ANTERO RESOURCES Corp
Form 10-K
February 25, 2015

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10 K

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

Commission File No. 001 36120

ANTERO RESOURCES CORPORATION

(Exact name of registrant as specified in its charter)

Delaware	80 0162034
(State or other jurisdiction of incorporation or organization)	(IRS Employer Identification No.)
1615 Wynkoop Street	
Denver Colorado	80202
(Address of principal executive offices)	(Zip Code)

(303) 357 7310

(Registrant's telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Exchange on which Registered
Common Stock, Par Value $0.01 Per Share	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act: None.

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

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

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

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

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

The aggregate market value of the voting common stock held by non affiliates of the registrant as of June 30, 2014, the last business day of the registrant's most recently completed second fiscal quarter, was approximately $3.6 billion.

The registrant had 262,073,239 shares of common stock outstanding as of February 19, 2015.

Documents incorporated by reference: Portions of the registrant's proxy statement for its annual meeting of stockholders to be filed pursuant to Regulation 14A within 120 days after the registrant's fiscal year end are incorporated by reference into Part III of this Annual Report on Form 10 K.

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CAUTIONARY STATEMENT REGARDING FORWARD LOOKING STATEMENTS

The information in this report includes "forward looking statements" within the meaning of 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 in this Annual Report on Form 10 K, regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management are forward looking statements. When used, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "project" and similar expressions are intended to identify forward looking stateme although not all forward looking statements contain such identifying words. These forward looking statements are based on our current expectations and assumptions about future events and are based on currently available information as to the outcome and timing of future events. When considering forward looking statements, you should keep in mind the risk factors and other cautionary statements described under the heading "Item 1A. Risk Factors" in this Annual Report on Form 10 K. These forward looking statements are based on management's current belief, based on currently available information, as to the outcome and timing of future events.

Forward looking statements may include statements about our:

- business strategy;
- reserves;
- financial strategy, liquidity and capital required for our development program;
- realized natural gas, natural gas liquids ("NGLs"), and oil prices;
- timing and amount of future production of natural gas, NGLs, and oil;
- hedging strategy and results;
- ability to utilize or monetize our firm transportation commitments;
- future drilling plans;
- competition and government regulations;
- pending legal or environmental matters;
- marketing of natural gas, NGLs, and oil;
- leasehold or business acquisitions;
- costs of developing our properties;
- the operations of Antero Midstream Partners LP;
- general economic conditions;
- credit markets;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations and intentions contained in this report that are not historical.

We caution you that these forward looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond our control, incident to the exploration for and development, production, gathering and sale of natural gas, NGLs, and oil. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, marketing and transportation risks, regulatory changes, the uncertainty inherent in estimating natural gas, NGLs, and oil reserves and in projecting

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future rates of production, cash flow and access to capital, the timing of development expenditures, and the other risks described under the heading “Item 1A. Risk Factors” in this Annual Report on Form 10 K.

Reserve engineering is a process of estimating underground accumulations of natural gas, NGLs, and oil that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by reservoir engineers. In addition, the results of drilling, testing and production activities, or changes in commodity prices, may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ significantly from the quantities of natural gas, NGLs, and oil that are ultimately recovered.

Should one or more of the risks or uncertainties described in this report occur, or should underlying assumptions prove incorrect, our actual results and plans could differ materially from those expressed in any forward looking statements.

All forward looking statements, expressed or implied, included in this report are expressly qualified in their entirety by this cautionary statement. This cautionary statement should also be considered in connection with any subsequent written or oral forward looking statements that we or persons acting on our behalf may issue.

Except as otherwise required by applicable law, we disclaim any duty to update any forward looking statements, all of which are expressly qualified by the statements in this section, to reflect events or circumstances after the date of this Annual Report on Form 10 K.

GLOSSARY OF OIL AND NATURAL GAS TERMS

The following are abbreviations and definitions of certain terms used in this document, which are commonly used in the oil and gas industry:

“Basin.” A large natural depression on the earth’s surface in which sediments, generally brought by water, accumulate.

“Bbl.” One stock tank barrel, of 42 U.S. gallons liquid volume, used herein in reference to crude oil, condensate, NGLs, or water.

“Bcf.” One billion cubic feet of natural gas.

“Bcfe.” One billion cubic feet of natural gas equivalent with one barrel of oil, condensate or NGLs converted to six thousand cubic feet of natural gas.

“Btu.” British thermal unit.

“Completion.” The process of treating a drilled well followed by the installation of permanent equipment for the production of natural gas or oil, or in the case of a dry hole, the reporting of abandonment to the appropriate agency.

“DD&A.” Depreciation, depletion, and amortization.

“Delineation.” The process of placing a number of wells in various parts of a reservoir to determine its boundaries and production characteristics.

“Developed acreage.” The number of acres that are allocated or assignable to productive wells or wells capable of production.

“Development well.” A well drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

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

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

“Field.” An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

“Formation.” A layer of rock which has distinct characteristics that differs from nearby rock.

“Gross acres or gross wells.” The total acres or wells, as the case may be, in which a working interest is owned.

“Horizontal drilling.” A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a right angle within a specified interval.

“MBbl.” One thousand barrels of crude oil, condensate or NGLs.

“Mcf.” One thousand cubic feet of natural gas.

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"MMBbl." One million barrels of crude oil, condensate or NGLs.

"MMBtu." One million British thermal units.

"MMcf." One million cubic feet of natural gas.

"MMcf/d" MMcf per day.

"MMcfe." One million cubic feet of natural gas equivalent with one barrel of oil, condensate or NGLs converted to six thousand cubic feet of natural gas.

"MMcfe/d." MMcfe per day.

"NGLs." Natural gas liquids. Hydrocarbons found in natural gas which may be extracted as liquefied petroleum gas and natural gasoline.

"NYMEX." The New York Mercantile Exchange.

"Net acres." The percentage of total acres an owner has out of a particular number of acres, or a specified tract. An owner who has 50% working interest in 100 acres owns 50 net acres.

"Net well." The percentage ownership interest in a well that an owner has based on the working interest. An owner who has a 50% working interest has a 0.50 net well.

"Potential well locations." Total gross resource play locations that we may be able to drill on our existing acreage. Actual drilling activities may change depending on the availability of capital, regulatory approvals, seasonal restrictions, natural gas and oil prices, costs, drilling results and other factors.

"Productive well." A well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of the production exceed production expenses and taxes.

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

"Proved developed reserves." Reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

"Proved reserves." The estimated quantities of oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be commercially recoverable in future years from known reservoirs under existing economic and operating conditions.

"Proved undeveloped reserves ("PUD")." Proved reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion.

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"PV 10." When used with respect to natural gas and oil reserves, PV 10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production, future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non property related expenses, discounted to a present value using an annual discount rate of 10% in accordance with the guidelines of the SEC. PV 10 is not a financial measure calculated in accordance with generally accepted accounting principles ("GAAP") and generally differs from Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. Neither PV 10 nor Standardized Measure represents an estimate of the fair market value of our natural gas and oil properties. We and others in the industry use PV 10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities.

"Recompletion." The process of re entering an existing wellbore that is either producing or not producing and completing new reservoirs in an attempt to establish or increase existing production.

"Reservoir." A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is separate from other reservoirs.

"Spacing." The distance between wells producing from the same reservoir. Spacing is often expressed in terms of acres, e.g., 40 acre spacing, or distance between two horizontal well legs, and is often established by regulatory agencies.

"Standardized measure." Discounted future net cash flows estimated by applying year end prices to the estimated future production of year end proved reserves. Future cash inflows are reduced by estimated future production and development costs based on period end costs to determine pre tax cash inflows. Future income taxes, if applicable, are computed by applying the statutory tax rate to the excess of pre tax cash inflows over our tax basis in the natural gas and oil properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate.

"Undeveloped acreage." Lease acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of natural gas, NGLs, and oil regardless of whether such acreage contains proved reserves.

"Unit." The joining of all or substantially all interests in a reservoir or field, rather than a single tract, to provide for development and operation without regard to separate property interests. Also, the area covered by a unitization agreement.

"Working interest." The right granted to the lessee of a property to explore for and to produce and own natural gas or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

"WTI." West Texas Intermediate light sweet crude oil.

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PART I

Items 1 and 2. Business and Properties

Our Company

Antero Resources Corporation is an independent oil and natural gas company engaged in the exploration, development and acquisition of natural gas, NGLs, and oil properties located in the Appalachian Basin. We focus on unconventional reservoirs, which can generally be characterized as fractured shale formations. As of December 31, 2014, we held approximately 543,000 net acres of oil and gas properties located in the Appalachian Basin in West Virginia, Ohio and Pennsylvania. Our corporate headquarters are in Denver, Colorado.

The following table provides a summary of selected data for our Appalachian Basin natural gas, NGLs, and oil assets as of the date and for the period indicated.

	At December 31, 2014					Three months ended December 31, 2014
	Proved Reserves (Bcfe)(1)	PV-10 (in millions)(2)	Net proved developed wells(3)	Total net acres(4)	Gross potential drilling locations(5)	Average net daily production (MMcfe/d)
Appalachian Basin:						
Marcellus Shale	11,918	$ 9,920	367	395,000	3,191	1,074
Upper Devonian	8	$ 8	2	—	1,116	—
Deep Utica Shale rights	—	—	—	—	—	—
Utica Shale	757	$ 1,392	53	148,000	1,024	191
Total	12,683	$ 11,320	422	543,000	5,331	1,265

(1) Estimated proved reserve volumes and values were calculated assuming ethane rejection and using the unweighted twelve month average of the first day of the month reference prices for the period ended December 31, 2014, which were $4.07 per MMBtu for natural gas, $45.89 per Bbl for NGLs and $81.48 per Bbl for oil for the Appalachian Basin based on a $94.42 WTI reference price.

(2) PV 10 is a non GAAP financial measure. For a reconciliation of PV 10 to standardized measure, please see "—Our Properties and Operations—Estimated Proved Reserves."

(3) Does not include certain shallow vertical wells that were acquired in conjunction with leasehold acreage acquisitions.

(4) Net acres allocable to the Upper Devonian and the deep Utica Shale rights are included in the net acres allocated to the Marcellus Shale, because these multi horizon shale formations are generally attributable to the same leases.

(5) See "Item 1A. Risk Factors" for risks and uncertainties related to developing our potential well locations.

Our management team has worked together for many years and has a successful track record of reserve and production growth as well as significant expertise in unconventional resource plays. Our strategy is to leverage our team's experience delineating and developing natural gas and NGLs resource plays to profitably grow our reserves and production, primarily on our existing multi year project inventory.

We have assembled a portfolio of long lived properties that are characterized by what we believe to be low geologic risk and repeatability. Our drilling opportunities are focused in the Marcellus Shale and Utica Shale of the Appalachian Basin. From 2008 through December 31, 2014, our drilling operations in the Appalachian Basin have had a 100% success rate. We have approximately 5,331 potential horizontal well locations on our existing leasehold acreage, both proven and unproven.

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We have secured sufficient long term firm takeaway capacity on major pipelines that are in existence or currently under construction in each of our core operating areas to accommodate our current development plans.

We operate in the following industry segments: (i) the exploration, development and production of natural gas, NGLs, and oil, (ii) gathering and compression, (iii) fresh water distribution, and (iv) marketing of excess firm transportation capacity. All of our operations are conducted in the United States. Financial information for our industry segment operations is located under "Note 13: Segment Information".

2014 Developments and Highlights

Energy Industry Environment

Recently, global energy commodity prices have declined precipitously as a result of several factors including increased worldwide supplies, a stronger U.S. dollar, relatively mild weather in the U.S., and strong competition among oil producing countries for market share. Specifically, prices for WTI have declined from approximately $106.00 per Bbl in June 2014 to less than $50.00 per Bbl in January 2015. Henry Hub natural gas has traded around $3.00 per MMBtu in January 2015 compared to prices a year ago in January 2014 of around $4.40 per MMBtu. In response to these market conditions and concerns about access to capital markets, U.S. exploration and development companies have significantly reduced capital spending plans. Our capital budget for 2015 is $1.8 billion (not including the capital budget of Antero Midstream Partners LP), a 41% reduction from our final 2014 capital budget. We plan to operate an average of 14 drilling rigs in 2015 down from 21 at December 31, 2014 and to complete 130 horizontal Marcellus and Utica wells in 2015, down from 177 in 2014. We believe that our 2015 capital budget will be fully funded through operating cash flow and available borrowing capacity under our revolving credit facility. We will continue to monitor commodity prices and may revise the capital budget if conditions warrant.

Initial Public Offering of Subsidiary

On November 10, 2014, our subsidiary, Antero Midstream Partners LP ("Antero Midstream"), completed its initial public offering ("IPO"). We contributed midstream gathering and compression assets to Antero Midstream as well as rights to develop additional midstream infrastructure to service our growing production. Additionally, Antero Midstream has an option to purchase our fresh water distribution systems at fair market value. A total of 46 million common units representing limited partner interests were sold in the IPO at a price to the public of $25.00 per common unit. After subtracting underwriting discounts and offering costs, net proceeds received by Antero Midstream were approximately $1.1 billion. Antero Midstream used approximately $843 million of the net proceeds to repay indebtedness assumed from us and to reimburse us for certain capital expenditures incurred. Antero Midstream retained $250 million of the net proceeds for general partnership purposes. After completion of the IPO, we own approximately 69.7% of the outstanding limited partner interests in Antero Midstream and the public owns the remaining 30.3% of the limited partner interests in Antero Midstream.

Reserves, Production, and Financial Results

As of December 31, 2014, our estimated proved reserves were 12.7 Tcfe, consisting of 10.5 Tcf of natural gas, 330 MMBbl of NGLs and 28 MMBbl of oil. As of December 31, 2014, 83% of our estimated proved reserves by volume were natural gas, 16% were NGLs, and 1% was oil. Proved developed reserves were 3.8 Tcfe, or 30% of total proved reserves.

For the year ended December 31, 2014, our production totaled 368 Bcfe, or 1,007 MMcfe per day. The 2014 production levels represent a 93% increase over 2013 levels. The average price received for 2014 production before the effects of realized hedge gains was $4.73 per Mcfe compared to $4.31 in 2013. The 10% increase was primarily attributable to the increased proportion of NGLs and oil production to total production in 2014 compared to the prior year. Average prices after the effects of cash settled commodity hedges were $5.10 per Mcfe for 2014 compared to $5.17 per Mcfe for 2013.

For the year ended December 31, 2014, we generated cash flow from operations of $998 million, net income of $674 million, and Adjusted EBITDAX of $1.2 billion. Net income in 2014 included (i) unrealized hedge gains of $732 million (ii) a noncash charge of $112 million for equity-based compensation, (iii) a noncash tax expense of $446 million, (iv) a charge of $20 million for redemption premiums and the write off of unamortized deferred financing charges and premium associated with the retirement of $260 million of our 7.25% senior notes due 2019, and (v) income from discontinued operations of $2 million. See “Item 6. Selected Financial Data” for a definition of Adjusted EBITDAX (a non GAAP measure) and a reconciliation of Adjusted EBITDAX to net income (loss).

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2014 Capital Spending and 2015 Capital Budget

For the year ended December 31, 2014, our total capital expenditures were approximately $4.1 billion, including drilling and completion costs of $2.5 billion, gathering and compression project costs of $558 million, fresh water distribution project costs of $197 million, $841 million of leasehold costs (including $415 million of acquisitions and $426 million on land), and other capital expenditures of $13 million. Our capital budget for 2015 is $1.8 billion and includes: $1.6 billion for drilling and completion; $50 million for fresh water distribution infrastructure; and $150 million for core leasehold acreage acquisitions. We do not budget for producing property acquisitions. All of the $1.6 billion allocated for drilling and completion is allocated to our operated drilling in liquids-rich gas areas. Approximately 60% of the drilling and completion budget is allocated to the Marcellus Shale, and the remaining 40% is allocated to the Utica Shale. During 2015, we plan to operate an average of nine drilling rigs in the Marcellus Shale and five drilling rigs in the Utica Shale. Additionally, the capital budget for Antero Midstream for 2015 is a range of $425 million to $450 million. We periodically review our capital expenditures and adjust our budget and its allocation based on liquidity, drilling results, leasehold acquisition opportunities, commodity prices, and liquidity.

Hedge Position

At December 31, 2014, we had entered into hedging contracts for January 1, 2015 through December 31, 2020 for 1.758 Tcf of our projected natural gas production at a weighted average index price of $4.41 per MMBtu, 1.1 million Bbls of oil at a weighted average price of $64.58 per Bbl, and 352.6 million gallons of propane at a weighted average price of $0.61 per gallon. These hedging contracts include contracts for the year ending December 31, 2015 of approximately 423.4 Bcf of natural gas at a weighted average index price of $4.34 per MMBtu, 1.1 million Bbls of oil at a weighted average price of $64.58 per Bbl, and 352.6 million gallons of propane at a weighted average price of $0.61 per gallon. We believe this hedge position provides protection to cash flows supporting our future operations and capital spending plans for 2015 through 2020.

Credit Facilities

The current borrowing base under our revolving credit facility is $4.0 billion and lender commitments are $4.0 billion. The borrowing base under our revolving credit facility is redetermined semi annually and is based on the estimated future cash flows from our proved reserves and our hedge positions. The next redetermination is scheduled to occur in October 2015. Our revolving credit facility provides for a maximum availability of $4.0 billion. At December 31, 2014, we had $1.73 billion of borrowings and $387 million of letters of credit outstanding under the revolving credit facility. Our revolving credit facility matures in May 2019. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Debt Agreements and Contractual Obligations—Senior Secured Revolving Credit Facility” for a description of our revolving credit facility.

On November 10, 2014, in connection with the closing of the Antero Midstream IPO, Antero Midstream entered into a revolving credit facility agreement that provides for lender commitments of $1.0 billion. The facility will mature on November 10, 2019. See “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations—Debt Agreements and Contractual Obligations—Midstream Credit Facility” for a description of this revolving credit facility.

Issuance of $1.1 Billion 5.125% Senior Notes Due 2022

On May 6, 2014, we issued $600 million of 5.125% senior notes due 2022 (the “2022 notes”) at par. Net proceeds from the offering of $592 million were used to retire the remaining $260 million principal amount of our 7.25% notes due 2019 and for general corporate purposes, including paying down amounts outstanding under our revolving credit facility and funding our drilling and development program. We incurred a loss on early extinguishment of debt of $20 million on the retirement of the 7.25% notes. On September 18, 2014, we issued an additional $500 million of the 2022 notes at 100.5% of par. The net proceeds from the additional issuance of 2022 notes were used to pay down amounts outstanding under our revolving credit facility.

As of December 31, 2014, we had three series of senior notes outstanding totaling $2.6 billion in aggregate principal amount. The notes have maturity dates ranging from December 1, 2020 to December 1, 2022, and interest rates ranging from 5.125% to 6.00%.

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Our Properties and Operations

Estimated Proved Reserves

The information with respect to our estimated proved reserves presented below has been prepared in accordance with the rules and regulations of the SEC.

Reserves Presentation

The following table summarizes our estimated proved reserves and related standardized measure and PV 10 at December 31, 2012, 2013, and 2014. Our estimated proved reserves are based on evaluations prepared by our internal reserve engineers, which have been audited by our independent engineers, DeGolyer and MacNaughton ("D&M"). We refer to D&M as our independent engineers. A copy of the summary report of D&M with respect to our reserves at December 31, 2014 is filed as Exhibit 99.1 to this Annual Report on Form 10 K. The information in the following table does not give any effect to or reflect our commodity hedges. Reserves at December 31, 2012 were prepared assuming ethane recovery from our production process, while reserves at December 31, 2013 and 2014 were prepared assuming ethane rejection. When ethane is rejected at the processing plant, it is left in the gas stream and sold with the methane gas.

