately 37% of our total proved reserves were classified as proved developed non-producing or proved undeveloped. It will take substantial capital to recomplete or drill our non-producing and undeveloped locations. Our estimate of proved reserves at December 31, 2012 assumes that we will spend significant development capital expenditures to develop these reserves, including an estimated $27.0 million and $34.0 million in 2013 and 2014, 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.

Approximately 71% of our natural gas, condensate, oil and NGLs revenues before impact of realized hedges and 85% of our total proved reserves as of and for the year ended December 31, 2012 were attributable to our properties in the Appalachian Basin. Any disruption in production, development of proved reserves, or our ability to process and sell natural gas from this area 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. Production in the Appalachian Basin could unexpectedly be disrupted or curtailed due to reservoir, mechanical or third-party gathering system 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. If the purchaser's or third-party gathering system facilities ceased to operate, were destroyed or otherwise needed replacement, it could require 60 to 90 days to replace or repair these facilities. A 60 to 90 day curtailment of our total Marcellus Shale production could reduce current revenues by an estimated $7.4 million to $11.1 million, before the impact of hedges, with a corresponding reduction in our cash flow. Moreover, an unexpected delay in developing proved reserves in this area due to capital constraints or changes in development plan could reduce future revenues.

Approximately 27% of our natural gas, condensate, oil and NGLs revenues before impact of realized hedges and 15% of our total proved reserves as of and for the year ended December 31, 2012 were attributable to our properties in East Texas. Any disruption in production, development of proved reserves, or our ability to process and sell natural gas from this area would have a material adverse effect on our results of operations or reduce future revenues.

Production of the natural gas in East Texas could unexpectedly be disrupted or curtailed due to reservoir or mechanical problems. Our natural gas produced from this area contains levels of carbon dioxide and hydrogen sulfide that are above levels accepted by gas purchasers. This production must be treated by the purchaser. A majority of our East Texas production is processed by the purchaser. If the purchaser's facilities ceased to operate, were destroyed or otherwise needed replacement, it could require 60 to 90 days to replace or repair these facilities. A 60 to 90 day curtailment of our total East Texas production could reduce current revenues by an estimated $2.1 million to $3.2 million, before the impact of hedges, with a corresponding reduction in our cash flow. Moreover, an unexpected delay in developing proved reserves in this area due to capital constraints or changes in development plan could reduce future revenues.

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

The availability of a ready market for our natural gas, condensate, oil and NGLs production, particularly in the Appalachian Basin area, depends on the proximity of our reserves to and the capacity of natural gas gathering 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 Shale in the Appalachian area of West Virginia and central and southwestern Pennsylvania and in the Hilltop area in East Texas. For the year ended December 31, 2012, SEI accounted for substantially all of our revenues from the Marcellus Shale and ETC accounted for substantially all of our revenues from the Hilltop area in East Texas. If SEI were to cease purchasing and Williams were to cease transporting our natural gas in the Marcellus Shale and if ETC were to cease purchasing and transporting our natural gas

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in the Hilltop area of East Texas and we were unable to contract with another purchaser and/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 the 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. For example, our Marcellus Shale production for 2012 was significantly impacted by issues with high line pressures on the third-party operated gathering system. In West Virginia and southwestern Pennsylvania, key issues to development include limited pipeline infrastructure and access, water access and disposal issues to support operations and limited industry services. All of these factors could have an adverse effect on our ability to effectively conduct exploration and development activities.

Further, interstate transportation and distribution of natural gas is regulated by the federal government through the FERC. FERC sets rules and carries out administratively the oversight of interstate markets for natural gas and other energy policy. Additionally, state regulators have powers over sale, supply and delivery of natural gas and oil 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.

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

Our future natural gas, condensate, oil 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 natural gas and oil 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 natural gas and oil reserves would be impaired to the extent cash flow from operations is reduced and external sources of capital become limited or unavailable. Further, we may not be successful in exploring for, developing or acquiring additional reserves, which could have a material adverse effect on our financial condition, future cash flows and the results of operations.

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

Our future success will largely depend on the success of our exploration drilling program. Participation in exploration drilling activities involves numerous risks, including the risk that no commercially productive natural gas or oil 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 damage;
- Pressure or irregularities in formations;
- Environmental hazards, such as natural gas leaks, crude oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the environment;
- Uncontrollable flows of natural gas, oil, brine water or drilling fluids;
- Equipment failures or accidents;
- Adverse weather conditions;
- Compliance with governmental requirements and laws, present and future; 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.

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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 natural gas and oil 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 natural gas and oil 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 natural gas or oil reserves and of future net cash flows necessarily depend on many variables and assumptions, such as:

- Historical natural gas or oil 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 operating costs;
- Assumptions concerning severance and excise taxes; and
- Assumptions concerning development costs and workover and remedial costs.

Any of these variables or assumptions could vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of natural gas or oil 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. For 2012, 2011, 2010 and 2009, the estimated discounted future net cash flows from proved reserves 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 natural gas or oil;
- Actual prices received for natural gas in the future being different than those used in the estimate;
- Curtailments or increases in consumption of natural gas or oil;
- Changes in governmental regulations or taxation; and
- The timing of both production and expenses in connection with the development and production of natural gas or oil properties.