	At December 31,		
	2012	2013	2014
Estimated proved reserves:			
Proved developed reserves:			
Natural gas (Bcf)	828	1,818	3,285
NGLs (MMBbl)	36	33	80
Oil (MMBbl)	1	2	6
Total equivalent proved developed reserves (Bcfe)	1,047	2,022	3,803
Proved undevoped reserves:			
Natural gas (Bcf)	2,866	4,936	7,250
NGLs (MMBbl)	167	105	250
Oil (MMBbl)	2	8	22
Total equivalent proved undeveloped reserves (Bcfe)	3,882	5,610	8,880
Total estimated proved reserves (Bcfe)	4,929	7,632	12,683
Proved developed producing (Bcfe)	935	1,771	3,508
Proved developed non-producing (Bcfe)	112	251	295
Percent developed	21 %	27 %	30 %
PV-10 (in millions)(1)	$ 1,923	$ 5,998	$ 11,320
Standardized measure (in millions)(1)	$ 1,601	$ 4,510	$ 7,635

(1) Pre-tax PV 10 was prepared using average yearly prices computed using SEC rules, discounted at 10% per annum, without giving effect to taxes. Pre-tax PV 10 is a non GAAP financial measure. We believe that the presentation of pre-tax PV 10 is relevant and useful to our investors as supplemental disclosure to the standardized measure of future net cash flows, or after tax amount, because it presents the discounted future net cash flows attributable to our proved reserves prior to taking into account future corporate income taxes and our current tax structure. While the standardized measure is dependent on the unique tax situation of each company, pre-tax PV 10 is based on a pricing methodology and discount factors that are consistent for all companies. Because of this, pre-tax PV 10 can

be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows from proved reserves on a more comparable basis. The difference between the standardized measure and the pre-tax PV 10 amount is the discounted amount of estimated future income taxes. For more information about the calculation of standardized measure, see footnote 18 to our consolidated financial statements included in Item 8 of this Annual Report on Form 10 K.

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The following sets forth the estimated future net cash flows from our proved reserves (without giving effect to our commodity hedges), the present value of those net cash flows before income tax (PV 10), the present value of those net cash flows after income tax (standardized measure) and the prices used in projecting future net cash flows at December 31, 2012, 2013, and 2014:

	At December 31,		
(In millions, except per Mcf data)	2012(1)	2013(2)	2014(3)
Future net cash flows	$ 7,221	$ 18,797	$ 33,698
Present value of future net cash flows:			
Before income tax (PV-10)	$ 1,923	$ 5,998	$ 11,320
Income taxes	$ (322)	$ (1,488)	$ (3,685)
After income tax (Standardization measure)	$ 1,601	$ 4,510	$ 7,635

(1) 12 month average prices used at December 31, 2012 were $2.78 per MMBtu for natural gas, $19.61 per Bbl for NGLs, and $85.05 per Bbl for oil for the Appalachian Basin based on a $95.05 WTI reference price.
(2) 12 month average prices used at December 31, 2013 were $3.65 per MMBtu for natural gas, $47.13 per Bbl for NGLs, and $87.00 per Bbl for oil for the Appalachian Basin based on a $97.17 WTI reference price.
(3) 12 month average prices used at December 31, 2014 were $4.07 per MMBtu for natural gas, $45.89 per Bbl for NGLs, and $81.48 per Bbl for oil for the Appalachian Basin based on a $94.42 WTI reference price.

Future net cash flows represent projected revenues from the sale of proved reserves net of production and development costs (including operating expenses and production taxes). Prices for 2012, 2013, and 2014 were based on 12 month unweighted average of the first day of the month pricing, without escalation. Costs are based on costs in effect for the applicable year without escalation. There can be no assurance that the proved reserves will be produced as estimated or that the prices and costs will remain constant. There are numerous uncertainties inherent in estimating reserves and related information and different reservoir engineers often arrive at different estimates for the same properties.

Changes in Proved Reserves During 2014

The following table summarizes the changes in our estimated proved reserves during 2014 (in Bcfe):

Proved reserves, December 31, 2013	7,632
Extensions, discoveries, and other additions	6,444
Purchase of reserves	29
Performance revisions	361
Revisions due to 5-year development rule	(1,417)
Price revisions	2
Production	(368)
Proved reserves, December 31, 2014	12,683

Extensions, discoveries, and other additions during 2014 of 6,444 Bcfe were added through delineation and developmental drilling in the Marcellus and Utica Shales. Purchases of 29 Bcfe relate to five horizontal producing wells acquired as part of our leasehold acquisition efforts. Performance revisions of 361 Bcfe relate to improved well performance from shorter stage length completions. Downward revisions of 1,417 Bcfe were due to the reclassification of 191 dry gas locations to the probable category because they are no longer expected to be drilled within five years of initial booking. Upward price revisions of 2 Bcfe were due to increases in the reference price for natural gas, partially offset by decreases in the reference prices for NGLs and oil. Our estimated proved reserves as of December 31, 2014 totaled approximately 12.7 Tcfe and increased by 66% over the prior year.

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Proved Undeveloped Reserves

Proved undeveloped reserves are included in the previous table of total proved reserves. The following table summarizes the changes in our estimated proved undeveloped reserves during 2014 (in Bcfe):

Proved undeveloped reserves, December 31, 2013	5,610
Extension, discoveries, and other additions	5,570
Reclassifications to proved developed reserves	(1,112)
Performance revisions	228
Revisions due to 5-year development rule	(1,417)
Price revisions	1
Proved undeveloped reserves, December 31, 2014	8,880

Extensions, discoveries, and other additions during 2014 of 5,570 Bcfe of proved undeveloped reserves were added through delineation and developmental drilling in the Marcellus and Utica Shales. Development drilling resulted in the reclassification of 1,112 Bcfe to proved developed reserves. Performance revisions of 228 Bcfe relate to improved well performance from shorter stage length completions. Downward revisions of 1,417 Bcfe due were due to the reclassification of 191 dry gas wells to the probable category because they are no longer expected to be drilled within five years of initial booking, as our drilling plans are more focused on our liquids-rich acreage. Upward price revisions of 1 Bcfe were due to increases in the reference price for natural gas, partially offset by decreases in the reference prices for NGLs and oil. Proved undeveloped reserves include reserves that are expected to be drilled and developed within five years; wells that are not drilled within five years from booking are reclassified from proved reserves to probable reserves.

During the year ended December 31, 2014, we converted approximately 1,112 Bcfe of proved undeveloped reserves to proved developed reserves at a total capital cost of approximately $991 million. Estimated future development costs relating to the development of our proved undeveloped reserves at December 31, 2014 are approximately $8.2 billion over the next five years, which we expect to finance through cash flow from operations, borrowings under our revolving credit facility, and other sources of capital financing. Our drilling programs to date have focused on proving our undeveloped leasehold acreage through delineation drilling. While we will continue to drill leasehold delineation wells and build on our current leasehold position, we will also continue drilling our proved undeveloped reserves. All of our proved undeveloped reserves are expected to be developed over the next five years. See “Item 1A. Risk Factors—The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced.”

Preparation of Reserve Estimates

Our reserve estimates as of December 31, 2012, 2013, and 2014 included in this Annual Report on Form 10 K were prepared by our internal reserve engineers in accordance with petroleum engineering and evaluation standards published by the Society of Petroleum Evaluation Engineers and definitions and guidelines established by the SEC. Our internally prepared reserve estimates were audited by our independent reserve engineers. Our independent reserve engineers were selected for their historical experience and geographic expertise in engineering unconventional resources. The technical persons responsible for overseeing the audit of our reserve estimates presented herein 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.

Our internal staff of petroleum engineers and geoscience professionals work closely with our independent reserve engineers to ensure the integrity, accuracy and timeliness of data furnished to our independent reserve engineers in their reserve auditing process. Periodically, our technical team meets with the independent reserve engineers to review properties and discuss methods and assumptions used by us to prepare reserve estimates. Our internally prepared reserve estimates and related reports are reviewed and approved by our Vice President of Reserves, Planning & Midstream, Ward D. McNeilly, and our Vice President of Production, Kevin J. Kilstrom. Mr. McNeilly has been with the Company since October 2010. Mr. McNeilly has 35 years of experience in oil and gas operations, reservoir management, and strategic planning. From 2007 to October 2010 Mr. McNeilly was the Operations Manager for BHP Billiton's Gulf of Mexico operations. From 1996 through 2007, Mr. McNeilly served in various North Sea and Gulf of Mexico Deepwater operations and asset management positions with Amoco and then BP. From 1979 through 1996 Mr. McNeilly served in various domestic and international operations and reservoir and asset management positions with Amoco. Mr. McNeilly holds a B.S. in Geological Engineering from the Mackay School of Mines at the University of Nevada.

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Mr. Kilstrom has served as Vice President of Production since June 2007. Mr. Kilstrom was a Manager of Petroleum Engineering with AGL Energy of Sydney, Australia from 2006 to 2007. Prior to AGL, Mr. Kilstrom was with Marathon Oil as an Engineering Consultant and Asset Manager from 2003 to 2006 and as a Business Unit Manager for Marathon's Powder River coal bed methane assets from 2001 to 2003. Mr. Kilstrom also served as a member of the board of directors of three Marathon subsidiaries from October 2003 through May 2005. Mr. Kilstrom was an operations manager and reserve engineer at Pennaco Energy from 1999 to 2001. Mr. Kilstrom was at Amoco for more than 22 years prior to 1999 where he served in various operating roles with a focus on unconventional resources. Mr. Kilstrom holds a B.S. in Engineering from Iowa State University and an M.B.A. from DePaul University. Our senior management also reviews our reserve estimates and related reports with Mr. McNeilly and Mr. Kilstrom and other members of our technical staff. Additionally, our senior management reviews and approves any significant changes to our proved reserves on a quarterly basis.

Proved reserves are reserves 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 under existing economic conditions, operating methods and government regulations prior to the time at which contracts providing the right to operate expires, unless evidence indicates that renewal is reasonably certain. The term "reasonable certainty" implies a high degree of confidence that the quantities of oil or natural gas actually recovered will equal or exceed the estimate. To achieve reasonable certainty, we and the independent reserve engineers employed 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, well logs, geologic maps and available downhole and production data, micro seismic data and well test data. Probable reserves are reserves that are less certain to be recovered than proved reserves but which, together with proved reserves, are as likely as not to be recovered. Estimates of probable reserves which may potentially be recoverable through additional drilling or recovery techniques are by nature more uncertain than estimates of proved reserves and accordingly are subject to substantially greater risk of not actually being realized by us. Possible reserves are reserves that are less certain to be recovered than probable reserves. Estimates of possible reserves are also inherently imprecise. Estimates of probable and possible reserves are also continually subject to revisions based on production history, results of additional exploration and development, price changes and other factors.

Methodology Used to Apply Reserve Definitions

In the Marcellus Shale, our estimated reserves are based on information from our large, operated proved developed producing reserve base, as well as information from other operators in the area, which can be used to confirm or supplement our internal estimates. Typically, proved undeveloped properties are booked based on applying the estimated lateral length to the average Bcf per 1,000 feet from our proved developed producing wells.

We may attribute up to 11 proved undeveloped locations based on one proved developed producing well where analysis of geologic and engineering data can be estimated with reasonable certainty to be commercially recoverable. However, the ratio of proved undeveloped locations generated will be lower when multiple proved developed wells are drilled on a single pad. In addition, we have applied the concept of a Highly Developed Area, or HDA, to certain areas of our Marcellus Shale acreage whereby undeveloped properties are booked as proved reserves so long as well count is sufficient for statistical analysis and certain land, geologic, engineering and commercial criteria are met.

Although our operating history in the Utica Shale is more limited than our Marcellus Shale operations, we expect to be able to apply a similar methodology once the well count is sufficient for statistical analysis. The primary differences between the two areas are that (i) we have not established an HDA in the Utica Shale and (ii) each proved developed producing well in the Utica Shale only generates four direct offset well locations in the Utica Shale due to less relative maturity.

Identification of Potential Well Locations

Our identified potential well locations include locations to which proved, probable or possible reserves were attributable based on SEC pricing as of December 31, 2014. We prepare internal estimates of probable and possible reserves but have not included disclosure of such reserves in this report.

Production, Revenues, and Price History

Because natural gas, NGLs, and oil are commodities, the price that we receive for our production is largely a function of market supply and demand. While demand for natural gas in the United States has increased materially since 2000, natural gas and NGLs supplies have also increased significantly as a result of horizontal drilling and fracture stimulation technologies which have

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been used to find and recover large amounts of oil and gas from various shale formations throughout the United States. Demand is impacted by general economic conditions, weather and other seasonal conditions. Over or under supply of natural gas can result in substantial price volatility. Historically, commodity prices have been volatile, and we expect that volatility to continue in the future. The significant commodity price declines in late 2014 and early 2015 are the most recent example of such volatility. A substantial or extended decline in gas prices or poor drilling results could have a material adverse effect on our financial position, results of operations, cash flows, quantities of reserves that may be economically produced and our ability to access capital markets. See "Item 1A. Risk Factors—Natural gas, NGLs, and oil prices are volatile. A substantial or extended decline in commodity prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments."

The following table sets forth information regarding our production, revenues and realized prices, and production costs from continuing operations in the Appalachian Basin for the years ended December 31, 2012, 2013 and 2014. For additional information on price calculations, see information set forth in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations."

Continuing Operations Data—Appalachian Basin

	Year ended December 31,		
	2012	2013	2014
Production data:			
Natural gas (Bcf)	87	177	317
NGLs (MBbl)	71	2,123	7,102
Oil (MBbl)	19	226	1,311
Combined (Bcfe)	87	191	368
Daily combined production (MMcfe/d)	239	522	1,007
Average prices before effects of hedges:			
Natural gas (per Mcf)	$ 2.99	$ 3.90	$ 4.10
NGLs (per Bbl)	$ 52.07	$ 52.61	$ 46.23
Oil (per Bbl)	$ 80.34	$ 91.27	$ 81.65
Combined average sales prices before effects of cash settled derivatives (per Mcfe)(1)	$ 3.03	$ 4.31	$ 4.73
Combined average sales prices after effects of cash settled derivatives (per Mcfe)(1)	$ 5.08	$ 5.17	$ 5.10
Average Costs (per Mcfe):			
Lease operating	$ 0.07	$ 0.05	$ 0.08
Gathering, compression, processing, and transportation	$ 1.04	$ 1.15	$ 1.26
Production and ad valorem taxes	$ 0.23	$ 0.26	$ 0.24
Depletion, depreciation, amortization, and accretion	$ 1.17	$ 1.23	$ 1.30
General and administrative (before equity-based compensation)	$ 0.52	$ 0.32	$ 0.28

(1) Average prices shown reflect both of the before and after effects of our realized commodity hedging transactions. Our calculation of such effects includes realized gains or losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting because we do not designate them as hedges.

Discontinued Operations Data—Arkoma and Piceance Basins

The table above does not include 2012 production of 35 Bcfe or revenue of $125 million from discontinued operations from the Arkoma and Piceance Basin properties which were sold in 2012. See footnote 3 to the consolidated financial statements included in Item 8 of this Annual Report on Form 10 K for the results of discontinued operations.

Productive Wells

As of December 31, 2014, we had a total of 634 gross (593 net) producing wells, averaging a 93% working interest, in the Marcellus Shale. This well count includes 363 gross (353 net) horizontal wells, and 271 gross and (239 net) shallow vertical wells that were acquired in conjunction with leasehold acreage acquisitions. In the Utica Shale we had 53 gross (44 net) producing

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horizontal wells at December 31, 2014, averaging an 83% working interest. Our wells are gas wells, many of which also produce oil, condensate and NGLs. Additionally, at December 31, 2014 we had 102 gross horizontal wells (93 net) waiting on completion or pipeline connection.

Acreage

The following table sets forth certain information regarding the total developed and undeveloped acreage in which we owned an interest as of December 31, 2014. A majority of our developed acreage is subject to liens securing our revolving credit facility. Approximately 50% of our Marcellus acreage and 21% of our Utica acreage is held by production. Acreage related to royalty, overriding royalty and other similar interests is excluded from this table.

	Developed Acres		Undeveloped Acres		Total Acres	
Basin	Gross	Net	Gross	Net	Gross	Net
Marcellus	58,021	56,843	475,776	338,018	533,797	394,861
Utica Shale	12,491	9,439	161,985	138,903	174,476	148,342
Other	—	—	6,609	6,599	6,609	6,599
Total	70,512	66,282	644,370	483,520	714,882	549,802

The following table provides a summary of our current gross and net acreage by county in the Marcellus Shale and the Utica Shale.

	Marcellus	
County	Gross Acres	Net Acres
Doddridge, WV	190,683	135,480
Gilmer, WV	11,887	8,201
Harrison, WV	119,806	101,569
Lewis, WV	89	65
Marion, WV	3,800	3,655
Monongalia, WV	1,649	1,467
Pleasants, WV	4,844	2,604
Ritchie, WV	86,173	62,453
Tyler, WV	78,560	50,293
Wetzel, WV	7,233	3,709
Fayette, PA	7,364	5,423
Greene, PA	974	454
Washington, PA	13,601	12,552

Westmoreland, PA	7,134	6,936
Total Marcellus Shale	533,797	394,861

	Utica Gross Acres	Net Acres
Athens, OH	84	84
Belmont, OH	17,771	16,907
Guernsey, OH	10,342	8,435
Harrison, OH	577	577
Monroe, OH	58,207	53,438
Noble, OH	84,428	66,470
Washington, OH	3,067	2,431
Total Utica Shale	174,476	148,342
Total Marcellus and Utica Shale	708,273	543,203

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Undeveloped Acreage Expirations

The following table sets forth the number of total gross and net undeveloped acres as of December 31, 2014 that will expire over the next three years unless production is established within the spacing units covering the acreage prior to the expiration dates or unless such acreage is extended or renewed.

	Marcellus Gross Acres	Net Acres	Utica Gross Acres	Net Acres	Total Gross Acres	Net Acres
2015	31,095	21,383	5,226	3,384	36,321	24,767
2016	16,424	9,644	20,519	13,529	36,943	23,173
2017	65,811	41,427	58,048	50,742	123,859	92,169

Drilling Activity

The following table sets forth the results of our drilling activity for wells drilled and completed during the years ended December 31, 2012, 2013, and 2014. Gross wells reflect the sum of all wells in which we own an interest and includes historical drilling activity in the Appalachian, Arkoma, and Piceance Basins. Net wells reflect the sum of our working interests in gross wells.

	Year ended December 31,					
	2012		2013		2014	
	Gross	Net	Gross	Net	Gross	Net
Marcellus						
Development wells:						
Productive	48	45	49	48	77	76
Dry	—	—	—	—	—	—
Total development wells	48	45	49	48	77	76
Exploratory wells:						
Productive	15	15	63	62	43	42
Dry	—	—	—	—	—	—
Total exploratory wells	15	15	63	62	43	42
Utica						
Development wells:						
Productive	—	—	3	3	11	10
Dry	—	—	—	—	—	—
Total development wells	—	—	3	3	11	10
Exploratory wells:						
Productive	1	1	13	10	23	19
Dry	—	—	—	—	—	—
Total exploratory wells	1	1	13	10	23	19

Arkoma, Piceance, and Other						
Development wells:						
Productive	58	46	—	—	—	—
Dry	—	—	—	—	—	—
Total development wells	58	46	—	—	—	—
Exploratory wells:						
Productive	6	1	—	—	—	—
Dry	—	—	—	—	—	—
Total exploratory wells	6	1	—	—	—	—
Total						
Development wells:						
Productive	106	91	52	51	88	86
Dry	—	—	—	—	—	—
Total development wells	106	91	52	51	88	86
Exploratory wells:						
Productive	22	17	76	72	66	61
Dry	—	—	—	—	—	—
Total exploratory wells	22	17	76	72	66	61

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The figures in the table above do not include 102 gross wells (93 net) waiting on completion or pipeline connections at December 31, 2014.

Delivery Commitments

We have entered into various firm sales contracts to deliver and sell gas. We believe we will have sufficient production quantities to meet substantially all of such commitments, but may be required to purchase gas from third parties to satisfy shortfalls should they occur.

As of December 31, 2014, our firm sales commitments through 2019 included:

Year Ending December 31,	Volume of Natural Gas (Mmcf/d)	Firm Transport Capacity Utilized (MMcf/d)	Volume of Ethane (Bbl/day)
2015	570,000	290,000	—
2016	880,000	650,000	2,900
2017	800,000	670,000	11,500
2018	930,000	810,000	11,500
2019	880,000	780,000	11,500

As provided in the table above, we utilize a part of our firm transportation capacity to deliver gas under the majority of these firm sales contracts. We have firm transportation contracts that require us to deliver products to pipeline transporters or pay demand charges for shortfalls. The minimum demand fees are reflected in our table of contractual obligations. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Debt Agreements and Contractual Obligations." If our production quantities are insufficient to meet such commitments, we may purchase third party products or market our excess firm transportation capacity to third parties.