In this Form 10-K, the net present value of estimated future net revenues at December 31, 2012 is calculated using the 12-month unweighted arithmetic average of the first-day-of-the-month price and a 10% discount rate. This price and 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 natural gas and oil 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 natural gas and oil 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 gas properties that can be capitalized on our balance sheet. We may experience write downs of the carrying value of our oil and gas properties in the future if the present value of our proved natural gas and oil reserves is lower than our remaining unamortized capitalized costs. If the net capitalized costs of our oil and 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

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carrying value of oil and natural gas properties increases when natural gas and crude oil prices are depressed or volatile. 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.

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

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

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

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

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

As of December 31, 2012, 13 gross (3.1 net) wells in which we have an interest were operated by other companies.

Our inability to meet a financial covenant contained in the Revolving Credit Facility may adversely affect our liquidity, financial condition or results of operations.

We are subject to certain financial covenants which we are required to maintain under the Revolving Credit Facility related to our working capital, cash flow and interest coverage ratio. Breach of such financial covenants may constitute an event of default. At December 31, 2012, we were not in compliance with the working capital ratio contained in the Revolving Credit Facility and obtained a waiver from our lenders. In the future, if we breach a financial covenant and we are unable to cure such violation or obtain waivers from our lenders under the Revolving Credit Facility within the applicable cure periods, such violation will constitute an event of default under the Revolving Credit Facility, and our lenders could terminate any commitments they have to make available further funds, accelerate the due dates for the payments of all outstanding indebtedness and exercise their remedies as a secured creditor with respect to the collateral securing the Revolving Credit Facility, which is substantially all of our natural gas and oil properties.

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 natural gas price risk with counterparties. If our counterparties fail or refuse to honor their obligations under these derivative instruments, our hedges of the related risk will be ineffective. This is a more pronounced risk to us in view of the recent stresses suffered by financial institutions. We cannot provide assurance that our counterparties will honor their obligations now or in the future. A counterparty's insolvency or inability or unwillingness to make payments required under terms of derivative instruments with us could have a material adverse effect on our financial condition and

results of operations. At the date of filing of this Form 10-K, our counterparties were BP Corporation North America Inc., Bank of Montreal, EDF Trading North America, LLC., Shell Energy North America (US) L.P. and Wells Fargo Bank, N.A.

We are subject to various legal proceedings and claims. The cost of defending these lawsuits and any future lawsuits and any resulting judgments could be significant and could have a material adverse effect upon our financial condition.

We are subject to various significant legal proceedings and claims arising outside of the normal course of business. No assurance can be given regarding the outcome of these legal proceedings, and additional claims may arise. We are vigorously defending the Company in these matters. This 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 related to these matters have been incurred to date and significant expenditures may continue to be incurred in the future. Although we cannot predict the ultimate outcome of these matters or the liability that could potentially result, continuing defense costs and any adverse outcome could adversely affect our business, financial condition and results of operations. For more information on our significant currently outstanding legal proceedings, see Note 15, "Commitments and Contingencies Litigation", to our consolidated financial statements included in this Form 10-K.

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

Our practice in acquiring exploration leases or undivided interests in natural gas and oil 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 currently are involved in a title litigation matter in East Texas. See Note 15, "Commitments and Contingencies – Litigation," to our consolidated financial statements included in this Form 10-K.

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 natural gas and oil exploration and production interest and operations are subject to stringent and complex federal, state, regional and local laws and regulations relating to the operation and maintenance of our facilities, including laws regulating removal of natural resources from the ground, the discharge of materials into the environment and otherwise relating to environmental protection. Natural gas and oil 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 regulations require various timely permits, including drilling and environmental permits, before conducting regulated activities and we cannot assure you that such permits will be received. The failure or delay in obtaining the requisite approvals or permits may adversely affect our business, financial condition and results of operations. Additionally, these laws and regulations impose numerous obligations and restrictions that are applicable to our interests and operations including, but not limited to:

- 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

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•Other regulatory controls on operating activities.

In addition, regulatory agencies have from time to time imposed price controls and limitations on production by restricting the flow rate of wells below actual production capacity in order to conserve supplies of natural gas and oil. Failure to comply with these laws and regulations applicable to our interests and operations could result in the assessment of administrative, civil and criminal penalties, the imposition of investigatory or remedial obligations and the issuance of orders enjoining or limiting some or all of our operations, any of which could have a material adverse effect on our financial condition. Legal requirements are sometimes unclear or subject to reinterpretation and may be amended in response to economic or political conditions. As a result, it is hard to predict the ultimate future cost of compliance with these requirements or their effect on our interests and operations. In addition, existing laws or regulations, as currently interpreted or reinterpreted in the future, or future laws or regulations may have a material adverse effect on our financial condition, future cash flows and the results of operations.

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 natural gas and oil wells and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, 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 gas commissions, but the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel fuels and published draft permitting guidance in May 2012 addressing the performance of such activities using diesel fuels. In November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing and the agency currently plans to issue a Notice of Proposed Rulemaking that would seek public input on the design and scope of such disclosure regulations

. In addition, Congress has from time to time considered legislation to provide for federal regulation of hydraulic fracturing under the SDWA and to require disclosure of the chemicals used in the hydraulic fracturing process. At the state level, some states, including 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. 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 have been conducted or 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. The EPA has commenced a study of the potential environmental effects of hydraulic fracturing activities, with a first progress report outlining work currently underway by the agency released on December 21, 2012 and a final report drawing conclusions about the potential impacts of hydraulic fracturing on drinking water resources expected to be available for public comment and peer review by 2014. In addition, the U.S. Department of Energy and the U.S. Department of the Interior have studied or are studying different aspects of hydraulic fracturing. These studies, depending on their results, could spur initiatives to regulate hydraulic fracturing under the SDWA or under newly established legislation.

We could incur significant costs and liabilities in responding to contamination that occurs as a result of our operations.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations or in operations in which we own a working interest as a result of the handling of petroleum hydrocarbons and wastes, because of air emissions and wastewater discharges related to operations, and due to historical industry operations and waste disposal practices. Under certain environmental laws and regulations, we could be subject to strict, joint and several liabilities for the removal or remediation of previously released materials or property contamination. Private parties, including the owners of properties upon which our wells or the wells in which we own a working interest are drilled and facilities where our petroleum hydrocarbons or wastes are taken for reclamation or disposal, also may have the right to pursue legal actions to enforce compliance as well as to seek damages for non-compliance with environmental laws and regulations or for personal injury or property or natural resource damages. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly well drilling, construction, completion or water management activities, or waste , handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain

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compliance and may otherwise have a material adverse effect on our own results of operations, competitive position or financial condition.

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

The natural gas and oil 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 discharge of brine, toxic gases or well fluids.

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

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

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

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

The President of the United States' budget proposal for the fiscal year 2013 recommended the elimination of certain key U.S. federal income tax preferences currently available to oil and gas exploration and production companies. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for U.S. production activities for oil and natural gas production, and (iv) the extension of the amortization period for certain geological and geophysical expenditures.

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

Our natural gas and oil 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 natural gas and oil and any related hedging activities that we undertake, we are required to observe the market-related regulations enforced by these agencies, which hold substantial

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enforcement authority. Our sales may also be subject to certain reporting and other requirements. Failure to comply with such regulations, as interpreted and enforced, could have a material adverse effect on our business, results of operations, financial condition and our ability to make cash distributions to our unitholders.

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

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

On July 21, 2010 new comprehensive financial reform legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), was enacted that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, including us, that participate in that market. The Dodd-Frank Act requires the CFTC, the SEC and other regulators to promulgate rules and regulations implementing the new legislation. In its rulemaking under the Dodd-Frank Act the CFTC has issued final regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. Certain bona fide hedging transactions would be exempt from these position limits. The position limits rule was vacated by the United States District Court for the District of Colombia in September of 2012 although the CFTC has stated that it is appealing the District Court's decision. The CFTC also has finalized other regulations, including critical rulemakings on the definition of "swap", "security-based swap", "swap dealer" and "major swap participant". The Dodd-Frank Act and CFTC Rules also may require us in connection with certain derivatives activities to comply with clearing and trade-execution requirements (or take steps to qualify for an exemption to such requirements). In addition new regulations may require us to comply with margin requirements although these regulations are not finalized and their application to us is uncertain at this time. Other regulations also remain to be finalized, and the CFTC recently has delayed the compliance dates for various regulations already finalized. As a result it is not possible at this time to predict with certainty the full effects of the Dodd-Frank Act and CFTC rules on us and the timing of such effects. The Dodd-Frank Act also may require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty.

The Dodd-Frank Act and any new regulations could significantly increase the cost of derivatives contracts (including from swap recordkeeping and reporting requirements and through requirements to post collateral which could adversely affect our available liquidity), materially alter the terms of derivatives contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivatives contracts, and increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Finally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity 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. 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.

In response to findings made by the EPA in December 2009 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 certain large stationary sources that are potential major sources of GHG emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis. In addition, the EPA adopted rules requiring the monitoring and reporting of GHGs from certain sources in the United States, including, among others, onshore and offshore oil and natural gas production facilities while Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products. 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. Finally, it should be noted that some scientists have concluded that increasing concentrations of

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greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our assets and operations.

Competition in the natural gas and oil 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 natural gas and oil companies in all areas of our operations, including the acquisition of exploratory prospects and proven properties. Our competitors include major integrated natural gas and oil companies, numerous independent natural gas and oil 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 natural gas and oil business for a much longer time than we have. These companies may be able to pay more for exploratory prospects and productive natural gas and oil 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 natural gas and oil companies. Our ability to explore for natural gas and oil 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.

Acquisition prospects are difficult to assess and may pose additional risks to our operations.

Where appropriate, we may evaluate and pursue acquisition opportunities on terms our management considers favorable. The successful acquisition of natural gas and oil properties requires an assessment of:

- Recoverable reserves;
- Exploration potential;
- Future natural gas and oil prices;
- Operating costs;
- Potential environmental and other liabilities; and
- Permitting and other environmental authorizations required for our operations.