Midstream Operations

Our exploration and development activities are supported by the natural gas gathering and compression assets of our subsidiary, Antero Midstream, as well as by third party gathering, compression, processing, and transportation arrangements. Unlike many producing basins in the United States, certain portions of the Appalachian Basin do not have sufficient midstream infrastructure to support the existing and expected increasing levels of production. Our relationship with Antero Midstream allows us to obtain the necessary gathering and compression capacity for our production.

Prior to the Antero Midstream IPO, we committed to developing the necessary midstream infrastructure to support our drilling schedule and production growth. We accomplish this goal through a combination of internal asset developments and contractual relationships with third party midstream service providers. As part of our internal developments, we invested a significant amount of capital in building low and high pressure gathering lines, compressor stations and fresh water pipeline systems. In the past we have monetized certain midstream infrastructure assets for a significant return on investment and redeployed the proceeds into our ongoing operations. In 2014, we spent approximately $755 million on midstream gas, condensate and fresh water infrastructure.

As of December 31, 2014, our subsidiary, Antero Midstream, owned and operated 153 miles of gas gathering pipelines in the Marcellus Shale. We also have access to additional low pressure and high pressure pipelines owned and operated by Crestwood, Energy Transfer Partners L.P. and Summit Midstream. As of December 31, 2014, Antero Midstream owned and operated five compressor stations and utilized 16 additional third party compressor stations in the Marcellus Shale. The gathering, compression and dehydration services provided by third parties are contracted on a fixed fee basis.

As of December 31, 2014, Antero Midstream Partners LP owned and operated 96 miles of low pressure, high pressure and condensate pipelines in the Utica Shale, and we owned and operated 8 miles of high-pressure pipelines. As of December 31, 2014, we utilized 4 third party compressor stations in the Utica Shale.

Pursuant to our gathering and compression services agreement with Antero Midstream, we dedicated substantially all of our current and future acreage for gathering and compression services for 20 years. All of our existing acreage is dedicated to Antero Midstream for gathering and compression services except for acreage attributable to third party commitments in effect prior to the

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Antero Midstream IPO, which includes 131,000 Marcellus Shale net leasehold acres characterized by dry gas and liquids rich reserves that have been previously dedicated to third party gatherers. In addition to our existing acreage dedication, the agreement provides that any acreage we acquire in the future will be dedicated to Antero Midstream for gathering and compression services. Antero Midstream also provides condensate gathering services to us under the gathering and compression agreement.

Natural Gas Processing

Many of our wells in the Marcellus and Utica Shales allow us to produce liquids rich natural gas that contains a significant amount of NGLs. Natural gas containing significant amounts of NGLs must be processed, which involves the removal and separation of NGLs from the wellhead natural gas.

NGLs are valuable commodities once removed from the natural gas stream and fractionated into their key components. Fractionation refers to the process by which a NGLs stream is separated into individual NGLs products such as ethane, propane, normal butane, isobutane, and natural gasoline. Fractionation occurs by heating the mixed NGL stream to allow for the separation of the component parts based on the specific boiling points of each product. Each of the individual products have their own market price.

The combination of infrastructure constraints in the Appalachian region and low ethane prices has resulted in many producers “rejecting” rather than “recovering” ethane. Ethane rejection occurs when ethane is left in the wellhead gas stream when the gas is processed, rather than being separated out and sold as a liquid after fractionation. When ethane is left in the gas stream, the Btu content of the residue gas at the tailgate of the processing plant is higher. Producers will elect to “reject” ethane when the price received for the ethane in the gas stream is greater than the net price received for the ethane being sold as a liquid after fractionation. When ethane is recovered, the Btu content of the residue gas is lower, but a producer is then able to recover the value of the ethane sold as a separate product.

Given the existing commodity price environment and the current limited ethane market in the northeast, we are currently rejecting ethane when processing our liquids rich gas. However, we realize a significant pricing upgrade when selling the remaining NGL products stream at current prices. We will elect to recover ethane when ethane prices result in a value for the ethane that is greater than the Btu equivalent residue gas and incremental recovery costs.

Through third party contractual relationships, we have obtained committed cryogenic processing capacity for our Marcellus and Utica Shale production. For example, we have contracted with MarkWest to provide processing capacity as follows:

	Plant Processing Capacity (MMcf/d)	Contracted Firm Processing Capacity (MMcf/d)	Anticipated Date of Completion
Marcellus Shale:			
Sherwood I	200	200	In service
Sherwood II	200	200	In service
Sherwood III	200	150	In service
Sherwood IV	200	200	In service
Sherwood V	200	200	In service
Sherwood VI	200	200	Second Quarter 2015
Sherwood VII	200	200	Second Quarter 2016

Marcellus Shale Total	1,400	1,350	
Utica Shale:			
Seneca I	200	150	In service
Seneca II(1)	200	50	In service
Seneca III	200	200	In service
Seneca IV	200	200	Second Quarter 2015
Utica Shale Total	800	600	

(1) We have 50 MMcf/d of firm processing capacity at the Seneca II processing facility through the term of our agreement with MarkWest. We have an additional 50 MMcf/d of interim capacity at the Seneca II processing facility until the second quarter of 2015, the Seneca IV in-service date.

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Transportation and Takeaway Capacity

Our primary firm transportation commitments include the following:

· We have entered into firm transportation agreements with various pipelines that enable us to deliver natural gas to the Midwest, Gulf Coast, Eastern Regional, and Mid-Atlantic markets.

· We have several firm transportation contracts with pipelines that have capacity to deliver natural gas to the Chicago and Michigan markets. The Chicago directed pipelines include the Midwestern Gas Transmission pipeline ("MGT"), the Natural Gas Pipeline Company of America pipeline ("NGPL"), and the ANR Pipeline Company pipeline ("ANR-Chicago"), via interconnects with the Rockies Express Pipeline ("REX").

o The firm transportation contract on REX provides firm capacity for 600,000 MMBtu per day. We have 165,000 MMBtu per day of firm transportation on MGT which will increase by an additional 125,000 MMBtu per day in November 2015. We have 235,000 MMBtu per day of firm transportation on NGPL which will increase by 75,000 MMBtu per day in November 2016. We also have 200,000 MMBtu per day of firm transportation on ANR-Chicago to deliver natural gas to Chicago in the summer and Michigan in the winter. The contracts expire at various dates from 2021 through 2034.

· To access the Gulf Coast market and Eastern Regional market, we have firm transportation contracts with various pipelines. These contracts include firm capacity on the Columbia Gas Transmission pipeline ("TCO"), Columbia Gulf Transmission pipeline ("Columbia Gulf"), Tennessee Gas Pipeline Company pipeline ("Tennessee"), ANR Pipeline Company pipeline ("ANR-Gulf"), and Equitrans pipeline ("EQT"). This diverse portfolio of firm capacity gives us the flexibility to move natural gas to favorably priced markets.

o We have several firm transportation contracts on TCO for volumes that total to approximately 582,000 MMBtu per day. Of the 582,000 MMBtu per day of firm capacity on TCO, we have the ability to utilize 530,000 MMbtu per day of capacity on Columbia Gulf, which provides access to the Gulf Coast markets. These contracts expire at various dates from 2017 through 2025.

o We have a firm transportation contract with TCO to transport natural gas in the western and eastern direction on TCO's WB system. The firm transportation contract on TCO's WB system provides firm capacity in the western direction for volumes that increase from 590,000 MMBtu per day in November 2015 to 790,000 MMBtu per day in November 2017. This west directed firm capacity provides access to the Gulf Coast market via the Tennessee pipeline. The transportation contract on TCO's WB system also provides firm capacity in the eastern direction to a purchaser under a firm sales contract at the Loudoun, VA delivery point for ultimate delivery to the Cove Point LNG facility for 330,000 MMBtu per day upon the in-service date of the facility, estimated to be the fourth quarter of 2017. These contracts expire at various dates from 2030 through 2037.

o We have a firm transportation contract for 600,000 MMBtu per day beginning in April 2015 on ANR-Gulf to deliver natural gas from Ohio to the Gulf Coast markets. This contract expires in 2045.

o We have a firm transportation contract for 800,000 MMBtu per day estimated to be in-service in late 2016 or early 2017 on the Energy Transfer Rover Pipeline which will connect the Marcellus and Utica Shale assets to Midwest and Gulf Coast markets, or for export to Canadian markets via our existing firm transportation on ANR Chicago and ANR Gulf. This contract expires in 2031.

o We have firm transportation contracts for volumes that increase from 192,000 MMBtu per day in late 2014 to 250,000 MMBtu per day in July 2015 on EQT to deliver Marcellus natural gas to other various delivery points in the Appalachian Basin. The contracts expire at various dates from 2021 through 2025.

· We have a firm transportation contract for 20,000 Bbl per day on the Enterprise Products Partners ATEX pipeline ("ATEX"), to take ethane from Appalachia to Mont Belvieu, Texas. The ATEX firm transportation commitment expires in 2028.

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· We have firm transportation contracts for 11,500 Bbl per day of ethane and for 50,000 Bbl per day of propane or butane on the Sunoco pipeline (or "Mariner East 2"), from Houston, Pennsylvania to Marcus Hook near Philadelphia, PA. The expected in-service date of Mariner East 2 is late 2016. These contracts expire on the tenth anniversary from the in-service date. The Mariner East 2 provides access to international markets via trans ocean cargo carriers.

Under firm transportation contracts, we are obligated to deliver minimum daily volumes or pay fees for any deficiencies in deliveries. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Debt Agreements and Contractual Obligations" for information on our minimum fees for such contracts. Based on current projected 2015 annual production levels, we estimate that we could incur marketing expense pf $100 million to $150 million for unused and un-marketed transportation capacity. We continue to actively market any excess capacity in order to offset minimum commitment fees.

Fresh Water Distribution

We own two independent fresh water distribution systems that distribute fresh water from the Ohio River and several regional water sources for well completion operations in the Marcellus and Utica Shales. These systems consist of permanent buried pipelines, movable surface pipelines and fresh water storage facilitates, as well as pumping stations to transport the fresh water throughout the pipeline networks. To the extent necessary, we move surface pipelines to well pads for service completion operations in concert with our drilling program. As of December 31, 2014, we have the ability to store a total of 3.5 million barrels of fresh water in 30 impoundments. We believe our water distribution system eliminated over 400,000 water truck trips in our operating areas during 2014.

Due to the extensive geographic distribution of our water pipeline systems in both West Virginia and Ohio, we have provided water delivery services to a neighboring oil and gas producer within and adjacent to our operating area, and are able to provide water delivery services to other oil and gas producers in the area, subject to commercial arrangements, in an effort to further reduce water truck traffic.

As of December 31, 2014 in West Virginia, we owned and operated 103 miles of buried fresh water pipelines that service our drilling activities in the Marcellus Shale, as well as 22 centralized water storage facilities equipped with transfer pumps. As of December 31, 2014 in Ohio, we owned and operated 49 miles of buried fresh water pipelines that service our drilling activities in the Utica Shale, as well as 8 centralized water storage facilities equipped with transfer pumps.

In connection with the Antero Midstream IPO, we granted Antero Midstream an option to purchase our fresh water distribution systems at fair market value.

Major Customers

For the year ended December 31, 2014, sales to South Jersey Resources Group LLC, Sequent Energy Management L.P., and Nextera Energy Powermarketing LLC represented 29%, 16%, and 12% of our total sales, respectively. For the year ended December 31, 2013, sales to South Jersey Resources Group LLC, Sequent Energy Management L.P., and Nextera Energy Powermarketing LLC represented 30%, 14%, and 8% of our total sales, respectively. For the year ended December 31, 2012, sales to South Jersey Resources Group, LLC, Nextera Energy Powermarketing LLC and Dominion Field Services Inc. represented 23%, 13% and 10% of our total sales, respectively. Although a substantial portion of our production is purchased by these major customers, we do not believe the loss of any one or several customers would have a material adverse effect on our business, as we believe other customers or markets would be accessible to us.

Title to Properties

We believe that we have satisfactory title to all of our producing properties in accordance with generally accepted industry standards. As is customary in the industry, often in the case of undeveloped properties, cursory investigation of record title is made at the time of lease acquisition. Investigations are made before the consummation of an acquisition of producing properties and before commencement of drilling operations on undeveloped properties. Individual properties may be subject to burdens that we believe do not materially interfere with the use, or affect the value of, the properties. Burdens on properties may include:

- customary royalty interests;
- liens incident to operating agreements and for current taxes;

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- obligations or duties under applicable laws;
- development obligations under natural gas leases; or
- net profits interests.

Seasonality

Demand for natural gas generally decreases during the spring and fall months and increases during the summer and winter months. However, seasonal anomalies such as mild winters or mild summers sometimes lessen this fluctuation. Cold winters such as that experienced in 2013 2014 can significantly increase demand and price fluctuations. 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. These seasonal anomalies can increase competition for equipment, supplies and personnel during the spring and summer months, which could lead to shortages and increase costs or delay our operations.

Competition

The oil and natural gas industry is intensely competitive, and we compete with other companies in our industry that have greater resources than we do. Many of these companies not only explore for and produce natural gas, but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for productive natural gas properties and exploratory prospects or define, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit, and may be able to expend greater resources to attract and maintain industry personnel. In addition, these companies may have a greater ability to continue exploration activities during periods of low natural gas market prices. Our larger competitors may be able to absorb the burden of existing, and any changes to, federal, state and local laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. In addition, because we have fewer financial and human resources than many companies in our industry, we may be at a disadvantage in bidding for exploratory prospects and producing natural gas properties.

Regulation of the Oil and Natural Gas Industry

General

Our oil and natural gas operations are subject to extensive, and frequently changing, laws and regulations related to the production, transportation and sale of oil, natural gas and NGLs. We believe we are in substantial compliance with currently applicable laws and regulations and that continued substantial compliance with existing requirements will not have a material adverse effect on our financial position, cash flows or results of operations. However, such laws and regulations are frequently amended or reinterpreted. Additional proposals and proceedings that affect the oil and natural gas industries are regularly considered by Congress, federal agencies, the states, and the courts. We cannot predict when or whether any such proposals may become effective. Therefore, we are unable to predict the future costs or impact of compliance. The regulatory burden on the industry increases the cost of doing business and affects profitability. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers, gatherers and marketers with which we compete.

Regulation of Production of Natural Gas and Oil

We own interests in properties located onshore in three U.S. states, and our production activities on these properties are subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. These statutes and regulations address requirements related to permits for drilling of wells, bonding to drill or operate wells, the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled, sourcing and disposal of water used in the drilling and completion process, the plugging and abandonment of wells, venting or flaring of natural gas, and the ratability or fair apportionment of production from fields and individual wells. In addition, all of the states in which we own and operate properties have regulations governing environmental and conservation matters, including provisions for the handling and disposing or discharge of waste materials, the unitization or pooling of natural gas and oil properties, the establishment of maximum allowable rates of production from natural gas and oil wells, and the size of drilling and spacing units or proration units and the density of wells that may be drilled. Some states also have the power to prorate production to the market demand for oil and gas. The

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effect of these regulations is to limit the amount of natural gas and oil that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing or density. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas, and NGLs within its jurisdiction.

The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Regulation of Transportation of Natural Gas

The transportation and sale for resale of natural gas in interstate commerce are regulated by the Federal Energy Regulatory Commission, or FERC, under the Natural Gas Act of 1938, or NGA, the Natural Gas Policy Act of 1978, or NGPA, and regulations issued under those statutes. FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non discriminatory basis. Although FERC's orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by FERC as a natural gas company under the NGA. Although FERC has not made any formal determinations with respect to any of our facilities, we believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. The distinction between FERC regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and FERC determines whether facilities are gathering facilities on a case by case basis, so the classification and regulation of our gathering facilities may be subject to change based on future determinations by FERC, the courts or Congress. State regulation of natural gas gathering facilities generally include various safety, environmental and, in some circumstances, nondiscriminatory take requirements. Although such regulation has not generally been affirmatively applied by state agencies, natural gas gathering may receive greater regulatory scrutiny in the future.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Regulation of Sales of Natural Gas, NGLs, and Oil

The prices at which we sell natural gas, NGLs, and oil is not currently subject to federal regulation and, for the most part, is not subject to state regulation. FERC, however, regulates interstate natural gas transportation rates, and terms and conditions of transportation service, which affects the marketing of the natural gas we produce, as well as the prices we receive for sales of our natural gas. Similarly, the price we receive from the sale of oil and NGLs is affected by the cost of transporting those products to market. FERC regulates the transportation of oil and liquids on interstate pipelines under the provision of the Interstate Commerce Act, the Energy Policy Act of 1992 and regulations issued under those statutes. Intrastate transportation of oil, NGLs, and other products, is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes. In addition, while sales by producers of natural gas and all sales of crude oil, condensate, and NGLs can currently be made at uncontrolled market prices, Congress could reenact price controls in the future.

With regard to our physical 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 FERC as described below, the U.S. Commodity Futures Trading Commission under Commodity Exchange Act, or CEA, and the Federal Trade Commission, or FTC. We are also subject to various reporting requirements that are designed to facilitate transparency and prevent market manipulation. Should we violate the anti-market manipulation laws and regulations, we could be subject to fines and penalties as well as related third party damage claims by, among others, market participants, sellers, royalty owners and taxing authorities.

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The Domenici Barton Energy Policy Act of 2005, or EPAct of 2005 amended the NGA to add an anti market manipulation provision which makes it unlawful for any entity to engage in prohibited behavior to be prescribed by FERC, and furthermore provided FERC with additional civil penalty authority. In Order No. 670, FERC promulgated rules implementing the anti market manipulation provision of the EPAct of 2005, which make it unlawful to: (1) 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, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; (2) to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or (3) to engage in any act or practice that operates as a fraud or deceit upon any person. The anti market manipulation rules do not apply to activities that relate only to intrastate or other non jurisdictional sales or gathering, but does apply to activities of gas pipelines and storage companies that provide interstate services, as well as otherwise non jurisdictional entities to the extent the activities are conducted "in connection with" gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order No. 704 described below. Under the EPAct of 2005, FERC has the power to assess civil penalties of up to $1,000,000 per day for each violation of the NGA and the NGPA.

Under Order No. 704, wholesale buyers and sellers of more than 2.2 million MMBtus of physical natural gas in the previous calendar year, including interstate and intrastate natural gas pipelines, natural gas gatherers, natural gas processors, natural gas marketers and natural gas producers are required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. Order 704 also requires market participants to indicate whether they report prices to any index publishers, and if so, whether their reporting complies with FERC's policy statement on price reporting.

The CEA prohibits any person from manipulating or attempting to manipulate the price of any commodity in interstate commerce or futures on such commodity. The CEA also prohibits knowingly delivering or causing to be delivered false or misleading or knowingly inaccurate reports concerning market information or conditions that affect or tend to affect the price of a commodity. In November 2009, the FTC issued regulations pursuant to the Energy Independence and Security Act of 2007 intended to prohibit market manipulation in the petroleum industry. Violators of the regulations face civil penalties of up to $1,000,000 per violation per day. Together with FERC, these agencies have imposed broad rules and regulations prohibiting fraud and manipulation in oil and gas markets and energy futures markets.

Changes in law and to FERC policies and regulations may adversely affect the availability and reliability of firm and/or interruptible transportation service on interstate pipelines, and we cannot predict what future action FERC will take. We do not believe, however, that any regulatory changes will affect us in a way that materially differs from the way they will affect other natural gas producers, gatherers and marketers with which we compete.

Regulation of Environmental and Occupational Safety and Health Matters

Our natural gas, NGLs, and oil exploration and production operations are subject to numerous stringent federal, regional, state and local statutes and regulations governing occupational safety and health and the discharge of materials into the environment or otherwise relating to environmental protection, some of which carry substantial administrative, civil and criminal penalties for failure to comply. These laws and regulations may require the acquisition of a permit before drilling or other regulated activity commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transporting through pipelines, govern the sourcing and disposal of water used in the drilling and completion process, limit or prohibit drilling activities in certain areas and on certain lands lying within wilderness, wetlands, frontier and other protected areas, require some form of remedial action to prevent or mitigate pollution from former operations such as plugging abandoned wells or closing earthen pits, establish specific safety and health criteria addressing worker protection and impose substantial liabilities for pollution resulting from operations or failure to comply with applicable laws and regulations. In addition, these laws and regulations may restrict the rate of production.

The following is a summary of the more significant existing environmental and occupational health and safety laws and regulations, as amended from time to time, to which our business operations are subject and for which compliance may have a material adverse impact on our capital expenditures, results of operations or financial position.

Hazardous Substances and Waste Handling

The Comprehensive Environmental Response, Compensation, and Liability Act, or CERCLA, also known as the "Superfund" law, and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that are considered to have contributed to the release of a "hazardous substance" into the environment. These persons include the current and past owner or operator of the disposal site or the site where the release occurred and companies that disposed or arranged for the disposal of the hazardous substances at the site where the release occurred. Under CERCLA, such persons may be subject to joint and several strict liability for the costs of cleaning up the hazardous substances that have been released into the environment and for damages to natural resources, and it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment. We are able to control directly the operation of only those wells with respect to which we act as operator. Notwithstanding our lack of direct control over wells operated by others, the failure of an operator other than us to comply with applicable environmental regulations may, in certain circumstances, be attributed to us as owners under CERCLA. In addition, despite the "petroleum exclusion" of Section 101(14) of CERCLA, which currently encompasses crude oil and natural gas, we generate materials in the course of our operations that may be regulated as hazardous substances; however, we are unaware of any liabilities for which we may be held responsible that would materially and adversely affect us.

The Resource Conservation and Recovery Act, or RCRA, and analogous state laws, impose detailed requirements for the generation, handling, storage, treatment and disposal of nonhazardous and hazardous solid wastes. RCRA specifically excludes drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy from regulation as hazardous wastes. However, these wastes may be regulated by the U.S. Environmental Protection Agency, or the EPA, or state agencies under RCRA's less stringent nonhazardous solid waste provisions, state laws or other federal laws. Moreover, it is possible that these particular oil and natural gas exploration, development and production wastes now classified as nonhazardous solid wastes could be classified as hazardous wastes in the future. A loss of the RCRA exclusion for drilling fluids, produced waters and related wastes could result in an increase in our costs to manage and dispose of generated wastes, which could have a material adverse effect on our results of operations and financial position. In addition, in the course of our operations, we generate some amounts of ordinary industrial wastes, such as waste solvents, laboratory wastes and waste compressor oils that may become regulated as hazardous wastes if such wastes have hazardous characteristics. Although the costs of managing hazardous waste may be significant, we do not believe that our costs in this regard are materially more burdensome than those for similarly situated companies.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production activities for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes, or petroleum hydrocarbons may have been released on, under or from the properties owned or leased by us, or on, under or from other locations, including off site locations, where such substances have been taken for recycling or disposal. In addition, some of our 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, under or from them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to undertake response or corrective measures, which could include removal of previously disposed substances and wastes, cleanup of contaminated property or performance of remedial plugging or waste pit closure operations to prevent future contamination.

Water Discharges

The Federal Water Pollution Control Act, or the Clean Water Act, and comparable state laws impose restrictions and strict controls regarding the discharge of pollutants, including produced waters and other oil and natural gas wastes, into federal and state waters. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or the state. The discharge of dredge and fill material in regulated waters, including wetlands, is also prohibited, unless authorized by a permit issued by the U.S. Army Corps of Engineers. Obtaining permits has the potential to delay the development of natural gas and oil projects. These laws and any implementing regulations provide for administrative, civil and criminal penalties for any unauthorized discharges of oil and other substances in reportable quantities and may impose substantial potential liability for the costs of removal, remediation and damages.

Pursuant to these laws and regulations, we may be required to obtain and maintain approvals or permits for the discharge of wastewater or storm water and are required to develop and implement spill prevention, control and countermeasure plans, also referred to as “SPCC plans,” in connection with on site storage of significant quantities of oil. We believe that we maintain all required discharge permits necessary to conduct our operations, and further believe we are in substantial compliance with the terms thereof. We are currently undertaking a review of recently acquired natural gas properties to determine the need for new or updated SPCC plans and, where necessary, we will be developing or upgrading such plans implementing the physical and operation controls imposed by these plans, the costs of which are not expected to be substantial.

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Air Emissions

The federal Clean Air Act and comparable state laws restrict the emission of air pollutants from many sources, such as, for example, compressor stations, through air emissions standards, construction and operating permitting programs and the imposition of other compliance requirements. These laws and regulations may require us to obtain pre approval for the construction or modification of certain projects or facilities expected to produce or significantly increase air emissions, obtain and strictly comply with stringent air permit requirements or utilize specific equipment or technologies to control emissions of certain pollutants. The need to obtain permits has the potential to delay the development of oil and natural gas projects. Over the next several years, we may be required to incur certain capital expenditures for air pollution control equipment or other air emissions related issues. The EPA has issued final rules under the Clean Air Act that subject oil and natural gas production, processing, transmission and storage operations to regulation under the New Source Performance Standards, or NSPS, and National Emission Standards for Hazardous Air Pollutants, or NESHAP, programs. These rules restrict volatile organic compound emissions from three subcategories of fractured and refractured 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 refractured 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. However, the "other" wells must use reduced emission completions, also known as "green completions," with or without combustion devices. These regulations also establish specific new requirements regarding emissions from production related wet seal and reciprocating compressors, pneumatic controllers and storage vessels. Compliance with these and other air pollution control and permitting requirements has the potential to delay the development of natural gas and oil projects and increase our costs of development and production, which costs could be significant. However, we do not believe that compliance with such requirements will have a material adverse effect on our operations.

Regulation of "Greenhouse Gas" Emissions

In response to findings that emissions of carbon dioxide, methane and other greenhouse gases, or GHGs, present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish PSD (Prevention of Significant Deterioration) construction and Title V operating permit reviews for certain large stationary sources. 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 sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations. Recently, the EPA finalized modifications to its GHG reporting rules that would require covered entities to report emissions on an individual GHG basis. In addition, the EPA has proposed a rule that would expand the agency's reporting requirements to cover completions and workovers from hydraulically fractured oil wells. These changes to EPA's GHG emissions reporting rule could result in increased compliance costs. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Severe limitations on GHG emissions could also 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 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 event; if any such effects were to occur, they could have an adverse effect on our exploration and production operations.

Hydraulic Fracturing Activities

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

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through a cased and cemented wellbore into targeted subsurface formations to fracture the surrounding rock and stimulate production. We regularly use hydraulic fracturing as part of our operations as does most of the domestic oil and natural gas industry. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the federal Safe Drinking Water Act, or the SDWA, over certain hydraulic fracturing activities involving the use of diesel fuels and issued permitting guidance in February 2014 regarding the use of diesel fuels in hydraulic fracturing fluids. Also, in May 2014, the EPA proposed rules under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing.

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, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and 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 fracturing activities in particular. Some states and municipalities have sought to ban hydraulic fracturing altogether. 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, 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.

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 and a draft 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 sometime in the first half of 2015. 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 sometime in 2015. In addition, the U.S. Department of the Interior published a revised proposed rule in May 2013 that would implement updated requirements for hydraulic fracturing activities on federal lands, including new requirements relating to public disclosure, well bore integrity and handling of flowback water. Other governmental agencies, including the U.S. Department of Energy 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 SDWA or other regulatory mechanisms. In addition, the Obama Administration is expected to release a series of new regulations on the oil and gas industry in 2015, including federal standards limiting methane emissions.

Occupational Safety and Health Act

We are also subject to the requirements of the federal Occupational Safety and Health Act, as amended, or OSHA, and comparable state laws that regulate the protection of the health and safety of employees. In addition, OSHA's hazard communication standard, the Emergency Planning and Community Right to Know Act and implementing regulations and similar state statutes and regulations require that information be maintained about hazardous materials used or produced in our operations and that this information be provided to employees, state and local government authorities and citizens. We believe that our operations are in substantial compliance with the applicable worker health and safety requirements.

Endangered Species Act

The federal Endangered Species Act, or ESA, was established to protect endangered and threatened species. Pursuant to the ESA, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. We conduct operations on natural gas and oil leases in areas where certain species that are listed as threatened or endangered are known to exist and where other species, such as the northern long eared bat, that potentially could be listed as threatened or endangered under the ESA may exist. The U.S. Fish and Wildlife Service may designate critical habitat and suitable habitat areas that it believes are necessary for survival of a threatened or endangered species. A critical habitat or suitable habitat designation could result in further material restrictions to federal land use and may materially delay or prohibit land access for natural gas and oil development. Moreover, as a result of a settlement, 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 by no later than completion of the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where underlying property operations are conducted could cause us to incur increased costs arising from species protection measures or could result in limitations on our exploration and production activities that could have an adverse

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impact on our ability to develop and produce reserves. If we were to have a portion of our leases designated as critical or suitable habitat, it could adversely impact the value of our leases.

In summary, we believe we are in substantial compliance with currently applicable environmental laws and regulations. Although we have not experienced any material adverse effect from compliance with environmental requirements, there is no assurance that this will continue. We did not have any material capital or other non recurring expenditures in connection with complying with environmental laws or environmental remediation matters in 2014, nor do we anticipate that such expenditures will be material in 2015.

Employees

As of December 31, 2014, we had 444 full time employees, including 48 in executive, finance, treasury and administration, 19 in geology, 168 in production and engineering, 70 in midstream, 87 in land, and 52 in accounting. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be satisfactory. We utilize the services of independent contractors to perform various field and other services.

Address, Internet Website and Availability of Public Filings

Our principal executive offices are located at 1615 Wynkoop Street, Denver, Colorado 80202 and our telephone number is (303) 357 7310. Our website is located at www.anteroresources.com.

We furnish or file with the Securities and Exchange Commission (the “SEC”) our Annual Reports on Form 10 K, our Quarterly Reports on Form 10 Q, and our Current Reports on Form 8 K. We make these documents available at www.anteroresources.com under the “Investors Relations” link as soon as reasonably practicable after they are filed with the SEC.

Information on our website is not incorporated into this Annual Report on Form 10 K or our other filings with the SEC and is not a part of our other filings.

Item 1A. Risk Factors

Our business involves a high degree of risk. If any of the following risks, or any risk described elsewhere in this Annual Report on Form 10 K, actually occur, our business, financial condition or results of operations could suffer.

Natural gas, NGLs, and oil prices are volatile. A substantial or extended decline in commodity prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The prices we receive for our natural gas, NGLs, and oil production heavily influence our revenue, profitability, access to capital and future rate of growth. Natural gas, NGLs, and oil are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the commodities market has been volatile. This market will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for natural gas, NGLs and oil;

- the price and quantity of imports of foreign natural gas, including liquefied natural gas;
- political conditions in or affecting other producing countries, including conflicts in the Middle East, Africa, South America and Russia;
- the level of global exploration and production;
- the level of global inventories;
- prevailing prices on local price indexes in the areas in which we operate;

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- localized and global supply and demand fundamentals and transportation availability;
- weather conditions;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- domestic, local and foreign governmental regulation and taxes.

Recently, global energy commodity prices have declined precipitously as a result of several factors including increased worldwide supplies, a stronger U.S. dollar, relatively mild weather in the U.S., and strong competition among oil producing countries for market share. Specifically, prices for WTI have declined from approximately $106.00 per Bbl in June 2014 to less than $50.00 per Bbl in January 2015. Henry Hub natural gas has traded around $3.00 per MMBtu in January 2015 compared to prices a year ago in January 2014 of around $4.40 per MMBtu.

Lower commodity prices reduce our cash flows and borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our reserves as existing reserves are depleted. Lower commodity prices may also reduce the amount of natural gas, NGLs and oil that we can produce economically.

If commodity prices further decrease, a significant portion of our exploitation, development and exploration projects could become uneconomic. This may result in our having to make significant downward adjustments to our estimated proved reserves. As a result, a substantial or extended decline in commodity prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

Our exploitation, development, and exploration projects require substantial capital expenditures. We may be unable to obtain required capital or financing on satisfactory terms, which could lead to a decline in our natural gas reserves.

The natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the exploitation, development, and acquisition of natural gas reserves. Our cash flow used in investing activities related to capital and exploration expenditures was approximately $4.1 billion in 2014. Our board of directors has approved a capital budget for 2015 of $1.8 billion that includes $1.6 billion for drilling and completion, $50 million for fresh water distribution and $150 million for core leasehold acreage acquisitions. Our capital budget excludes acquisitions. We expect to fund these capital expenditures with cash generated by operations and borrowings under our revolving credit facility or capital market transactions; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities or the sale of assets. The actual amount and timing of our future capital expenditures may differ materially from our estimates as a result of, among other things, commodity prices, actual drilling results, the availability of drilling rigs and other services and equipment, and regulatory, technological, and competitive developments. A further reduction in commodity prices from current levels may result in an additional decrease in our actual capital expenditures, which would negatively impact our ability to grow production. For additional discussion of the risks regarding our ability to obtain funding, please read “Item 1A. Risk Factors – The borrowing base under our revolving credit facility is subject to semi-annual redetermination by our lenders, which could result in a reduction of our borrowing base. This may hinder or prevent us from meeting our future capital needs.” The issuance of additional indebtedness would require that a portion of our cash flow from operations be used for the payment of interest and principal on our indebtedness, thereby reducing our ability to use cash flow from operations to fund working capital, capital expenditures and acquisitions.

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

- our proved reserves;
- the level of hydrocarbons we are able to produce from existing wells;
- the prices at which our production is sold;
- our ability to acquire, locate and produce new reserves; and

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- our ability to borrow under our revolving credit facility, including any potential decrease in the borrowing base.

If our revenues or the borrowing base under our revolving credit facility decrease as a result of lower natural gas prices, operating difficulties, declines in reserves or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. If additional capital is needed, we may not be able to obtain debt or equity financing on terms acceptable to us, if at all. If cash flow generated by our operations or available borrowings under our revolving credit facility are not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to development of our properties, which in turn could lead to a decline in our reserves and production, and could adversely affect our business, financial condition and results of operations.

Drilling for and producing natural gas are high risk activities with many uncertainties that could adversely affect our business, financial condition or results of operations.

Our future financial condition and results of operations will depend on the success of our exploitation, development and acquisition activities, which are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. For a discussion of the uncertainty involved in these processes, see "—Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves." In addition, our cost of drilling, completing and operating wells is often uncertain before drilling commences.

Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- further or prolonged declines in oil, NGLs, and natural gas prices;
- limitations in the market for oil, NGLs, and natural gas;
- delays imposed by or resulting from compliance with regulatory requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel or in obtaining water for hydraulic fracturing activities;
- equipment failures or accidents;
- adverse weather conditions, such as blizzards, tornados, hurricanes and ice storms;
- issues related to compliance with environmental regulations;
- environmental hazards, such as natural gas leaks, 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 surface and subsurface environment;
- limited availability of financing at acceptable terms; and
- title problems.

We may not be able to generate sufficient cash to service all of our indebtedness and may be forced to take other actions to satisfy our obligations under our indebtedness, which may not be successful.

Our ability to make scheduled payments on or to refinance our indebtedness obligations, including our revolving credit facility and our senior notes depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. We may not be able to maintain a

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level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness, including the senior notes.

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

The borrowing base under our revolving credit facility may be reduced in light of recent commodity price declines, which could hinder or prevent us from meeting our future capital needs.

The borrowing base under our revolving credit facility is currently $4.0 billion, and lender commitments under our revolving credit facility are $4.0 billion. Our borrowing base is redetermined by the lenders twice per year, and the next scheduled borrowing base redetermination is expected to occur in October 2015. Our borrowing base may decrease as a result of lower oil or natural gas prices, operating difficulties, declines in reserves, lending requirements or regulations, the issuance of new indebtedness or for any other reason. We cannot be certain that funding will be available if needed, and to the extent required, on acceptable terms. In the event of a decrease in our borrowing base due to declines in commodity prices or otherwise, we may be unable to meet our obligations as they come due and could be required to repay any indebtedness in excess of the redetermined borrowing base. In addition, we may be unable to access the equity or debt capital markets, including the market for senior unsecured notes, to meet our obligations. As a result, we may be unable to implement our drilling and development plan, make acquisitions or otherwise carry out our business plan, which would have a material adverse effect on our financial condition and results of operations and impair our ability to service our indebtedness.

We are required to pay fees to our service providers based on minimum volumes under long-term contracts regardless of actual volume throughput.

We have various firm transportation and gas processing, gathering and compression service agreements in place, each with minimum volume delivery commitments. Lower commodity prices may lead to reductions in our drilling program, which may result in insufficient production to utilize our full firm transportation capacity. Our firm transportation agreements expire at various dates from 2018 to 2045, and our gas processing, gathering, and compression services agreements expire at various dates from 2016 to 2027. We are obligated to pay fees on minimum volumes to our service providers regardless of actual volume throughput. As of December 31, 2014, our long term contractual obligations under agreements with minimum volume commitments totaled approximately $16 billion over the term of the contracts. If we have insufficient production to meet the minimum volumes, our cash flow from operations will be reduced, which may require us to reduce or delay our planned investments and capital expenditures or seek alternative means of financing all of which may have a material adverse effect on our results or operations.

Based on current projected 2015 annual production levels, we estimate that we could incur marketing expense of $100 million to $150 million for unused and un-marketed transportation capacity.

Restrictions in our existing and future debt agreements could limit our growth and our ability to engage in certain activities.

Our revolving credit facility contains a number of significant covenants (in addition to covenants restricting the incurrence of additional indebtedness), including restrictive covenants that may limit our ability to, among other things:

- sell assets;

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- make loans to others;
- make investments;
- enter into mergers;
- make certain payments;
- hedge future production;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

The indentures governing our senior notes contain similar restrictive covenants. In addition, our revolving credit facility requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. These restrictions, together with those in the indentures governing our senior notes, may also limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under the indentures governing our senior notes and our revolving credit facility impose on us.

Our revolving credit facility limits the amounts we can borrow up to a borrowing base amount, which the lenders, in their sole discretion, determine on a semi annual basis based upon projected revenues from the natural gas properties securing our loan. The lenders can unilaterally adjust the borrowing base and the borrowings permitted to be outstanding under our revolving credit facility. Any increase in the borrowing base requires the consent of the lenders holding 100% of the commitments. If the requisite number of lenders do not agree to an increase, then the borrowing base will be the lowest borrowing base acceptable to such lenders. For additional discussion of the risks regarding our ability to obtain funding under our revolving credit facility, please read "Item 1A. Risk Factors – A sustained decline of oil and natural gas prices may affect our ability to obtain funding, obtain funding on acceptable terms or obtain funding under our revolving credit facility. This may hinder or prevent us from meeting our future capital needs."

A breach of any covenant in our revolving credit facility would result in a default under that agreement after any applicable grace periods. A default, if not waived, could result in acceleration of the indebtedness outstanding under the facility and in a default with respect to, and an acceleration of, the indebtedness outstanding under other debt agreements. The accelerated indebtedness would become immediately due and payable. If that occurs, we may not be able to make all of the required payments or borrow sufficient funds to refinance such indebtedness. Even if new financing were available at that time, it may not be on terms that are acceptable to us.

Currently, we receive significant incremental cash flows as a result of our hedging activity. To the extent we are unable to obtain future hedges at effective prices consistent with those we have received to date and natural gas prices do not improve, our cash flows may be adversely impacted. Additionally, if development drilling costs increase significantly in the future, our hedged revenues may not be sufficient to cover our costs.

To achieve more predictable cash flows and reduce our exposure to downward price fluctuations, as of December 31, 2014, we had entered into a number of hedge contracts for approximately 1.8 Tcfe of our projected natural gas, NGLs, and oil production through December 31, 2020. We are currently realizing a significant benefit from these hedge positions. For example, for the years ended December 31, 2013 and 2014, we received approximately $164 million and $136 million, respectively, in revenues from cash settled derivatives pursuant to our hedges, which represented approximately 13% and 5%, respectively, of our total revenues for such periods. Many of the hedge agreements that resulted in these realized gains for the years ended December 31, 2013 and 2014 were executed at times when spot and future prices were higher than prices that we are currently able to obtain in the futures market, and the price at which we have been able to hedge future production has decreased as a result. A sustained decrease in commodity prices may adversely affect our ability hedge future production, particularly on a local basis. If we are unable to enter into new hedge contracts in the future at favorable pricing and for a sufficient amount of our production, our financial condition and results of operations could be materially adversely affected.

Additionally, since we hedge a significant part of our estimated future production, we have fixed a significant part of our future revenue stream. For example, for the years ended December 31, 2013 and 2014, approximately 81% and 73%, respectively, of

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our production was covered by our hedge contracts. If development drilling costs increase significantly because of inflation, increased demand for oilfield services, increased costs to comply with regulations governing our industry or other factors, future hedged revenues may not be sufficient to cover our costs.

In certain circumstances we may have to make cash payments under our hedging arrangements and these payments could be significant.