In connection with such an assessment, we would expect to perform a review of the subject properties that we believe to be generally consistent with industry practices. Nonetheless, the resulting conclusions are inexact and their accuracy inherently uncertain, and such an assessment may not reveal all existing or potential problems, nor will it necessarily permit a buyer to become sufficiently familiar with the properties to fully assess their merits and deficiencies. Inspections may not always be performed on every facility or well, and structural and environmental problems are not necessarily observable even when an inspection is undertaken. Future acquisitions could pose additional risks to our operations and financial results, including:

- Problems integrating the purchased operations, personnel or technologies;
- Unanticipated costs;
- Diversion of resources and management attention from our exploration business;
- Entry into regions or markets in which we have limited or no prior experience; and
- Potential loss of key employees, particularly those of the acquired organization.

Technological changes could affect our operations.

The natural gas and oil 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 natural gas and oil 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.

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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 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 United States 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.
Risks Related to Our Common Shares
Our common share price has been and is likely to continue to be highly volatile.
The trading price of our common shares are 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 natural gas and oil 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 shares 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 natural gas and oil exploration companies. If this type of litigation were instituted against us following a period of volatility in our common shares trading price, it could result in substantial costs and a diversion of our management’s attention and resources, which could have a material adverse effect on our financial condition, future cash flows and the results of operations.
Future issuances of our common shares may adversely affect the price of our common shares.
The future issuance of a substantial number of common shares into the public market, or the perception that such an issuance could occur, could adversely affect the prevailing market price of our common shares. A decline in the price of our common shares could make it more difficult to raise funds through future offerings of our common shares or securities convertible into common shares.
Our ability to issue an unlimited number of our common shares under our articles of incorporation may result in dilution or make it more difficult to effect a change in control of the Company, which could adversely affect the price of our common shares.
Unlike most corporations formed in the U.S., our Amended and Restated Articles of Incorporation chartered under the laws of the Province of Alberta, Canada permit the board of directors to issue an unlimited number of new common shares without shareholder approval, subject only to the rules of the NYSE MKT or any future exchange on which our common shares might trade. The issuance of a large number of common shares could be effected by our directors to thwart a takeover attempt or offer for us by a third party, which could result in the common shares being valued less in the market. The issuance or the threat of issuance of a large number of common shares at prices that are dilutive to the outstanding common shares could also result in the common shares being valued less in the market.
We are able to issue shares of preferred stock with greater rights than our common shares.
Our Amended and Restated Articles of Incorporation authorize our board of directors to issue one or more series of preferred shares and set the terms of the preferred shares without seeking any further approval from our shareholders. Any preferred shares that are issued may rank ahead of our common shares in terms of dividends, liquidation rights, or

voting rights. If we issue preferred shares, it may adversely affect the market price of our common shares.

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Because we have no plans to pay dividends on our common shares, shareholders must look solely to appreciation of our common shares to realize a gain on their investment.

We do not anticipate paying any dividends on our common shares in the foreseeable future. We currently intend to retain any future earnings to finance the expansion of our business. In addition, 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, shareholders must look solely to appreciation of our common shares to realize a gain on their investment, which may not occur.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Our properties consist primarily of natural gas and oil leases in the following areas:

- Marcellus Shale in West Virginia and central and southwestern Pennsylvania;
- Mid-Continent area of the U.S.; and
- Hilltop area of East Texas.

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 per Mcfe associated with our sales of natural gas, condensate and oil and NGLs for the periods indicated. Condensate, oil and NGLs are compared with natural gas in terms of cubic feet of natural gas equivalents. One barrel of condensate, oil or NGLs is the energy equivalent of six Mcf of natural gas. Unless otherwise specified, all production volumes in this Annual Report on 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,		
	2012	2011	2010
Production:			
Natural gas (MMcf)	10,564	7,318	7,593
Condensate and oil (MBbl)	177	40	10
NGLs (MBbl)	270	21	—
Total production (MMcfe)	13,247	7,684	7,654
Daily Production:			
Natural gas (MMcf/d)	28.9	20.0	20.8
Condensate and oil (MBbl/d)	0.5	0.1	—
NGLs (MBbl/d)	0.7	0.1	—
Total daily production (MMcfe/d)	36.2	21.1	21.0
Average sales price per unit:			
Natural gas per Mcf, excluding impact of realized hedging activities	$2.21	$3.21	$3.51
Natural gas per Mcf, including impact of realized hedging activities	3.20	4.56	4.06
Condensate and oil per Bbl, excluding impact of realized hedging activities	65.45	85.11	72.63
Condensate and oil per Bbl, including impact of realized hedging activities	70.01	85.11	72.63
NGLs per Bbl, excluding impact of realized hedging activities	28.22	52.47	—
NGLs per Bbl, including impact of realized hedging activities	34.40	52.47	—
Average sales price per Mcfe, excluding impact of realized hedging activities	3.21	3.65	3.58
Average sales price per Mcfe, including impact of realized hedging activities	4.19	4.93	4.12
Selected operating expenses (in thousands):			
Production taxes	$2,269	$620	$370
Lease operating expenses	6,174	8,630	6,679
Transportation, treating and gathering	4,965	4,501	4,654
Depreciation, depletion and amortization	25,424	15,216	9,306
Impairment of natural gas and oil properties	150,787	—	—
General and administrative expense	12,211	11,365	14,638
Selected operating expenses per Mcfe:			
Production taxes	$0.17	$0.08	$0.05
Lease operating expenses	0.47	1.12	0.87
Transportation, treating and gathering	0.37	0.59	0.61
Depreciation, depletion and amortization	1.92	1.98	1.22
General and administrative expense	0.92	1.48	1.91
Production costs (1)	0.80	1.62	1.39

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

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Drilling Activity

The following table shows our drilling activity for the periods indicated. In the table, “gross” refers to wells in which we have a working interest, and “net” refers to gross wells multiplied by our working interest in such wells.

	For the Years Ended December 31,					
	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Exploratory wells:						
Productive	6.0	1.7	20.0	11.9	2.0	2.0
Non-productive	—	—	—	—	—	—
Total	6.0	1.7	20.0	11.9	2.0	2.0
Development wells:						
Productive	31.0	14.2	5.0	1.7	3.0	2.2
Non-productive	—	—	—	—	—	—
Total	31.0	14.2	5.0	1.7	3.0	2.2

On December 31, 2012, we had a total of 15 gross (7.5 net) operated wells in the process of being drilled or awaiting fracture stimulation in the Marcellus Shale and two gross (1.0 net) non-operated wells being drilled in the Mid-Continent.

Exploration and Development Acreage

The following table sets forth our ownership interest in undeveloped and developed acreage in the areas indicated where we own a working interest as of December 31, 2012. The term “gross” represents the total number of acres in which we own a working interest. The term “net” represents our proportionate working interest resulting from our ownership in gross acres.

	Undeveloped Acreage		Developed Acreage	
	Gross	Net	Gross	Net
Marcellus Shale area, West Virginia and Pennsylvania (1)				
Marcellus West	41,272	18,256	5,650	2,659
Marcellus East	57,538	51,398	3,185	2,842
Total Marcellus Shale area	98,810	69,654	8,835	5,501
Hilltop area, East Texas	22,041	10,535	10,966	6,475
Mid-Continent	41,329	16,959	607	304
Total	162,180	97,148	20,408	12,280

(1) We believe that substantially all of our Marcellus Shale acreage is prospective. The Marcellus West acreage reflects that Atinum has earned their full joint venture interest.

Undeveloped Acreage Expirations

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

As of December 31,	Marcellus Shale				Total Expiring	% of Total Undeveloped	
	West	East	Hilltop Area, East Texas	Mid-Continent	Gross Acres	Gross Acres	
2013	19,108	6,998	16,888	2,289	45,283	28	%
2014	1,530	10,081	4,803	2,899	19,313	12	%
2015	7,960	11,356	—	36,141	55,457	34	%
2016	6,790	13,969	350	—	21,109	13	%
2017 and thereafter	5,456	52	—	—	5,508	3	%

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

As of December 31,	Marcellus Shale West	Marcellus Shale East	Hilltop Area, East Texas	Mid-Continent	Total Expiring Net Acres	% of Total Undeveloped Net Acres
2013	9,170	6,710	6,026	993	22,899	24 %
2014	624	9,894	4,415	1,514	16,447	17 %
2015	3,469	9,236	66	14,452	27,223	28 %
2016	2,574	13,824	28	—	16,426	17 %
2017 and thereafter	2,317	52	—	—	2,369	2 %

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 natural gas and oil 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. Of the 22,899 net acres expiring in 2013, we are currently focusing on net acres expiring in Marcellus West, Mid-Continent and East Texas. In Marcellus West, we anticipate drilling on the majority of the acreage before it expires. In Mid-Continent, we plan to extend the leases for the majority of acreage expiring during 2013 and if we are not able to extend the lease, the acreage will expire. In East Texas, we are in the process of extending approximately 3,500 acres that expire in 2013. With respect to the remaining 2,526 acres in East Texas scheduled for expiration in 2013, we may try to renew expiring leases if prospective economics improve and funds are available, or otherwise we will allow the remaining East Texas acreage to expire. Our current plans in Marcellus East are to let approximately 6,710 net acres scheduled for expiration in 2013 expire. During 2010, we drilled 16 wells in shallower Devonian formations in the Appalachia area. These wells allow us to retain, for the life of production of our interest, certain undeveloped acreage above the Marcellus Shale for possible deeper drilling in the future. We do not expect to lose significant lease acreage in the Marcellus Shale as a result of our failure to drill or our reduction in drilling activities due to declines in natural gas prices. We may also allow additional acreage to expire in the future.

Productive Wells

The following table sets forth our working interest ownership in productive wells in the areas indicated as of December 31, 2012. 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 natural gas or oil. 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
Appalachia, West Virginia and Pennsylvania	89.0	47.5	—	—	89.0	47.5
Hilltop area, East Texas	22.0	14.9	15.0	10.8	37.0	25.7
Mid-Continent	—	—	1.0	0.5	1.0	0.5
Total	111.0	62.4	16.0	11.3	127.0	73.7

Natural Gas and Oil Reserves

Reserve Estimation

The SEC rules expand the definition of natural gas and oil 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. 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.