If natural gas or oil prices exceed the price at which we have hedged our commodities, we will be obligated to make cash payments to our hedge counterparties, which could, in certain circumstances, be significant. As of December 31, 2014, we had entered into hedging contracts through December 31, 2020 covering a total of approximately 1.8 Tcfe of our projected natural gas, NGLs, and oil production at a weighted average price of $4.43 per Mcfe. If we have to post cash collateral to meet our obligations under such arrangements, our cash otherwise available for use in our operations would be reduced.

Our derivative activities could result in financial losses or could reduce our earnings.

To achieve more predictable cash flows and reduce our exposure to adverse fluctuations in the prices of natural gas, we enter into derivative instrument contracts for a significant portion of our natural gas production, including fixed price swaps. As of December 31, 2014, we had entered into hedging contracts through December 31, 2020 covering a total of approximately 1.8 Tcfe of our projected natural gas, NGLs, and oil production at an average index price of $4.43 per MMBtu. Accordingly, our earnings may fluctuate significantly as a result of changes in fair value of our derivative instruments.

Derivative instruments also expose us to the risk of financial loss in some circumstances, including when:

- the counterparty to the derivative instrument defaults on its contractual obligations;
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received; or
- there are issues with regard to legal enforceability of such instruments.

The use of derivatives may, in some cases, require the posting of cash collateral with counterparties. If we enter into derivative instruments that require cash collateral and commodity prices or interest rates change in a manner adverse to us, our cash otherwise available for use in our operations would be reduced which could limit our ability to make future capital expenditures and make payments on our indebtedness, and which could also limit the size of our borrowing base. Future collateral requirements will depend on arrangements with our counterparties, highly volatile oil and natural gas prices and interest rates.

In addition, derivative arrangements could limit the benefit we would receive from increases in the prices for natural gas, which could also have an adverse effect on our financial condition.

Our hedging transactions expose us to counterparty credit risk.

As of December 31, 2014, the estimated fair value of our commodity derivative contracts was approximately $1.6 billion. Any default by the counterparties to these derivative contracts when they become due would have a material adverse effect on our financial condition and results of operations. The fair value of our commodity derivative contracts at December 31, 2014 includes the following values by bank counterparty: Credit Suisse—$268 million; Barclays—$257 million; JP Morgan—$253 million; BNP Paribas—$233 million; Citigroup—$231 million; Wells Fargo—$211 million; Scotiabank—$77 million; Fifth Third Bank—$31 million; Toronto Dominion Bank—$28 million; Bank of Montreal—$4 million. The credit ratings of certain of these banks have been downgraded because of the sovereign debt crisis in Europe.

Our hedging transactions expose us to risk of financial loss if a counterparty fails to perform under a derivative contract. Disruptions in the financial markets could lead to sudden decreases in a counterparty's liquidity, which could make them unable to perform under the terms of the derivative contract and we may not be able to realize the benefit of the derivative contract.

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Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in our reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating natural gas and oil reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these interpretations or assumptions could materially affect our estimated quantities and present value of our reserves.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary.

The process also requires economic assumptions about matters such as natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds.

Actual future production, natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable natural gas reserves will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of our reserves. In addition, we may adjust our reserve estimates to reflect production history, results of exploration and development, existing commodity prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our reserves is the current market value of our estimated natural gas reserves. We generally base the estimated discounted future net cash flows from our reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate.

Our identified potential well locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling. In addition, we may not be able to raise the substantial amount of capital that would be necessary to drill our potential well locations.

Our management team has specifically identified and scheduled certain well locations as an estimation of our future multi year drilling activities on our existing acreage. These well locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including natural gas and oil prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, gathering system and pipeline transportation constraints, access to and availability of water sourcing and distribution systems, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the numerous potential well locations we have identified will ever be drilled or if we will be able to produce natural gas or oil from these or any other potential well locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the potential locations are obtained, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified.

As of December 31, 2014, we had 5,331 identified potential horizontal well locations. As a result of the limitations described above, we may be unable to drill many of our potential well locations. In addition, we will require significant additional capital over a prolonged period in order to pursue the development of these locations, and we may not be able to raise or generate the capital required to do so. Any drilling activities we are able to conduct on these potential locations may not be successful or result in our ability to add additional proved reserves to our overall proved reserves or may result in a downward revision of our estimated proved reserves, which could have a material adverse effect on our future business and results of operations. For more information on our identified potential well locations, see "Item 1. Business and Properties—Our Properties and Operations—Estimated Proved Reserves—Identification of Potential Well Locations."

Approximately 88% of our net leasehold acreage is undeveloped, and that acreage may not ultimately be developed or become commercially productive, which could cause us to lose rights under our leases as well as have a material adverse effect on our oil and natural gas reserves and future production and, therefore, our future cash flow and income.

Approximately 88% of our net leasehold acreage is undeveloped, or acreage on which wells have not been drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves. In addition, approximately 50% and 79% of our natural gas leases related to our Marcellus and Utica acreage, respectively, require us to drill wells that are commercially productive, and if we are unsuccessful in drilling such wells, we could lose our rights under such leases. Our future oil and natural gas reserves and production and, therefore, our future cash flow and income are highly dependent on successfully developing our undeveloped leasehold acreage.

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Our producing properties are concentrated in the Appalachian Basin, making us vulnerable to risks associated with operating in one major geographic area.

Our producing properties are geographically concentrated in the Appalachian Basin in West Virginia, Ohio and Pennsylvania. At December 31, 2014, all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, water shortages or other drought related conditions or interruption of the processing or transportation of oil, natural gas or NGLs.

Insufficient processing or takeaway capacity in the Appalachian Basin could cause significant fluctuations in our realized natural gas and NGLs prices.

The Appalachian Basin natural gas and NGLs business environment has historically been characterized by periods during which production has surpassed local processing and takeaway capacity, resulting in substantial discounts in the price received. Although additional Appalachian Basin takeaway capacity has been added in recent periods, we do not believe the existing and expected capacity will be sufficient to keep pace with the increased production caused by recent drilling activity in the area. For example, in the past we have experienced capacity constraints in the Marcellus Shale due to delays in the completion of third party gathering and compression infrastructure.

If we are unable to secure additional gathering, compression and processing capacity and long term firm takeaway capacity on major pipelines that are in existence or currently under construction in our core operating area to accommodate our growing production and to manage basis differentials, it could have a material adverse effect on our financial condition and results of operations.

We may incur losses as a result of title defects in the properties in which we invest.

It is our practice in acquiring oil and gas leases or interests not to incur the expense of retaining lawyers to examine the title to the mineral interest at the time of acquisition. Rather, we rely upon the judgment of oil and gas lease brokers or landmen who perform the fieldwork in examining records in the appropriate governmental office before attempting to acquire a lease in a specific mineral interest. Leases in the Appalachian Basin are particularly vulnerable to title deficiencies due the long history of land ownership in the area, resulting in extensive and complex chains of title. Additionally, there are claims against us alleging that certain acquired leases that are held by production are invalid due to production from the producing horizons being insufficient to hold title to the formation rights that we have purchased. The existence of a material title deficiency can render a lease worthless and can adversely affect our results of operations and financial condition. While we do typically obtain title opinions prior to commencing drilling operations on a lease or in a unit, the failure of title may not be discovered until after a well is drilled, in which case we may lose the lease and the right to produce all or a portion of the minerals under the property.

The development of our estimated proved undeveloped reserves may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our estimated proved undeveloped reserves may not be ultimately developed or produced.

At December 31, 2014, 70% of our total estimated proved reserves were classified as proved undeveloped. Our approximately 8.9 Tcfe of estimated proved undeveloped reserves will require an estimated $8.2 billion of development capital over the next five years. Moreover, the development of probable and possible reserves will require additional capital expenditures and such reserves are less certain to be recovered than proved reserves. Development of these undeveloped reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves, increases in costs to drill and develop such reserves, or decreases in commodity prices will reduce the PV 10 value of our estimated proved undeveloped reserves and future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, delays in the development of reserves could cause us to have to reclassify our proved undeveloped reserves as unproved reserves.

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If commodity prices decrease to a level such that our future undiscounted cash flows from our properties are less than their carrying value for a significant period of time, we will be required to take write downs of the carrying values of our properties.

Accounting rules require that we periodically review the carrying value of our properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our properties. A writedown constitutes a non cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations for the periods in which such charges are taken.

Unless we replace our reserves with new reserves and develop those reserves, our reserves and production will decline, which would adversely affect our future cash flows and results of operations.

Producing natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Unless we conduct successful ongoing exploitation, development and exploration activities or continually acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Our future natural gas reserves and production, and therefore our future cash flow and results of operations, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire sufficient additional reserves to replace our current and future production. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations would be adversely affected.

Conservation measures and technological advances could reduce demand for oil and natural gas.

Fuel conservation measures, alternative fuel requirements, increasing consumer demand for alternatives to oil and natural gas, technological advances in fuel economy and energy generation devices could reduce demand for oil and natural gas. The impact of the changing demand for oil and gas services and products may have a material adverse effect on our business, financial condition, results of operations and cash flows.

The inability of our significant customers to meet their obligations to us may adversely affect our financial results.

In addition to credit risk related to receivables from commodity derivative contracts, our principal exposures to credit risk are through joint interest receivables ($116 million at December 31, 2014) and the sale of our natural gas production ($192 million in receivables at December 31, 2014), which we market to energy marketing companies, end users, and refineries. Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leased properties on which we wish to drill. We can do very little to choose who participates in our wells. We are also subject to credit risk due to concentration of our natural gas receivables with several significant customers. The largest purchaser of our natural gas during the twelve months ended December 31, 2014 purchased approximately 29% of our operated production. We do not require our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Our operations may be exposed to significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to our business activities.

We may incur significant delays, costs and liabilities as a result of environmental and occupational health and safety requirements applicable to our exploration, development and production activities. These delays, costs and liabilities could arise under a wide range of federal, regional, state and local laws and regulations relating to protection of the environment and worker health and safety, including regulations and enforcement policies that have tended to become increasingly strict over time resulting in longer waiting periods to receive permits and other regulatory approvals. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations.

For example, in June 2013 and January 2014, we received orders for compliance from federal regulatory agencies, including the EPA, relating to certain of our activities in West Virginia. The orders allege that certain of our operations at several well sites are in non compliance with certain environmental regulations, such as unpermitted discharges of fill material into wetlands or waters of the United States that are potentially in violation of the Clean Water Act. We have responded to all pending orders and are actively

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cooperating with the relevant agencies. No fine or penalty relating to these matters has been proposed at this time, but the Company believes that these actions will result in monetary sanctions exceeding $100,000. In addition, we expect to incur additional costs to remediate these well locations in order to bring them into compliance with applicable environmental laws and regulations. We have not, however, been required to suspend our operations at these locations to date and our management team does not expect these matters to have a material adverse effect on our financial condition, results of operations or cash flows.

Strict, joint and several liabilities may be imposed under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. In addition, claims for damages to persons or property, including natural resources, may result from the environmental and worker health and safety impacts of our operations. We have been named from time to time as a defendant in litigation related to such matters. For example, we have been named as the defendant in separate lawsuits in Colorado, West Virginia and Pennsylvania in which the plaintiffs have alleged that our oil and natural gas activities exposed them to hazardous substances and damaged their properties. The plaintiffs have requested unspecified damages and other injunctive or equitable relief. We are not yet able to estimate what our aggregate exposure for monetary or other damages resulting from these or other similar claims might be. Also, new laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. If we were not able to recover the resulting costs through insurance or increased revenues, our business, financial condition or results of operations could be adversely affected.

We may incur substantial losses and be subject to substantial liability claims as a result of our operations. Additionally, we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations.

Our natural gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing natural gas, including the possibility of:

- environmental hazards, such as uncontrollable releases of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater, air and shoreline contamination;
- abnormally pressured formations;
- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;
- fires, explosions and ruptures of pipelines;
- personal injuries and death;
- natural disasters; and
- terrorist attacks targeting natural gas and oil related facilities and infrastructure.

Any of these risks could adversely affect our ability to conduct operations or result in substantial loss to us as a result of claims for:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;
- suspension of our operations; and

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- repair and remediation costs.

We may elect not to obtain insurance for any or all of these risks if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

We may be limited in our ability to choose gathering operators and processing and fractionation services providers in our areas of operations pursuant to our agreements with Antero Midstream.

Pursuant to the gas gathering and compression agreement that we have entered into with Antero Midstream, we have dedicated the gathering and compression of all of our current and future natural gas production in West Virginia, Ohio and Pennsylvania to Antero Midstream, so long as such production is not otherwise subject to a pre existing dedication. Further, pursuant to the right of first offer that we have entered into with Antero Midstream, Antero Midstream has a right to bid to provide certain processing and fractionation services in respect of all of our current and future gas production (as long as it is not subject to a pre existing dedication) and will be entitled to provide such services if its bid matches or is more favorable to us than terms proposed by other parties. As a result, we will be limited in our ability to use other gathering operators in West Virginia, Ohio and Pennsylvania, even if such operators are able to offer us more favorable pricing or more efficient service. We will also be limited in our ability to use other processing and fractionation services providers in any area to the extent Antero Midstream is able to offer a competitive bid.

Properties that we decide to drill may not yield natural gas or oil in commercially viable quantities.

Properties that we decide to drill that do not yield natural gas or oil in commercially viable quantities will adversely affect our results of operations and financial condition. There is no way to predict in advance of drilling and testing whether any particular prospect will yield natural gas or oil in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of micro seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether natural gas or oil will be present or, if present, whether natural gas or oil will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects. Further, our drilling operations may be curtailed, delayed or cancelled as a result of numerous factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or lost circulation in formations;
- equipment failure or accidents;
- adverse weather conditions;
- compliance with environmental and other governmental or contractual requirements; and
- increase in the cost of, shortages or delays in the availability of, electricity, supplies, materials, drilling or workover rigs, equipment and services.

We may be unable to make attractive acquisitions or successfully integrate acquired businesses, and any inability to do so may disrupt our business and hinder our ability to grow.

In the future we may make acquisitions of businesses that complement or expand our current business. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive acquisition opportunities, we may not be able to complete the acquisition or do so on commercially acceptable terms.

The success of any completed acquisition will depend on our ability to integrate effectively the acquired business into our existing operations. The process of integrating acquired businesses may involve unforeseen difficulties and may require a

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disproportionate amount of our managerial and financial resources. In addition, possible future acquisitions may be larger and for purchase prices significantly higher than those paid for earlier acquisitions. No assurance can be given that we will be able to identify additional suitable acquisition opportunities, negotiate acceptable terms, obtain financing for acquisitions on acceptable terms or successfully acquire identified targets. Our failure to achieve consolidation savings, to integrate the acquired businesses and assets into our existing operations successfully or to minimize any unforeseen operational difficulties could have a material adverse effect on our financial condition and results of operations.

In addition, our revolving credit facility and the indentures governing our senior notes impose certain limitations on our ability to enter into mergers or combination transactions. Our revolving credit facility and the indentures governing our senior notes also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses.

Market conditions or operational impediments may hinder our access to natural gas, NGLs, and oil markets or delay our production.

Market conditions or the unavailability of satisfactory natural gas, NGLs, and oil transportation arrangements may hinder our access to natural gas, NGLs, and oil markets or delay our production. The availability of a ready market for our natural gas and oil production depends on a number of factors, including the demand for and supply of natural gas, NGLs, and oil and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines, and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of natural gas, NGLs, and oil pipelines or gathering system capacity. In addition, if natural gas, NGLs, or oil quality specifications for the third party natural gas, NGLs, or oil pipelines with which we connect change so as to restrict our ability to transport natural gas, NGLs, or oil, our access to natural gas, NGLs, and oil markets could be impeded. If our production becomes shut in for any of these or other reasons, we would be unable to realize revenue from those wells until other arrangements were made to deliver the products to market.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations or expose us to significant liabilities.

Our natural gas exploration, production and transportation operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state and local governmental authorities. We may incur substantial costs in order to maintain compliance with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Such costs could have a material adverse effect on our business, financial condition and results of operations.

Our business is subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, and the production and transportation of, natural gas, NGLs, and oil. Failure to comply with such laws and regulations, including any evolving interpretation and enforcement by governmental authorities, could have a material adverse effect on our business, financial condition and results of operations.

Changes to existing or new regulations may unfavorably impact us, could result in increased operating costs and have a material adverse effect on our financial condition and results of operations. Such potential regulations could increase our operating costs, reduce our liquidity, delay or halt our operations or otherwise alter the way we conduct our business, which could in turn have a material adverse effect on our financial condition, results of operations and cash flows.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel, and oilfield services could adversely affect our ability to execute our exploration and development plans within our budget and on a timely basis.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers, and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with natural gas and oil prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. We cannot predict whether these conditions will exist in the future and, if so, what their timing and duration will be. Such shortages could delay or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

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A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by the FERC as a natural gas company under the NGA. Although the FERC has not made any formal determinations with respect to any of our facilities, we believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company. The distinction between FERC regulated transmission services and federally unregulated gathering services, however, has been the subject of substantial litigation, and the FERC determines whether facilities are gathering facilities on a case by case basis, so the classification and regulation of our gathering facilities may be subject to change based on future determinations by FERC, the courts or Congress.

Should we fail to comply with all applicable FERC administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.

Under the EPAct of 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation. While our systems have not been regulated by FERC under the NGA, FERC has adopted regulations that may subject certain of our otherwise non FERC jurisdictional facilities to FERC annual reporting requirements. Additional rules and legislation pertaining to those and other matters may be considered or adopted by FERC from time to time. Failure to comply with those regulations in the future could subject us to civil penalty liability.

Climate change laws and regulations restricting emissions of "greenhouse gases" could result in increased operating costs and reduced demand for the oil and natural gas that we produce while potential physical effects of climate change could disrupt our production and cause us to incur significant costs in preparing for or responding to those effects.

In response to findings that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment, the EPA has adopted regulations under existing provisions of the federal Clean Air Act that, among other things, establish PSD construction and Title V operating permit reviews for certain large stationary sources. 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. Moreover, the Obama Administration is expected to release a series of new regulations on the oil and gas industry in 2015, including federal standards limiting emissions of methane, a GHG. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified sources. In addition, the EPA has adopted rules requiring the monitoring and reporting of GHG emissions from specified onshore and offshore oil and gas production sources in the United States on an annual basis, which include certain of our operations. We are monitoring GHG emissions from our operations in accordance with the GHG emissions reporting rule and believe that our monitoring activities are in substantial compliance with applicable reporting obligations. Recently, the EPA finalized modifications to its GHG reporting rules that would require covered entities to report emissions on an individual GHG basis. In addition, the EPA has proposed a rule that would expand the agency's reporting requirements to cover completions and workovers from hydraulically fractured oil wells. These changes to EPA's GHG emissions reporting rule could result in increased compliance costs.

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. 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 imposing reporting obligations on, or limiting emissions of GHGs from, our equipment and operations could require us to incur costs to reduce emissions of GHGs associated with our operations. Substantial limitations on GHG emissions could also 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 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 operations.

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Federal, state and local legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs and additional operating restrictions or delays in the completion of oil and natural gas wells and adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of 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 regularly use hydraulic fracturing as part of our operations. Hydraulic fracturing typically is regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the federal SDWA over certain hydraulic fracturing activities involving the use of diesel fuels and issued permitting guidance in February 2014 regarding the use of diesel fuels in fracturing fluids. In May 2012, 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. Furthermore, the EPA has adopted regulations requiring the reduction of volatile organic compound emissions from oil and natural gas production facilities by mandating the use of "green completions" for hydraulic fracturing activities. These regulations require the operator to recover rather than vent gas and natural gas liquids that return to the surface during well completion operations. 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, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and 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 fracturing activities in particular. Some states and municipalities have sought to ban hydraulic fracturing altogether. 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, 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 draft 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 sometime in the first half of 2015. 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 sometime in the first half of 2015. In addition, the U.S. Department of the Interior published a revised proposed rule in May 2013 that would implement updated requirements for hydraulic fracturing activities on federal lands, including new requirements relating to public disclosure, well bore integrity and handling of flowback water. Other governmental agencies, including the U.S. Department of Energy, have evaluated or are evaluating various other aspects of hydraulic fracturing. These activities could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanisms, and could ultimately make it more difficult or costly for us to perform hydraulic fracturing activities and increase our costs of compliance and doing business.

Competition in the natural gas industry is intense, making it more difficult for us to acquire properties, market natural gas and secure trained personnel.

Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment for acquiring properties, marketing natural gas and securing trained personnel. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours. Those companies may be able to pay more for productive natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, other companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past three years due to competition and may increase substantially in the future. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital, which could have a material adverse effect on our business.