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Third Party Review of Reserves Estimates

For the years ended December 31, 2012 and 2011, reserves estimates for the Marcellus Shale 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 the Marcellus Shale. Additionally, for the year ended December 31, 2012, Wright evaluated the reserves estimates for the Mid-Continent shown herein. Wright was founded in 1988 and performs consulting petroleum engineering services. A copy of Wright's summary reserve report is included as Exhibit 99.2 to this Form 10-K. For the years ended December 31, 2012, 2011 and 2010, reserves estimates for the Hilltop Area of East Texas shown herein have been independently evaluated by Netherland, Sewell & Associates, Inc. ("NSAI"), a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI evaluated the reserves estimates for the Powder River Basin of Wyoming and Montana for the years ended December 31, 2011 and 2010. Our working interest in the Powder River Basin was assigned to the operator effective January 1, 2012. Additionally, NSAI evaluated the reserves estimates for the Marcellus Shale for the year ended December 31, 2010. NSAI was founded in 1961 and performs consulting petroleum engineering services. A copy of NSAI'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 39 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.

Within NSAI, the technical persons primarily responsible for preparing the reserves estimates set forth in the NSAI reserve report incorporated herein are Mr. Dan Paul Smith and Mr. William (Bill) J. Knights. Mr. Smith has been practicing consulting petroleum engineering at NSAI since 1980. He is a Registered Professional Engineer in the State of Texas and has over 31 years of practical experience in petroleum engineering and in the estimation and evaluation of reserves. He graduated from Mississippi State University in 1973 with a Bachelor of Science Degree in Petroleum Engineering. Mr. Knights has been practicing consulting petroleum geology at NSAI since 1991. He is a Certified Petroleum Geologist and Geophysicist in the State of Texas and has over 31 years of practical experience in petroleum geosciences, with over 20 years of experience in the estimation and evaluation of reserves. He graduated from Texas Christian University in 1981 with a Bachelor of Science Degree in Geology and in 1984 with a Master of Science Degree in Geology. Both technical principals meet or exceed 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; both are 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 and NSAI to ensure the integrity, accuracy and timeliness of data furnished to Wright and NSAI in their reserve review and estimation process. Throughout the year, our internal technical team meets regularly with representatives of Wright and NSAI to review properties and discuss methods and assumptions used in Wright and NSAI's preparation of the year-end reserves estimates. We provide historical information to Wright and NSAI for our largest producing properties, including with respect to ownership interest, oil and gas production, well test data, commodity prices and operating and development costs. Wright and NSAI perform 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 and NSAI's estimates have 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 and NSAI reserve reports are reviewed by the reserves review committee, together with representatives of Wright, NSAI and our internal team.

Since 2006, all of our reserve 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

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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, 2012 included in this Form 10-K was estimated by Wright and NSAI using standard engineering and geosciences procedures and methods used in the petroleum industry. The technical personnel responsible for preparing the reserve estimates at Wright and NSAI 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, 2012 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 natural gas prices utilized were the Henry Hub price of $2.76 per MMBtu, the Katy Hub price of $2.77 per MMBtu and the Columbia Gas Appalachia Pool price of $2.77 per MMBtu. NSAI utilized a West Texas Intermediate ("WTI") posted oil price of $91.21 per barrel, and Wright utilized a WTI spot oil price of $94.71 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 natural gas and oil prices, which have fluctuated significantly in recent years. All of our proved reserves are located onshore within the United States.

The following table summarizes our estimated proved reserves as of December 31, 2012:

	Total Proved Reserves			
	Producing	Non-producing	Undeveloped	Total
Natural gas (MMcf)	85,728	9,873	35,409	131,010
NGLs (MBbls)	3,042	174	1,706	4,922
Condensate and oil (MBbls)	1,801	158	1,435	3,394
Total proved reserves (MMcfe)	114,781	11,872	54,256	180,909
PV-10 (in thousands) (1)	$154,291	$13,451	$39,067	$206,809

(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. We presently have approximately

$254.3 million of net operating loss carryforwards, $50.6 million of foreign tax credit carryforwards and $211.1 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 as of December 31, 2012 is $206.8 million.

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The following table summarizes our proved reserves by geographic area as of December 31, 2012:
SEC Pricing Case Proved Reserves (1)

	Natural Gas (MMcf)	NGLs (MBbls)	Condensate and Oil (MBbls)	MMcfe	% Proved Developed	PV-10 (2) (in thousands)
Appalachia, West Virginia and Pennsylvania	103,588	4,922	3,341	153,174	65 %	$ 191,910
Hilltop area, East Texas	27,356	—	16	27,449	100 %	12,786
Mid-Continent	43	—	37	262	100 %	2,079
Other	23	—	—	24	100 %	34
Total	131,010	4,922	3,394	180,909	70 %	$ 206,809

(1) Key natural gas prices utilized were the Henry Hub price of $2.76 per MMBtu, the Katy Hub price of $2.77 per MMBtu and the Columbia Gas Appalachia Pool price of $2.77 per MMBtu. NSAI utilized a WTI posting oil price of $91.21 per barrel and Wright utilized a WTI spot oil price of $94.71 per barrel.