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Terrorist or cyber attacks and threats could have a material adverse effect on our business, financial condition or results of operations.

Terrorist or cyber attacks may significantly affect the energy industry, including our operations and those of our customers, as well as general economic conditions, consumer confidence and spending and market liquidity. Strategic targets, such as energy related assets, may be at greater risk of future attacks than other targets in the United States. Our insurance may not protect us against such occurrences. Consequently, it is possible that any of these occurrences, or a combination of them, could have a material adverse effect on our business, financial condition and results of operations.

The loss of senior management or technical personnel could adversely affect operations.

We depend on the services of our senior management and technical personnel. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals. The loss of the services of our senior management or technical personnel, including Paul M. Rady, our Chairman and Chief Executive Officer, and Glen C. Warren, Jr., our President and Chief Financial Officer, could have a material adverse effect on our business, financial condition and results of operations.

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

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

Increases in interest rates could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms of and cost of capital, increases in interest rates or a reduction in credit rating. These changes could cause our cost of doing business to increase, limit our ability to pursue acquisition opportunities, reduce cash flow used for drilling and place us at a competitive disadvantage. For example, during 2014, we had estimated average outstanding borrowings under our revolving credit facility of approximately $1.083 billion, and the impact of a 1.0% increase in interest rates on this amount of indebtedness would result in increased interest expense for that period of approximately $11 million and a corresponding decrease in our net income before the effects of income taxes. Recent and continuing disruptions and volatility in the global financial markets may lead to a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in cash flows from operations or the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

We may be subject to risks in connection with acquisitions of properties.

The successful acquisition of producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future natural gas prices and their applicable differentials;
- operating costs; and
- potential environmental and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. Inspections may not always be performed on every well, and environmental problems, such as groundwater contamination, are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the seller may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an "as is" basis.

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Certain federal income tax deductions currently available with respect to natural gas and oil exploration and development may be eliminated, and additional state taxes on natural gas extraction may be imposed, as a result of future legislation.

The Fiscal Year 2016 Budget proposed by the President of the United States recommends the elimination of certain key U.S. federal income tax incentives currently available to oil and gas exploration and production companies, and legislation has been introduced in Congress that would implement many of these proposals. Such 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 certain U.S. production activities for oil and gas production; and (iv) an extension of the amortization period for certain geological and geophysical expenditures. It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective.

The passage of this legislation or any other similar change in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available with respect to natural gas and oil exploration and development, and any such change could negatively affect our financial condition and results of operations.

In May 2014, the Ohio State House passed House Bill 375, which introduced a severance tax on production from horizontally fractured wells at a rate of 2.5 percent of wellhead gross receipts. The Ohio State Senate has yet to consider this proposal. It is unclear whether this or any similar Ohio legislation will be enacted or when such legislation could be made effective.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 3. Legal Proceedings

In March 2011, we received orders for compliance from federal regulatory agencies, including the EPA, relating to certain of our activities in West Virginia. The orders allege that certain of our operations at several well sites are in non compliance with certain environmental regulations, such as unpermitted discharges of fill material into wetlands or waters of the United States that are potentially in violation of the Clean Water Act. No fine or penalty relating to these matters has been proposed at this time, but the Company believes that these actions will result in monetary sanctions exceeding $100,000. We are unable to estimate the total amount of such monetary sanctions or costs to remediate these locations in order to bring them into compliance with applicable environmental laws and regulations. We have not, however, been required to suspend our operations at these locations to date and management does not expect these matters to have a material adverse effect on our financial condition, results of operations or cash flows.

We have been named in separate lawsuits in Colorado, West Virginia, Ohio, and Pennsylvania in which the plaintiffs have alleged that our oil and natural gas activities exposed them to hazardous substances and damaged their properties and their persons. The plaintiffs have requested unspecified damages and other injunctive or equitable relief. We deny as such allegations and intend to vigorously defend ourselves against these actions. We are unable to estimate the amount of monetary damages, if any, that might result from these claims.

We are party to various other legal proceedings and claims in the ordinary course of our business. We believe certain of these matters will be covered by insurance and that the outcome of other matters will not have a material adverse effect on our consolidated financial position, results of operations or liquidity.

Item 4. Mine Safety Disclosures

Not applicable.

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PART II

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

Common Stock

We have one class of common shares outstanding, our par value $0.01 per share common stock. Our common stock is traded on the New York Stock Exchange under the symbol "AR". On February 19, 2015, our common stock was held by 3 holders of record. The number of holders does not include the shareholders for whom shares are held in a "nominee" or "street" name.

The table below reflects the high and low intraday sales prices per share of the Common Stock on the New York Stock Exchange for each period presented.

	Common Stock	
	High	Low
2014:		
Quarter ended December 31, 2014	$ 56.81	$ 37.85
Quarter ended September 30, 2014	$ 66.10	$ 53.42
Quarter ended June 30, 2014	$ 67.92	$ 56.28
Quarter ended March 31, 2014	$ 68.43	$ 53.61
2013:		
For the period from October 10, 2013 through December 31, 2013	$ 63.57	$ 51.56

Prior to our IPO on October 10, 2013, there was no public market for our Common Stock.

Issuer Purchases of Equity Securities

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

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans	Maximum Number of Shares that May Yet be Purchased Under the Plan
October 1, 2014 - October 31, 2014	2,060	$ 51.99	—	N/A
November 1, 2014 - November 30, 2014	255	$ 52.03	—	N/A
December 1, 2014 - December 31, 2014	671	$ 41.85	—	N/A

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

Dividend Restrictions

Our ability to pay dividends is governed by (i) the provisions of Delaware corporation law, (ii) our Certificate of Incorporation and Bylaws, (iii) indentures related to our 6.00% senior notes due 2020, 5.375% senior notes due 2021, and 5.125% senior notes due 2022, and (iv) our revolving credit facility. We have not paid or declared any dividends on our Common Stock. The future payment of cash dividends on our Common Stock, if any, is within the discretion of the Board of Directors and will depend on our earnings, capital requirements, financial condition, and other relevant factors. There is no assurance that we will pay any cash dividends on our Common Stock. We do not anticipate declaring or paying any cash dividends to holders of our Common Stock in the foreseeable future.

Stock Performance Graph

The graph below shows the cumulative total shareholder return assuming the investment of $100 on October 10, 2013 in each of Antero Common Stock, the S&P 500 Index, and the Dow Jones U.S. Exploration and Production Index. We believe the Dow Jones

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U.S. Exploration and Production Index is meaningful because it is an independent, objective view of the performance of similarly sized energy companies.

Comparison of Cumulative Total Returns Among Antero Resources Corporation, the S&P 500

Index, and the Dow Jones US Exploration and Production Index

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Item 6. Selected Financial Data

The following table shows our selected historical consolidated financial data, for the periods ended and as of the dates indicated, for Antero Resources Corporation and its subsidiaries.

The selected statement of operations data for the years ended December 31, 2012, 2013, and 2014 and the balance sheet data as of December 31, 2013 and 2014 are derived from our audited consolidated financial statements included in Item 8 of this Annual Report on Form 10 K. The selected statement of operations data for the years ended December 31, 2009 and 2010 and the balance sheet data as of December 31, 2010, 2011, and 2012 are derived from our audited consolidated financial statements not included in Item 8 of this Annual Report on Form 10 K.

The statement of operations data for all periods presented has been recast to present the results of operations from our Piceance Basin and Arkoma Basin operations in discontinued operations. The losses on the sales of these properties are also included in discontinued operations in 2012, with adjustments in 2013 and 2014 due to the resolution of certain liabilities recorded at the time of the sales and the settlement of final purchase price adjustments. The results from continuing operations reflect our remaining operations in the Appalachian Basin. No part of our general and administrative expenses or interest expense was allocated to discontinued operations.

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The selected financial data presented below are qualified in their entirety by reference to, and should be read in conjunction with, "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and related notes included elsewhere in this report.

	Year ended Dec 31,				
(in thousands, except per share amounts)	2010	2011	2012	2013	2014
Statement of operations data:					
Operating revenues:					
Natural gas sales	$ 47,392	195,116	259,743	689,198	1,301,349
NGLs sales	—	—	3,719	111,663	328,323
Oil sales	39	173	1,520	20,584	107,080
Gathering, compression, and water distribution	—	—	—	—	22,075
Marketing	—	—	—	—	53,604
Commodity derivative fair value gains	77,599	496,064	179,546	491,689	868,201
Gain on sale of assets	—	—	291,190	—	40,000
Total operating revenues	125,030	691,353	735,718	1,313,134	2,720,632
Operating expenses:					
Lease operating	$ 1,158	4,608	6,243	9,439	29,341
Gathering, compression, processing, and transportation	9,237	37,315	91,094	218,428	461,413
Production and ad valorem taxes	2,885	11,915	20,210	50,481	87,918
Marketing	—	—	—	—	103,435
Exploration	2,350	4,034	14,675	22,272	27,893
Impairment of unproved properties	6,076	4,664	12,070	10,928	15,198
Depletion, depreciation, and amortization	18,522	55,716	102,026	233,876	477,896
Accretion of asset retirement obligations	11	76	101	1,065	1,271
General and administrative (including $365,280 and $112,252 of equity-based compensation expense in 2013 and 2014, respectively)	24,496	33,342	45,284	425,438	216,533
Loss on sale of compressor station	—	8,700	—	—	—
Total operating expenses	64,735	160,370	291,703	971,927	1,420,898
Operating income	60,295	530,983	444,015	341,207	1,299,734
Other Expenses:					
Interest expense	$ (56,463)	(74,404)	(97,510)	(136,617)	(160,051)
Loss on early extinguishment of debt	—	—	—	(42,567)	(20,386)
Interest rate derivative fair value losses	(2,677)	(94)	—	—	—
Total other expenses	(59,140)	(74,498)	(97,510)	(179,184)	(180,437)
Income before income taxes and discontinued operations	1,155	456,485	346,505	162,023	1,119,297
Income tax expense	$ (939)	(185,297)	(121,229)	(186,210)	(445,672)
Income (loss) from continuing operations	216	271,188	225,276	(24,187)	673,625
Discontinued operations:					
Income (loss) from results of operations and sale of discontinued operations, net of income tax	228,412	121,490	(510,345)	5,257	2,210
	228,628	392,678	(285,069)	(18,930)	675,835

Net income (loss) and comprehensive income (loss) including noncontrolling interest					
Net income and comprehensive income attributable to noncontrolling interest	—	—	—	—	2,248
Net income (loss) attributable to Antero Resources Corporation	$ 228,628	392,678	(285,069)	(18,930)	673,587
Earnings (loss) per share:					
Continuing operations(1)	$ —	1.04	0.86	(0.09)	2.56
Discontinued operations(1)	$ 0.87	0.46	(1.95)	0.02	0.01
Total	$ 0.87	1.50	(1.09)	(0.07)	2.57
Earnings (loss) per share—assuming dilution:					
Continuing operations(1)	$ —	1.04	0.86	(0.09)	2.56
Discontinued operations(1)	$ 0.87	0.46	(1.95)	0.02	0.01
	$ 0.87	1.50	(1.09)	(0.07)	2.57

(1) Earnings (loss) from continuing operations per common share from and earnings (loss) from continuing operations per common share—assuming dilution for each of the years in the four year period ended December 31, 2013 were calculated as if the shares issued in the Corporate Reorganization and IPO described in Note 1 were outstanding for the entire period. Earnings (loss) from continuing operations per common share and earnings (loss) from continuing operations per common share—assuming dilution were less than $0.01 per share for the year ended December 31, 2010.

(in thousands)	Year ended Dec 31, 2010	2011	2012	2013	2014
Balance sheet data (at period end):					
Cash and cash equivalents	$ 8,988	3,343	18,989	17,487	245,979
Other current assets	147,917	330,299	255,617	316,077	1,006,181
Total current assets	156,905	333,642	274,606	333,564	1,252,160
Natural gas properties, at cost (successful efforts method):					
Unproved properties	737,358	834,255	1,243,237	1,513,136	2,060,936
Producing properties	1,762,206	2,497,306	1,682,297	3,621,672	6,515,221
Fresh water distribution systems	—	—	6,835	231,684	421,012
Gathering systems and facilities	85,404	142,241	168,930	584,626	1,197,239
Other property and equipment	5,975	8,314	9,517	15,757	37,687
	2,590,943	3,482,116	3,110,816	5,966,875	10,232,095
Less accumulated depletion, depreciation, and amortization	(431,181)	(601,702)	(173,343)	(407,219)	(879,643)
Property and equipment, net	2,159,762	2,880,414	2,937,473	5,559,656	9,352,452
Other assets	169,620	574,744	406,714	720,361	968,883
Total assets	$ 2,486,287	3,788,800	3,618,793	6,613,581	11,573,495
Current liabilities	$ 152,483	255,058	376,296	622,229	1,155,105
Long-term indebtedness	652,632	1,317,330	1,444,058	2,078,999	4,362,550
Other long-term liabilities	86,185	257,606	124,702	313,693	582,010
Total equity	1,594,987	1,958,806	1,673,737	3,598,660	5,473,830
Total liabilities and equity	$ 2,486,287	3,788,800	3,618,793	6,613,581	11,573,495
Other financial data:					
Adjusted EBITDAX from continuing operations	$ 27,824	160,259	284,710	649,358	1,161,767
Adjusted EBITDAX from discontinued operations	$ 169,854	180,562	149,605	—	—
Total EBITDAX	$ 197,678	340,821	434,315	649,358	1,161,767
Net cash provided by operating activities	$ 127,791	266,307	332,255	534,707	998,121
Net cash used in investing activities	$ (230,672)	(901,249)	(463,491)	(2,673,592)	(4,089,650)
Net cash provided by financing activities	$ 101,200	629,297	146,882	2,137,383	3,320,021
Capital expenditures	$ 390,974	903,422	1,682,549	2,671,573	4,086,568

"Adjusted EBITDAX" is a non-GAAP financial measure that we define as net income (loss) before interest expense, interest income, derivative fair value gains or losses (excluding net cash receipts or payments on derivative instruments included in derivative fair value gains or losses), taxes, impairments, depletion, depreciation, amortization, exploration expense, franchise taxes, equity-based compensation, loss on early extinguishment of debt, and gain or loss on sale of assets. "Adjusted EBITDAX," as used and defined by us, may not be comparable to similarly titled measures employed by other companies and is not a measure of performance calculated in accordance with GAAP. Adjusted EBITDAX should not be considered in isolation or as a substitute for operating income, net income or loss, cash flows provided by operating, investing, and financing activities, or other income or cash flow statement data prepared in accordance with GAAP. Adjusted EBITDAX provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, and working capital movement or tax position. Adjusted EBITDAX does not represent funds available for discretionary use because those funds may be required for debt service, capital expenditures, working capital, income taxes, franchise taxes, exploration expenses, and other commitments and obligations. However, our management team believes Adjusted EBITDAX is useful to an investor in evaluating our financial performance because this measure:

- is widely used by investors in the oil and natural gas industry to measure a company's operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired, among other factors;
- helps investors to more meaningfully evaluate and compare the results of our operations from period to period by removing the effect of our capital structure from our operating structure; and
- is used by our management team for various purposes, including as a measure of operating performance, in presentations to our board of directors, as a basis for strategic planning and forecasting and by our lenders pursuant to covenants under our revolving credit facility and the indentures governing our senior notes.

There are significant limitations to using Adjusted EBITDAX as a measure of performance, including the inability to analyze the effect of certain recurring and non recurring items that materially affect our net income or loss, the lack of comparability of results of operations of different companies and the different methods of calculating Adjusted EBITDAX reported by different companies. The following table represents a reconciliation of our net income (loss) from continuing operations to Adjusted EBITDAX from continuing operations, a reconciliation of our net income (loss) from discontinued operations to Adjusted EBITDAX from

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discontinued operations, and a reconciliation of our total Adjusted EBITDAX to net cash provided by operating activities per our consolidated statements of cash flows, in each case for the periods presented:

	Year ended December 31,				
(in thousands)	2010	2011	2012	2013	2014
Net income (loss) from continuing operations	$ 216	271,188	225,276	(24,187)	673,625
Commodity derivative fair value gains(1)	(77,599)	(496,064)	(179,546)	(491,689)	(868,201)
Net cash receipts on settled derivative instruments(1)	15,063	49,944	178,491	163,570	135,784
(Gain) loss on sale of assets	—	8,700	(291,190)	—	(40,000)
Interest expense	59,140	74,498	97,510	136,617	160,051
Loss on early extinguishment of debt	—	—	—	42,567	20,386
Income tax expense	939	185,297	121,229	186,210	445,672
Depreciation, depletion, amortization, and accretion	18,533	55,792	102,127	234,941	479,167
Impairment of unproved properties	6,076	4,664	12,070	10,928	15,198
Exploration expense	2,350	4,034	14,675	22,272	27,893
Equity-based compensation expense	—	—	—	365,280	112,252
State franchise taxes and other	3,106	2,206	4,068	2,849	2,188
Less net income attributable to noncontrolling interest	—	—	—	—	2,248
Adjusted EBITDAX from continuing operations	27,824	160,259	284,710	649,358	1,161,767
Net income (loss) from discontinued operations	228,412	121,490	(510,345)	5,257	2,210
Commodity derivative fair value gains	(166,685)	(180,130)	(46,358)	—	—
Net cash receipts on settled derivative instruments	58,650	66,654	92,166	—	—
Loss (gain) on sale of assets	(147,559)	—	795,945	(8,506)	(3,564)
Income tax expense (benefit)	29,070	45,155	(272,553)	3,249	1,354
Depreciation, depletion, amortization, and accretion	115,739	115,164	89,124	—	—
Impairment of unproved properties	29,783	6,387	962	—	—
Exploration expense	22,444	5,842	664	—	—
Adjusted EBITDAX from discontinued operations	169,854	180,562	149,605	—	—
Total adjusted EBITDAX	197,678	340,821	434,315	649,358	1,161,767
Interest expense	(59,140)	(74,498)	(97,510)	(136,617)	(160,051)
Exploration expense	(24,794)	(9,876)	(15,339)	(22,272)	(27,893)
Changes in current assets and liabilities	(698)	8,309	9,887	41,914	17,805
Net income attributable to noncontrolling interest	—	—	—	—	2,248
State franchise taxes	(3,106)	(2,206)	(4,068)	(2,849)	(2,188)
Other noncash items	17,851	3,757	4,970	5,173	6,433

Net cash provided by operating activities	$ 127,791	266,307	332,255	534,707	998,121

(1) The adjustments for the derivative fair value (gains) losses and net cash received on settled commodity derivative instruments have the effect of adjusting net income (loss) from operations for changes in the fair value of unsettled derivative instruments, which are recognized at the end of each accounting period. As a result, commodity derivate gains and losses are reflected on a cash basis in the calculation of Adjusted EBITDAX for derivatives which settled during the period.

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

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our consolidated financial statements and related notes included elsewhere in this report. The following discussion contains "forward looking statements" that reflect our future plans, estimates, beliefs and expected performance. We caution that assumptions, expectations, projections, intentions, or beliefs about future events may, and often do, vary from actual results and the differences can be material. Some of the key factors that could cause actual results to vary from our expectations include changes in natural gas, NGLs and oil prices, the timing of planned capital expenditures, our ability to fund our development programs, availability of acquisitions, uncertainties in estimating proved reserves and forecasting production results, operational factors affecting the commencement or maintenance of producing wells, the condition of the capital markets generally, as well as our ability to access them, and uncertainties regarding environmental regulations or litigation and other legal or regulatory developments affecting our business, as well as those factors discussed below, all of which are difficult to predict. In light of these risks, uncertainties and assumptions, the forward looking events discussed may not occur. See "Cautionary Statement Regarding Forward Looking Statements." Also, see the risk factors and other cautionary statements described under the heading "Item 1A. Risk Factors." We do not undertake any obligation to publicly update any forward looking statements except as otherwise required by applicable law.

In this section, references to "Antero," "Antero Resources," "we," "us," and "our" refer to Antero Resources Corporation and i subsidiaries, unless otherwise indicated or the context otherwise requires.

Our Company

Antero Resources Corporation is an independent oil and natural gas company engaged in the exploitation, development and acquisition of natural gas, NGLs, and oil properties located in the Appalachian Basin. We focus on unconventional reservoirs, which can generally be characterized as fractured shale formations. Our management team has worked together for many years and has a successful track record of reserve and production growth as well as significant expertise in unconventional resource plays. Our strategy is to leverage our team's experience delineating and developing natural gas resource plays to profitably grow our reserves and production, primarily on our existing multi-year project inventory.

We have assembled a portfolio of long-lived properties that are characterized by what we believe to be low geologic risk and repeatability. Our drilling opportunities are focused in the Marcellus Shale and Utica Shale of the Appalachian Basin. As of December 31, 2014, we held approximately 395,000 net acres in the southwestern core of the Marcellus Shale and approximately 148,000 net acres in the core of the Utica Shale. In addition, we estimate that approximately 191,000 net acres of our Marcellus Shale leasehold are prospective for the slightly shallower Upper Devonian Shale. Finally, we own the deep rights on approximately 171,000 net acres of our Marcellus Shale acreage that we believe is prospective for the dry gas Utica Shale.

As of December 31, 2014, our estimated proved reserves were approximately 12.7 Tcfe, consisting of 10.5 Tcf of natural gas, 330 MMBbl of NGLs, and 28 MMBbl of oil. This represents a 66% increase from proved reserve volumes at December 31, 2013. These reserve estimates have been prepared by our internal reserve engineers and management and audited by our independent reserve engineers. As of December 31, 2014, we had approximately 5,331 potential horizontal well locations on our existing leasehold acreage, both proven and unproven.

We believe we have secured sufficient long-term firm takeaway capacity on major pipelines that are operating or are currently under construction in each of our core operating areas to accommodate our current development plans.

We operate in the following industry segments: (i) the exploration, development and production of natural gas, NGLs, and oil, (ii) gathering and compression, (iii) fresh water distribution, and (iv) marketing of excess firm transportation capacity. All of our operations are conducted in the United States.

Energy Industry Environment

Recently, global energy commodity prices have declined precipitously as a result of several factors including increased worldwide supplies, a stronger U.S. dollar, relatively mild weather in the U.S., and strong competition among oil producing countries for market share. Specifically, prices for WTI have declined from approximately $106.00 per Bbl in June 2014 to less than $50.00 per Bbl in January 2015. Henry Hub natural gas has traded around $3.00 per MMBtu in January 2015 compared to prices a year ago in January 2014 of around $4.40 per MMBtu. In response to these market conditions and concerns about access to capital markets, U.S. exploration and development companies have significantly reduced capital spending plans. Our capital budget for 2015 is $1.8 billion (not including the capital budget of Antero Midstream Partners LP), a 41% reduction from our final 2014 capital budget. We plan to operate an average of 14 drilling rigs in 2015 down from 21 at December 31, 2014 and to complete 130 horizontal Marcellus and Utica wells in 2015, down from 177 in 2014. We believe that our 2015 capital budget will be fully funded through operating cash flow and available borrowing capacity under our revolving credit facility. We will continue to monitor commodity prices and may revise the capital budget if conditions warrant.

Source of Our Revenues

Our revenues are primarily derived from the sale of natural gas and oil production, as well as the sale of NGLs that are extracted from our natural gas during processing. Our production revenues derive entirely from the continental United States. During 2014 our revenues from production were comprised of approximately 75% from the sale of natural gas and 25% from the sale of NGLs and oil. Natural gas, NGLs, and oil prices are inherently volatile and are influenced by many factors outside of our control. All of our production is derived from natural gas wells, some of which also produce NGLs, after processing, and limited quantities of oil. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we use derivative instruments to hedge future sales prices on a significant portion of our production. We currently use fixed-price natural gas, propane, and oil swaps in which we receive a fixed price for future production in exchange for a payment of the variable market price received at the time future production is sold. At the end of each period, we estimate the fair value of these swaps and, because we have not elected hedge accounting, we recognize the changes in the fair value of commodity derivative instruments in earnings at the end of each accounting period. We expect continued volatility in the prices we receive for our production and the fair value of our swaps.

Principal Components of Our Cost Structure

- Lease operating expenses. These are the day to day operating costs incurred to maintain production of our natural gas, NGLs, and oil. Such costs include labor-related costs to monitor producing wells, produced water recycling, monitoring, pumping, maintenance, repairs, and workover expenses. Cost levels for these expenses can vary based on supply and demand for oilfield services.
- Gathering, compression, processing and transportation. These are costs incurred to bring natural gas, NGLs, and oil to the market. Such costs include the costs to operate and maintain our low- and high-pressure gathering and compression systems as well as fees paid to third parties who operate low and high pressure gathering systems that transport our gas. They also include costs to process and extract NGLs from our produced gas and to transport our NGLs and oil to market. We often enter into fixed price long term contracts that secure transportation and processing capacity which may include minimum volume commitments, the cost for which is included in these expenses to the extent that they are not excess capacity.
- Production and ad valorem taxes. Production and ad valorem taxes consist of severance and ad valorem taxes. Severance taxes are paid on produced natural gas, NGLs, and oil based on a percentage of realized prices (not hedged prices) and at fixed per unit rates established by federal, state or local taxing authorities. Ad valorem taxes are paid based on the value of our property and equipment in service.
- Marketing expenses. In 2014, we began to purchase and sell third-party natural gas and ethane, and market our excess firm transportation capacity, in order to utilize our excess firm transportation capacity. Marketing costs include firm transportation costs related to capacity contracted for in advance of having sufficient production and infrastructure to fully utilize the capacity and the costs of third-party purchased gas and ethane. We enter into long-term firm transportation agreements for a significant part of our current and expected future production in order to secure guaranteed capacity on major pipelines.
- Exploration expense. These are geological and geophysical costs and include seismic costs, costs of unsuccessful exploratory dry holes and costs related to unsuccessful leasing efforts.
- Impairment of unproved and proved properties. These costs include unproved property impairment and costs associated with lease expirations. We would also record impairment charges for proved properties if the carrying

value were to exceed estimated future cash flows. Through December 31, 2014, we have not recorded any impairment for proved properties.

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- Depletion, depreciation, and amortization. Depletion, depreciation, and amortization, or DD&A, includes the systematic expensing of the capitalized costs incurred to acquire, explore and develop natural gas, NGLs, and oil. As a “successful efforts” company, we capitalize all costs associated with our acquisition and development efforts and all successful exploration efforts, and allocate these costs to each unit of production using the units of production method.
- General and administrative expense. These costs include overhead, including payroll and benefits for our corporate staff, costs of maintaining our headquarters, costs of managing our production and development operations, franchise taxes, audit and other professional fees, and legal compliance expenses. General and administrative expense also includes noncash equity-based compensation expense. See note 1 to the consolidated financial statements included elsewhere in this report.
- Interest expense. We finance a portion of our working capital requirements and acquisitions with borrowings under our revolving credit facility, which has a variable rate of interest based on LIBOR or the prime rate. As a result, we incur substantial interest expense that is affected by both fluctuations in interest rates and our financing decisions. At December 31, 2014 we had a fixed interest rate of 6.00% on our senior notes due 2020 having a principal balance of $525 million, a fixed interest rate of 5.375% on our senior notes due 2021 having a principal balance of $1 billion, and a fixed interest rate of 5.125% on our senior notes due 2022 having a principal balance of $1.1 billion. We expect to continue to incur significant interest expense as we continue to grow.
- Income tax expense. We are subject to state and federal income taxes but are currently not in a tax paying position for regular federal income taxes, primarily due to the current deductibility of intangible drilling costs and the deferral of unsettled commodity hedge gains for tax purposes until they are settled in an exchange of cash. We do pay some state income or franchise taxes where state income or franchise taxes are determined on a basis other than income. We have recorded deferred income tax expense to the extent our deferred tax liabilities exceed our deferred tax assets. Our deferred tax assets and liabilities result from temporary differences between tax and financial statement income primarily from derivatives, oil and gas properties, and net operating loss carryforwards. We have generated net operating loss carryforwards that expire at various dates from 2024 through 2034. We recorded valuation allowances for deferred tax assets at December 31, 2014 of approximately $27 million primarily for state loss carryforwards for which we do not believe we will realize a benefit. The amount of deferred tax assets considered realizable, however, could change in the near term as we generate taxable income or estimates of future taxable income are reduced.

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Results of Operations

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

The Company has four operating segments: (1) exploration and production, (2) gathering and compression, (3) fresh water distribution, and (4) marketing. Revenues from the gathering and compression and fresh water distribution operations are primarily derived from intersegment transactions for services provided to our exploration and production operations. Marketing revenues are primarily derived from activities to purchase and sell third-party natural gas and to market excess firm transportation capacity to third parties. Marketing of excess firm transportation capacity began in the second quarter of 2014, and was subsequently determined to be a new reportable segment. Prior to 2013, the Company's gathering and compression and fresh water distribution operations were immaterial and were considered ancillary to the Company's exploration and production activities. The operating results and assets of the Company's reportable segments were as follows for the years ended December 31, 2013 and 2014

Following is an analysis of operating income for the various segments for the years ended December 31, 2013 and 2014:

	Exploration and production	Gathering and compression	Fresh water distribution	Elimination of intersegment transactions	Consolidated total
2013:					
Sales and revenues:					
Third-party	$ 1,313,134	—	—	—	1,313,134
Intersegment	—	22,363	35,871	(58,234)	—
	$ 1,313,134	22,363	35,871	(58,234)	1,313,134
Operating expenses:					
Lease operating	$ 9,439	—	3,843	(3,843)	9,439
Gathering, compression, processing, and transportation	238,712	2,079	—	(22,363)	218,428
Depletion, depreciation, and amortization	219,757	11,346	2,773	—	233,876
General and administrative expense (before equity-based compensation)	50,442	7,193	2,523	—	60,158
Equity-based compensation expense	340,931	15,931	8,418	—	365,280
Other operating expenses	82,787	—	1,959	—	84,746
Total	942,068	36,549	19,516	(26,206)	971,927
Operating income (loss)	$ 371,066	(14,186)	16,355	(32,028)	341,207

	Exploration and production	Gathering and compression	Fresh water distribution	Marketing	Elimination of intersegment transactions	Consolidated total
2014:						
Sales and revenues:						
Third-party	$ 2,644,953	6,810	15,265	53,604	—	2,720,632
Intersegment	195	88,936	156,660	—	(245,791)	—
	$ 2,645,148	95,746	171,925	53,604	(245,791)	2,720,632
Operating expenses:						
Lease operating	$ 28,041	—	34,737	—	(33,437)	29,341
Gathering, compression, processing, and transportation	536,879	13,497	—	—	(88,963)	461,413
Depletion, depreciation, and amortization	424,684	36,972	16,240	—	—	477,896
General and administrative expense (before equity-based compensation)	85,701	13,416	5,332	—	(168)	104,281
Equity-based compensation expense	100,634	8,619	2,999	—	—	112,252
Other operating expenses	128,419	1,973	1,888	103,435	—	235,715
Total	1,304,358	74,477	61,196	103,435	(122,568)	1,420,898
Operating income (loss)	$ 1,340,790	21,269	110,729	(49,831)	(123,223)	1,299,734

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The following tables set forth selected operating data for the year ended December 31, 2013 compared to the year ended December 31, 2014:

(in thousands, except per unit and production data)	Year ended December 31, 2013	2014	Amount of Increase (Decrease)	Percent Change
Operating revenues:				
Natural gas sales	$ 689,198	$ 1,301,349	$ 612,151	89 %
NGLs sales	111,663	328,323	216,660	194 %
Oil sales	20,584	107,080	86,496	420 %
Gathering, compression, and water distribution	—	22,075	22,075	*
Marketing	—	53,604	53,604	*
Commodity derivative fair value gains	491,689	868,201	376,512	77 %
Gain on sale of gathering system	—	40,000	40,000	*
Total operating revenues	1,313,134	2,720,632	1,407,498	107 %
Operating expenses:				
Lease operating	9,439	29,341	19,902	211 %
Gathering, compression, processing, and transportation	218,428	461,413	242,985	111 %
Production and ad valorem taxes	50,481	87,918	37,437	74 %
Marketing	—	103,435	103,435	*
Exploration	22,272	27,893	5,621	25 %
Impairment of unproved properties	10,928	15,198	4,270	39 %
Depletion, depreciation, and amortization	233,876	477,896	244,020	104 %
Accretion of asset retirement obligations	1,065	1,271	206	19 %
General and administrative (before equity-based compensation)	60,158	104,281	44,123	73 %
Equity-based compensation	365,280	112,252	(253,028)	(69) %
Total operating expenses	971,927	1,420,898	448,971	46 %
Operating income	341,207	1,299,734	958,527	281 %
Other Expenses:				
Interest expense	(136,617)	(160,051)	(23,434)	17 %
Loss on early extinguishment of debt	(42,567)	(20,386)	22,181	(52) %
Total other expenses	(179,184)	(180,437)	(1,253)	1 %
Income from continuing operations before income taxes and discontinued operations	162,023	1,119,297	957,274	591 %
Income tax expense	(186,210)	(445,672)	(259,462)	139 %
Income (loss) from continuing operations	(24,187)	673,625	697,812	*
Income from discontinued operations	5,257	2,210	(3,047)	(58) %
Net income (loss) and comprehensive income (loss) including noncontrolling interest	(18,930)	675,835	694,765	*
Net income and comprehensive income attributable to noncontrolling interest	—	2,248	2,248	*
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ (18,930)	$ 673,587	$ 692,517	*

Adjusted EBITDAX (1)	$ 649,358	$ 1,161,767	$ 512,409	79	%

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(in thousands, except per unit and production data)	Year ended December 31, 2013	2014	Amount of Increase (Decrease)	Percent Change	
Production data:					
Natural gas (Bcf)	177	317	140	80	%
NGLs (MBbl)	2,123	7,102	4,979	235	%
Oil (MBbl)	226	1,311	1,085	482	%
Combined (Bcfe)	191	368	177	93	%
Daily combined production (MMcfe/d)	522	1,007	485	93	%
Average prices before effects of hedges(2):					
Natural gas (per Mcf)	$ 3.90	$ 4.10	$ 0.20	5	%
NGLs (per Bbl)	$ 52.61	$ 46.23	$ (6.38)	(12)	%
Oil (per Bbl)	$ 91.27	$ 81.65	$ (9.62)	(11)	%
Combined (per Mcfe)	$ 4.31	$ 4.73	$ 0.42	10	%
Average realized prices after effects of hedges(2):					
Natural gas (per Mcf)	$ 4.82	$ 4.52	$ (0.30)	(6)	%
NGLs (per Bbl)	$ 52.61	$ 46.23	$ (6.38)	(12)	%
Oil (per Bbl)	$ 99.06	$ 84.66	$ (14.40)	(15)	%
Combined (per Mcfe)	$ 5.17	$ 5.10	$ (0.07)	(1)	%
Average Costs (per Mcfe):					
Lease operating	$ 0.05	$ 0.08	$ 0.03	60	%
Gathering, compression, processing, and transportation	$ 1.15	$ 1.26	$ 0.11	10	%
Production and ad valorem taxes	$ 0.26	$ 0.24	$ (0.02)	(8)	%
Depletion, depreciation, amortization, and accretion	$ 1.23	$ 1.30	$ 0.07	6	%
General and administrative (before equity-based compensation)	$ 0.32	$ 0.28	$ (0.04)	(13)	%

(1) See “Item 6. Selected Financial Data” included elsewhere in this report for a definition of EBITDAX (a non GAAP measure) and a reconciliation of EBITDAX to net income (loss) from continuing operations.

(2) Average sales prices shown in the table reflect both the before and after effects of our cash settled derivatives. Our calculation of such after effects includes gains or losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting because we do not designate or document them as hedges for accounting purposes. Oil and NGLs production was converted at 6 Mcf per Bbl to calculate total Bcfe production and per Mcfe amounts. This ratio is an estimate of the equivalent energy content of the products and does not necessarily reflect their relative economic value.

*Not meaningful or applicable.

Discussion of Consolidated Results for 2014 Compared to 2013

Natural gas, NGLs, and oil sales. Revenues from production of natural gas, NGLs, and oil increased from $821 million for the year ended December 31, 2013 to $1.737 billion for the year ended December 31, 2014, an increase of $915 million, or 111%. Our production increased by 93% over that same period, from 191 Bcfe, or 522 MMcfe per day, for the year ended December 31, 2013 to 368 Bcfe, or 1,007 MMcfe per day, for the year ended December 31,

2014. Net equivalent prices before the effects of realized hedge gains increased from $4.31 per Mcfe for the year ended December 31, 2013 to $4.73 for the year ended December 31, 2014, an increase of 10%. The 10% increase in net equivalent prices for the year ended December 31, 2014 compared to the prior year resulted from an increase in the mix of production of NGLs and oil compared to the prior year as well as increases in the prices of natural gas, which were partially offset by decreases in the prices of NGLs and oil. Increased production volumes accounted for an approximate $762 million increase in year-over year revenues (calculated as the change in year-to-year volumes times the prior year average price), and increases in our equivalent prices accounted for an approximate $153 million increase in year-over-year revenues (calculated as the change in year-to-year average price times current year production volumes). Production increases resulted from an increase in the number of producing wells as a result of our ongoing drilling program. Based on our current drilling and completion plans for 2015 and the increasing size of our production base, we expect the rate of growth in both our production and our product revenues to decline from the rate of growth realized in 2014. Average prices after the effects of cash settled commodity hedges were $5.17 per Mcfe for 2013 compared to $5.10 per Mcfe for 2014.

Commodity derivative fair value gains. To achieve more predictable cash flows, and to reduce our exposure to downward price fluctuations, we enter into derivative contracts using fixed for variable swap contracts when management believes that favorable future sales prices for our natural gas, NGLs, and oil production can be secured. Because we do not designate these derivatives as accounting hedges, they do not receive accounting hedge treatment, and all mark-to-market gains or losses, as well as cash receipts or payments on settled derivative instruments, are recognized in our statements of operations. For the years ended December 31, 2013

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and 2014, our hedges resulted in derivative fair value gains of $492 million and $868 million, respectively. The derivative fair value gains included $164 million and $136 million of cash settlements received on derivatives for the years ended December 31, 2013 and 2014, respectively. Commodity derivative fair value gains or losses will vary based on future commodity prices and have no cash flow impact until the derivative contracts are settled. Derivative asset or liability positions at the end of any accounting period may reverse to the extent natural gas, NGLs, and oil strip prices increase or decrease from their levels at the end of the accounting period, or as gains or losses are realized through settlement. We expect continued volatility in commodity prices and the related fair value of our derivative instruments.

Gathering, compression, and water distribution. Beginning in the fourth quarter of 2013, we began to recognize our midstream gathering, compression, and water distribution operations as reportable segments. Gathering, compression, and water distribution fees of $22 million (net of intercompany eliminations of $246 million) during the year ended December 31, 2014 represent the portion of such fees that are charged to outside working interest owners and other third parties. Such fees were immaterial in the prior year and were netted against gathering expenses.

Gain on sale of gathering system. In 2012, we closed the sale of a portion of our Marcellus Shale gathering system assets in West Virginia along with exclusive rights to gather our gas for a 20 year period within an area of dedication (AOD) to a joint venture owned by Crestwood Midstream Partners and Crestwood Holdings Partners LLC (together "Crestwood"). Under the terms of the contract, we earned additional proceeds of $40 million if certain volume thresholds were met by December 31, 2014. As the volume thresholds were fully met during 2014, we recorded an additional $40 million of gain on the sale of assets in 2014 and a receivable from Crestwood for a like amount.

Lease operating expenses. Lease operating expenses increased from $9.4 million (net of intercompany eliminations of $4 million) for the year ended December 31, 2013 to $29.3 million (net of intercompany eliminations of $33 million) for the year ended December 31, 2014, an increase of 211%. The increase is a result of the increase in the number of producing wells. On a per unit basis, lease operating expenses increased from $0.05 per Mcfe for the year ended December 31, 2013 to $0.08 for the year ended December 31, 2014. Lease operating expenses per unit have increased as a larger proportion of wells have been on production for longer periods of time compared to the prior year. Further, per unit costs have also increased as a larger proportion of our wells produce condensate at the wellhead. Lease operating expenses are expected to continue to slowly increase on a per unit basis as properties mature and production declines on a per well basis.

Gathering, compression, processing, and transportation expense. Gathering, compression, processing, and transportation expense increased from $218 million (net of intercompany eliminations of $22 million) for the year ended December 31, 2013 to $461 million (net of intercompany eliminations of $89 million) for the year ended December 31, 2014. The increase in these expenses is a result of the increase in production, firm transportation commitments, and third-party gathering, compression and processing expenses. On a per-unit basis, total gathering, compression, processing and transportation expenses increased from $1.15 per Mcfe for the year ended December 31, 2013 to $1.26 for the year ended December 31, 2014 as a larger proportion of our gas was processed compared to the prior year.