(2) 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. We presently have approximately $254.3 million of net operating loss carryforwards, $50.6 million of foreign tax credit carryforwards and $211.1 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 as of December 31, 2012 is $206.8 million.

Proved Undeveloped Reserves (“PUDs”)

As of December 31, 2012, our PUDs totaled 54.3 Bcfe, representing a 32% increase from our PUDs as of December 31, 2011. All of our PUDs at year-end 2012 were associated with the Marcellus Shale. The December 31, 2012 PUDs consisted of 26 gross (12.8 net) Marcellus horizontal wells in Appalachia. The increase in PUD well locations in 2012 is due to the successful Marcellus Shale drilling program in 2012, partially offset by the 18 gross (7.0 net) PUD reserves that we converted to proved developed reserves in 2012. The following table summarizes our PUD activity during the year ended December 31, 2012:

	Natural Gas (MMcf)	NGLs (MBbls)	Condensate and Oil (MBbls)	MMcfe
PUDs as of December 31, 2011	26,592	1,418	1,017	41,198
Extensions and discoveries	34,089	1,644	1,413	52,426
PUDs converted to proved developed	(24,963)	(1,330)	(947)	(38,624)
Revisions of previous estimates	(309)	(25)	(48)	(744)
PUDs as of December 31, 2012	35,409	1,707	1,435	54,256

Estimated future development costs relating to the development of 2012 year-end PUDs is $70.3 million of which 2013 and 2014 expenditures are $25.7 million and $31.6 million, respectively. Under current SEC requirements, PUD reserves may only be booked if they related 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, 2012 are scheduled to be drilled by 2015, which is within five years from the date initially recorded as PUD reserves. We may be required to remove our PUDs if we do not drill those reserves within the required five year time frame.

Item 3. Legal Proceedings

Information about our legal proceedings is set forth in Note 15, “Commitments and Contingencies – Litigation” to our consolidated financial statements, which begin on page F-1 of this Form 10-K.

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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 for the 2012 and 2011 annual periods.

	NYSE MKT LLC	
	High	Low
2012:		
Fourth quarter	$1.73	$0.72
Third quarter	$2.05	$1.55
Second quarter	$2.95	$1.55
First quarter	$3.31	$2.67
2011:		
Fourth quarter	$3.96	$2.63
Third quarter	$4.86	$3.00
Second quarter	$4.85	$3.20
First quarter	$4.95	$4.02

The last reported sale price of our common shares on the NYSE MKT on March 7, 2013 was $1.24.
Shareholders
As of March 7, 2013, there were 358 shareholders of record who owned our common shares.
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, our Revolving Credit Facility prohibits us from paying cash dividends on our common shares as long as any debt remains outstanding under the facility. Pursuant to the provisions of the Business Corporations Act (Alberta), we are prohibited from declaring or paying a dividend if there are reasonable grounds for believing that (1) we are, or would after the payment be, unable to pay our liabilities as they become due or (2) the realizable value of our assets would thereby be less than the aggregate of our liabilities and stated capital of all classes.
Gastar USA will pay cumulative dividends on the Series A Preferred Stock at a fixed rate of 8.625% per annum of the $25.00 per share liquidation preference, or $2.15625 per share outstanding each year, of no more than $10.0 million in the aggregate in each calendar year and as long as payment of such dividends does not exceed 5% of the current availability under the then existing borrowing base under the Revolving Credit Facility.
Recent Sales of Unregistered Securities; Use of Proceeds from Unregistered Securities
We did not have any sales of unregistered securities during the year ended December 31, 2012.

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

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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.

Financial information as of and for the years ended December 31, 2012, 2009 and 2008 includes impairment of natural gas and oil properties of $150.8 million, $68.7 million and $14.2 million, respectively. Financial information as of and for the years ended December 31, 2012 and 2010 includes litigation settlement expense of $1.3 million and $21.7 million, respectively. Financial information as of and for the year ended December 31, 2009 reflects gains on sale of assets of $211.2 million. Additionally, financial information as of and for the year ended December 31, 2009 includes expenses related to the early extinguishment of debt of $15.9 million.

	As of and for the Years Ended December 31,				
	2012	2011	2010	2009	2008
		(in thousands, except per share data)			
Consolidated Statements of Operations:					
Revenues	$49,940	$40,235	$42,768	$32,869	$63,219
Loss from operations	$(153,528)	$(631)	$(15,019)	$(76,930)	$(976)
Net income (loss) attributable to Gastar Exploration Ltd.	$(160,868)	$(1,764)	$(12,460)	$48,846	$(5,361)
Net income (loss) attributable to Gastar Exploration Ltd. per share:					
Basic	$(2.53)	$(0.03)	$(0.25)	$1.06	$(0.13)
Diluted	$(2.53)	$(0.03)	$(0.25)	$1.06	$(0.13)
Weighted average common shares outstanding					
Basic	63,538	63,004	49,814	46,103	41,420
Diluted	63,538	63,004	49,814	46,210	41,420
Consolidated Balance Sheets:					
Property, plant and equipment, net	$256,251	$285,740	$215,115	$162,661	$252,527
Total assets	$290,068	$334,503	$247,352	$296,238	$288,437
Long-term liabilities	$106,020	$39,438	$14,295	$18,371	$5,095
Total shareholders' equity	$49,895	$207,803	$207,391	$164,896	$101,582

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

Overview

We are an independent energy company engaged in the exploration, development and production of natural gas, condensate, oil and NGLs in the U.S. Our principal business activities include the identification, acquisition, and subsequent exploration and development of natural gas and oil properties with an emphasis on unconventional reserves, such as shale resource plays and application of horizontal drilling technology to conventional reservoirs. We are currently pursuing the development of liquids-rich natural gas in the Marcellus Shale in West Virginia and, to a lesser extent, central and southwestern Pennsylvania and oil in the Mid-Continent area of the U.S. We also hold prospective acreage in the deep Bossier play in the Hilltop area of East Texas.

Parent is a Canadian corporation, incorporated in Alberta in 1987 and subsisting under the Business Corporations Act (Alberta), with its common shares listed on the NYSE MKT under the symbol "GST." Parent is a holding company. Substantially all of the Company's operations are conducted through, and substantially all of its assets are held by, Parent's primary operating subsidiary, Gastar USA, and its subsidiaries. Gastar USA's Series A Preferred Stock is listed on the NYSE MKT under the symbol "GST.PRA."

Our current operational activities are conducted primarily in the U.S. As of December 31, 2012, our major assets consist of approximately 107,600 gross (75,200 net) acres in the Marcellus Shale in West Virginia and southwestern Pennsylvania, approximately 41,900 gross (17,300 net) acres in the Mid-Continent area of the U.S., and approximately 33,000 gross (17,000 net) acres in the Bossier play in the Hilltop area of East Texas. During the past three years, we spent approximately $315.8 million in acreage, seismic, capitalized interest, drilling advances, reserve acquisition and exploratory and development drilling on this acreage. We have not attained positive net income from operations in the past three years. There can be no assurance

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that operating income and net earnings will be achieved in future periods. As we continue the exploitation and development drilling in the Marcellus Shale and 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 natural gas, condensate, oil and NGLs;
- The level of total sales volumes of natural gas, condensate, oil 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 natural gas, condensate, oil and NGLs prices that are influenced by many factors beyond our control. We focus our efforts on increasing natural gas, condensate and oil 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 natural gas, condensate, oil and NGLs prices in future periods.

Like other natural gas and oil exploration and production companies, we face natural production declines. As initial reservoir pressures are depleted, natural gas, condensate, oil and NGLs production from a given well will decrease. Thus, a natural gas and oil exploration and production company depletes part of its asset base with each unit of natural gas, condensate, oil 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 and acquisitions, 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.

2012 Highlights

Marcellus Shale Drilling Program. During 2012, we focused our efforts and spent the majority of our capital budget on our liquids-rich acreage in the Marcellus Shale. During the year ended December 31, 2012, we drilled and completed 29 gross (13.4 net) operated wells in Marshall County, West Virginia, under the Atinum Joint Venture. At December 31, 2012, we had 38 gross (17.4 net) operated wells on production in Marshall County, West Virginia. At December 31, 2012, our proved reserves attributable to our Marcellus Shale acreage were approximately 153.2 Bcfe, a significant increase from-year end 2011 reserves of 84.0 Bcfe. Marcellus Shale proved reserves represented approximately 85% of our total proved reserves at December 31, 2012. Condensate and oil and NGLs reserves comprised approximately 32% of the total Marcellus Shale proved reserves at year end 2012.

Mid-Continent Horizontal Oil Play. At December 31, 2012, we held leases covering approximately 41,900 gross (17,300 net) acres in the non-operated Mid-Continent horizontal oil play and had completed our first non-operated well in the play. The initial well was completed at an initial 30-day after-processing average gross rate of 105 barrels of oil equivalent per day, comprised of 84 barrels of oil per day, 12 barrels of NGLs per day, 57 Mcf of natural gas per day and 428 barrels of completion fluids per day. The well continues to unload completion fluids with approximately 31% of frac fluid flowed back as of March 7, 2013. Based on the 30 days ended February 20, 2013, the well produced at an after-processing average gross rate of 105 barrels of oil equivalent per day, comprised of 69 barrels of oil per day, 20 barrels of NGLs per day, 94 Mcf of natural gas per day and 247 barrels of completion fluids per day. If successful, the Mid-Continent play should result in a low-cost, repeatable horizontal oil development play.

Financial Highlights

Our consolidated financial statements reflect total revenue of $49.9 million on total volumes of 13.2 Bcfe for the year ended December 31, 2012. Our operating loss for the year ended December 31, 2012 was $153.5 million and included depreciation, depletion and amortization expense of $25.4 million and impairment of natural gas and oil properties of $150.8 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 begin on page F-1.

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For additional information about production volumes, prices of natural gas and oil 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,		
	2012	2011	2010
	(In thousands, except per unit amounts)		
Revenues:			
Natural gas	$33,829	$33,391	$30,812
Condensate and oil	12,377	3,416	742
NGLs	9,300	1,092	—
Unrealized hedge gain (loss)	(5,566)	2,336	11,214
Total revenues	$49,940	$40,235	$42,768
Production:			
Natural gas (MMcf)	10,564	7,318	