We have entered into contracts for significant firm transportation volumes in advance of having sufficient production to fully utilize the capacity. Based on current projected 2015 annual production levels, we estimate that we could incur marketing expense pf $100 million to $150 million for unused and un-marketed transportation capacity.

Production and ad valorem tax expense. Total production and ad valorem taxes increased from $50 million for the year ended December 31, 2013 to $88 million for the year ended December 31, 2014, primarily as a result of increased production and a larger midstream asset base subject to ad valorem taxes. Production taxes as a percentage of natural gas, NGLs, and oil revenues before the effects of hedging were 5.1% for the year ended December 31, 2014 compared to 6.1% 2013. Production taxes decreased as a percentage of revenues as production from Ohio increased. Ohio has a lower severance tax rate than West Virginia. Legislative proposals in the State of Ohio to increase severance taxes on production from horizontally drilled wells could increase our future production tax rates if such legislation is enacted.

Exploration expense. Exploration expense of $22 million for the year ended December 31, 2013 increased to expense of $28 million for the year ended December 31, 2014 primarily because of an increase in unsuccessful lease acquisitions due to an increase in lease acquisition efforts.

Impairment of unproved properties. Impairment of unproved properties was approximately $15 million for the year ended December 31, 2014 compared to $11 million in 2013. We charge impairment expense for expired or soon-to-be expired leases when we determine they are impaired based on factors such as remaining lease terms, reservoir performance, commodity price outlooks or

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future plans to develop the acreage, and recognize impairment costs accordingly.

DD&A. DD&A increased from $234 million for the year ended December 31, 2013 to $478 million for the year ended December 31, 2014, primarily because of increased production. DD&A per Mcfe increased by 6%, from $1.23 per Mcfe during the year ended December 31, 2013 to $1.30 per Mcfe during the year ended December 31, 2014, primarily due to increased depreciation on growing midstream assets and facilities.

We evaluate the impairment of our proved natural gas and oil properties on a field-by-field basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we reduce the carrying amount of the oil and gas properties to their estimated fair value. No impairment expenses were recorded for the year ended December 31, 2013 or 2014 for proved properties.

General and administrative and equity-based compensation expense. General and administrative expense (before equity-based compensation expense) increased from $60 million for the year ended December 31, 2013 to $104 million for the year ended December 31, 2014, primarily as a result of increased staffing levels and related salary and benefits expenses, as well as increases in legal and other general corporate expenses, all of which are due to our increase in development activities and production levels. On a per unit basis, general and administrative expense before equity-based compensation decreased by 13%, from $0.32 per Mcfe during the year ended December 31, 2013 to $0.28 per Mcfe during the year ended December 31, 2014 primarily due to a 93% increase in production. We had 233 employees as of December 31, 2013 and 444 employees as of December 31, 2014.

Noncash equity-based compensation expense decreased from $365 million for the year ended December 31, 2013 to $112 million for the year ended December 31, 2014. Noncash equity-based compensation expense included charges of $365 million and $84 million for the years ended December 31, 2013 and 2014, respectively, for the amortization of expense related to the vesting of profits interests issued upon the completion of our IPO in 2013. See note 1 to the consolidated financial statements included elsewhere in this report for more information on the vested profits interest charges.

Interest expense. Interest expense increased from $137 million for the year ended December 31, 2013 to $160 million for the year ended December 31, 2014, primarily due to increased indebtedness. Interest expense includes approximately $6 million and $8 million of non-cash amortization of deferred financing costs for the years ended December 31, 2013 and 2014, respectively.

Income tax expense. Income tax expense increased from $186 million for the year ended December 31, 2013 to $446 million for the year ended December 31, 2014 because of the increase in pre-tax income compared to the prior year. Equity-based compensation expense of $365 million in 2013 and $84 million in 2014 related to the vested profits interests charge is not deductible for federal or state income taxes and, along with the effect of state taxes, largely accounts for the difference between the federal tax rate of 35% and the rates at which income tax expense was provided for the years ended December 31, 2013 and 2014.

At December 31, 2014, we had approximately $1.1 billion of U.S. federal net operating loss carryforwards (NOLs) and approximately $1.0 billion of state NOLs, which expire from 2024 through 2034. From time to time there has been proposed legislation in the U.S. Congress to eliminate or limit future deductions for intangible drilling costs; such legislation could significantly affect our future taxable position if passed. The impact of any change will be recorded in the period that any such legislation might be enacted.

The calculation of our tax liabilities involves uncertainties in the application of complex tax laws and regulations. We give financial statement recognition to those tax positions that we believe are more-likely-than-not to be sustained upon examination by the Internal Revenue Service or state revenue authorities. The financial statements include unrecognized benefits at December 31, 2014 of $11 million that, if recognized, would result in a reduction of current income taxes payable and an increase in noncurrent deferred tax liabilities. As of December 31, 2014, we have accrued approximately $0.8 million of interest on unrecognized tax benefits.

During 2014, the Internal Revenue Service completed its examination of the tax returns of Antero Resources Finance Corporation (which was merged with Antero Resources Corporation in December 2013) for its tax years 2011 and 2012. There were no adjustments to our tax returns as a result of the examination. The Company's state tax returns are being examined by West Virginia taxing authorities for tax years 2010 through 2012. The Company does not expect any material adjustments to tax liabilities will result from the examination.

Income from discontinued operations. In 2012, the Company sold its Piceance Basin assets in Colorado and its Arkoma Basin assets in Oklahoma. Total proceeds from the sales, including liquidation of related hedge positions, were approximately $843 million and pre-tax losses on the asset sales of approximately $796 million were recorded in 2012. Pre-tax losses were adjusted

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downward in 2013 and 2014 by $8.5 million and $3.6 million for the resolution of certain liabilities recorded at the time of the sales and settlement of final contractual purchase price adjustments.

Adjusted EBITDAX. Adjusted EBITDAX increased from $649 million for the year ended December 31, 2013 to $1.162 billion for the year ended December 31, 2014, an increase of 79%. The increase in Adjusted EBITDAX was primarily due to a 93% increase in production, which was partially offset by a 1% decrease in the average per Mcfe price received after the impact of cash settled derivatives, net of the related increases in cash operating and general and administrative expenses. See "Item 6. Selected Financial Data" included elsewhere in this report for a definition of EBITDAX (a non GAAP measure) and a reconciliation of EBITDAX to net income (loss) from continuing operations.

Discussion of Segment Results for 2014 Compared to 2013

Gathering and Compression

Revenue for the gathering and compression segment increased from $22.4 million for the year ended December 31, 2013 to $95.7 million for the year ended December 31, 2014, an increase of $73.3 million, or 327%. Gathering revenues increased by $68.1 million from the prior year and compression revenues increased by $5.2 million as additional wells on production increased throughput volumes. During 2014, we added twelve high-pressure gathering lines, a condensate gathering system, and three Antero compressor stations. Gathering throughput volumes increased from 73.1 Bcf, or 200 MMcf per day, in 2013 to 349.7 Bcf, or 958 MMcf per day in 2014. Compression throughput volumes increased from 9.9 Bcf, or 27 MMcf per day, in 2013 to 38.1 Bcf, or 104 MMcf per day, in 2014. Total operating expenses related to gathering and compression increased from $36.5 million in 2013 to $74.5 million in 2014 as a result of the increased throughput volumes.

Fresh Water Distribution

Revenue for the fresh water distribution segment increased from $35.9 million for the year ended December 31, 2013 to $171.9 million for the year ended December 31, 2014, an increase of $136.0 million. The increase was due driven by the build out of the water system and resulting increased use of the water system in our hydraulic fracturing activities and the addition of a third-party customer. The volume of water delivered through the system increased from 10.5 MMBbls in 2013 to 48.7 MMBbls in 2014. Operating expenses for the fresh water distribution system increased from $19.5 million in 2013 to $61.2 million in 2014 as a result of the increased use of the system.

Marketing

In 2014, we began to purchase and sell third-party natural gas and NGLs and market our excess firm transportation capacity in order to optimize the revenues from these assets. Marketing revenues of $54 million and expenses of $103 million for the year ended December 31, 2014 relate to these activities. Marketing costs include firm transportation costs related to current excess capacity as well as the cost of third-party purchased gas and NGLs. This includes firm transportation costs of $43 million for the year ended December 31, 2014 related to an ethane transportation contract which is not being utilized because we are not currently recovering ethane. We enter into long-term firm transportation agreements for a significant part of our current and expected future production in order to secure guaranteed capacity to favorable markets.

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Year Ended December 31, 2012 Compared to Year Ended December 31, 2013

The following table sets forth selected operating data for the year ended December 31, 2012 compared to the year ended December 31, 2013:

(in thousands, except per unit and production data)	Year ended December 31, 2012	2013	Amount of Increase (Decrease)	Percent Change
Operating revenues:				
Natural gas sales	$ 259,743	689,198	429,455	165 %
NGL sales	3,719	111,663	107,944	2,903 %
Oil sales	1,520	20,584	19,064	1,254 %
Commodity derivative fair value gains	179,546	491,689	312,143	174 %
Gain on sale of assets	291,190	—	(291,190)	*
Total operating revenues	735,718	1,313,134	577,416	78 %
Operating expenses:				
Lease operating	6,243	9,439	3,196	51 %
Gathering, compression, processing, and transportation	91,094	218,428	127,334	140 %
Production and ad valorem taxes	20,210	50,481	30,271	150 %
Exploration	14,675	22,272	7,597	52 %
Impairment of unproved properties	12,070	10,928	(1,142)	(9) %
Depletion, depreciation, and amortization	102,026	233,876	131,850	129 %
Accretion of asset retirement obligations	101	1,065	964	954 %
General and administrative (before equity-based compensation)	45,284	60,158	14,874	33 %
Equity-based compensation	—	365,280	365,280	*
Total operating expenses	291,703	971,927	680,224	233 %
Operating income	444,015	341,207	(102,808)	(23) %
Other Expenses:				
Interest expense	(97,510)	(136,617)	(39,107)	40 %
Loss on early extinguishment of debt	—	(42,567)	(42,567)	*
Total other expenses	(97,510)	(179,184)	(81,674)	84 %
Income before income taxes and discontinued operations	346,505	162,023	(184,482)	(53) %
Income tax expense	(121,229)	(186,210)	(64,981)	54 %
Income (loss) from continuing operations	225,276	(24,187)	(249,463)	*
Income (loss) from discontinued operations	(510,345)	5,257	515,602	*
Net loss and comprehensive loss	$ (285,069)	(18,930)	266,139	*
Adjusted EBITDAX from continuing operations (1)	$ 284,710	$ 649,358	$ 364,648	128 %
Adjusted EBITDAX from discontinued operations (1)	149,605	—	(149,605)	*
Adjusted EBITDAX (1)	$ 434,315	$ 649,358	$ 215,043	128 %
Production data:				
Natural gas (Bcf)	87	177	90	103 %
NGLs (MBbl)	71	2,123	2,051	2,872 %
Oil (MBbl)	19	226	207	1,094 %
Combined (Bcfe)	87	191	103	118 %

Daily combined production (MMcfe/d)	239	522	283	119	%
Average prices before effects of hedges(2):					
Natural gas (per Mcf)	$ 2.99	$ 3.90	$ 0.91	30	%
NGLs (per Bbl)	$ 52.07	$ 52.61	$ 0.54	1	%
Oil (per Bbl)	$ 80.34	$ 91.27	$ 10.93	14	%
Combined (per Mcfe)	$ 3.03	$ 4.31	$ 1.28	42	%
Average realized prices after effects of hedges(2):					
Natural gas (per Mcf)	$ 5.05	$ 4.82	$ (0.23)	(5)	%
NGLs (per Bbl)	$ 52.07	$ 52.61	$ 0.54	1	%
Oil (per Bbl)	$ 80.34	$ 99.06	$ 18.72	23	%
Combined (per Mcfe)	$ 5.08	$ 5.17	$ 0.09	2	%
Average Costs (per Mcfe):					
Lease operating	$ 0.07	$ 0.05	$ (0.02)	(29)	%
Gathering, compression, processing, and transportation	$ 1.04	$ 1.15	$ 0.11	11	%
Production and ad valorem taxes	$ 0.23	$ 0.26	$ 0.03	13	%
Depletion, depreciation, amortization, and accretion	$ 1.17	$ 1.23	$ 0.06	5	%
General and administrative (before equity-based compensation)	$ 0.52	$ 0.32	$ (0.20)	(38)	%

(1) See “Item 6. Selected Financial Data” included elsewhere in this report for a definition of EBITDAX (a non GAAP measure) and a reconciliation of EBITDAX to net income (loss).

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(2) Average sales prices shown in the table reflect both the before and after effects of our cash settled derivatives. Our calculation of such after effects includes gains or losses on cash settlements for commodity derivatives, which do not qualify for hedge accounting because we do not designate or document them as hedges for accounting purposes. Oil and NGL production was converted at 6 Mcf per Bbl to calculate total Bcfe production and per Mcfe amounts. This ratio is an estimate of the equivalent energy content of the products and does not necessarily reflect their relative economic value.

*Not meaningful or applicable.

Natural gas, NGLs, and oil sales. Combined revenues from production of natural gas, NGLs, and oil increased from $265 million for the year ended December 31, 2012 to $821 million for the year ended December 31, 2013, an increase of $556 million, or 210%. Our production increased by 119% from 87 Bcfe, or 239 MMcfe per day, in 2012 to 191 Bcfe, or 522 MMcfe per day, in 2013. Increased production volumes increased revenues by $313 million, or 118%, (calculated as the increase in year to year volumes times the prior year average price), and combined commodity price increases accounted for a $243 million, or 92% increase in revenues (calculated as the change in year to year average combined price times current year production volumes).

Commodity derivative fair value gains. To achieve more predictable cash flows and to reduce our exposure to downward price fluctuations, we enter into derivative contracts using fixed for variable swap contracts when management believes that favorable future sales prices for our natural gas and oil production can be secured. Because we do not designate these derivatives as accounting hedges, they do not receive accounting hedge treatment, and all mark to market gains or losses, as well as cash receipts or payments on settled derivative instruments, are recognized in our results of operations. For the years ended December 31, 2012 and 2013, our hedges resulted in derivative fair value gains of $180 million and $492 million, respectively. The derivative fair value gains included $178 million and $164 million of cash settlements received on derivatives for the years ended December 31, 2012 and 2013, respectively. Commodity derivative fair value gains or losses will vary based on future commodity prices and have no cash flow impact until the derivative contracts are settled. We expect continued volatility in the fair value of our derivative instruments.

Gain on sale of Appalachian gathering assets. On March 26, 2012, we closed the sale of a portion of our Marcellus Shale gathering system assets along with exclusive rights to gather and compress our gas for a 20 year period within an area of dedication ("AOD") to a joint venture owned by Crestwood Midstream Partners and Crestwood Holdings Partners LLC (together, "Crestwood") for $375 million (excluding customary purchase price adjustments). A gain on the sale of the assets of $291 million was recorded in 2012. Under the terms of the contract, we earned additional proceeds of $40 million if certain volume thresholds were met by December 31, 2014. As the volume thresholds were fully met during 2014, we recorded an additional $40 million of gain on the sale of assets in 2014 and a receivable from Crestwood for a like amount.

Lease operating expenses. Lease operating expenses increased from $6 million for the year ended December 31, 2012 to $9 million in 2013, primarily as a result of increased production. On a per Mcfe basis, lease operating expenses decreased by 29%, from $0.07 per Mcfe in 2012 to $0.05 per Mcfe in 2013. Lease operating expenses increase as a larger proportion of wells have been on production for longer periods of time compared to 2012. Lease operating expenses are expected to continue to slowly increase on a per unit basis as the properties mature and production declines on a per well basis.

Gathering, compression, processing, and transportation expense. Gathering, compression, processing, and transportation expense increased from $91 million for the year ended December 31, 2012 to $218 million in 2013. The increase in these expenses resulted from the increase in production, firm transportation commitments, and third party compression and gathering expenses. On a per Mcfe basis, total gathering, compression, processing and transportation expenses increased from $1.04 per Mcfe for 2012 to $1.15 in 2013 due to additional processing costs and firm transportation commitments.

Production and ad valorem tax expense. Total production taxes increased from $20 million for the year ended December 31, 2012 to $50 million for the year ended December 31, 2013, primarily as a result of increased production. Production taxes as a percentage of natural gas, NGLs, and oil revenues before the effects of hedging were 6.1% for the year ended December 31, 2013 compared to 7.6% for the year ended December 31, 2012. Production taxes decreased as a percentage of revenues as production increased in Ohio, which has a lower severance tax rate than West Virginia, and per unit taxes also decreased as a percentage of revenues as prices increased. Ad valorem taxes increased because of the construction of the water distribution assets. Legislative proposals in the State of Ohio to increase severance taxes on production from horizontally fractured wells could increase our future production tax rates, if such legislation is enacted.

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Exploration expense. Exploration expense increased from $15 million for the year ended December 31, 2012 to $22 million for the year ended December 31, 2013 primarily because of an increase in the cost of unsuccessful lease acquisition efforts as we materially increased the number of contract lease brokers providing services to us in the Appalachian Basin.

Impairment of unproved properties. Impairment of unproved properties was approximately $11 million for the year ended December 31, 2013 compared to $12 million for the year ended December 31, 2012. We charge impairment expense for expired or soon to be expired leases when we determine they are impaired based on factors such as remaining lease terms, reservoir performance, commodity price outlooks or future plans to develop the acreage and recognize impairment costs accordingly.

DD&A. DD&A increased from $102 million for the year ended December 31, 2012 to $234 million for the year ended December 31, 2013, an increase of $132 million, as a result of increased production in 2013 compared to 2012. DD&A per Mcfe increased 5%, from $1.17 per Mcfe during 2012 to $1.23 per Mcfe during 2013 as a result of increased depreciation on growing gathering and water systems and facilities and increased proved property costs subject to depletion.

We evaluate the impairment of our proved natural gas, NGLs, and oil properties on a field by field basis whenever events or changes in circumstances indicate that a property's carrying amount may not be recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we reduce the carrying amount of the oil and gas properties to their estimated fair value. There were no impairment expenses recorded for the years ended December 31, 2012 or 2013 for proved properties. As of December 31, 2013, no significant exploratory well costs had been deferred for over one year pending proved reserves determination.

General and administrative expense. General and administrative expense (before equity-based compensation) increased from $45 million for the year ended December 31, 2012 to $60 million during 2013, an increase of $15 million. The increase is due to increased costs related to salaries, employee benefits, contract personnel and other general business expenses required to support the growth of our capital expenditure program and production levels. The number of our full time employees grew from 150 at December 31, 2012 to 233 at December 31, 2013. On a per Mcfe basis, general and administrative expense (before equity-based compensation) decreased by 38%, from $0.52 per Mcfe during the year ended December 31, 2012 to $0.32 per Mcfe during 2013 primarily due to a 119% growth in production. No portion of general and administrative expenses was allocated to discontinued operations as we did not expect any reduction of such expenses as a result of the sale of the Arkoma and Piceance properties. When all discontinued operations are included, general and administrative expenses were $0.37 per Mcfe in 2012.

In 2013, we recognized noncash equity-based compensation expense of approximately $365 million, almost all of which was related to the interests of our employees in Antero Employee Holdings LLC ("Employee Holdings"), which owns interests in Antero Investment LLC ("Antero Investment"). Prior to our IPO, the interests of Employee Holdings were subject to performance and service conditions which could be met generally only in the event of a liquidation or distribution event. In connection with our IPO, the terms of the Antero Investment operating agreement provided for a mechanism by which the shares of our common stock to be allocated amongst the members of Antero Investment, including Employee Holdings, will be specifically determined. As a result, the satisfaction of all performance and service conditions relative to the membership interests of Employee Holdings in Antero Investment became probable. Accordingly, we recognized approximately $365 million of equity-based compensation expense in 2013 relative to these interests and will recognize approximately another $121 million over the remaining expected service period. The equity-based compensation relative to these interests is treated as a capital contribution from Antero Investment in our financial statements and is not deductible for Federal or state income tax purposes in 2013 or in the future.

Interest expense and loss on early extinguishment of debt. Interest expense increased from $98 million for the year ended December 31, 2012 to $137 million for the year ended December 31, 2013, an increase of $39 million as a result of an increase in the amount of senior notes outstanding and the average balance of the revolving credit facility outstanding during 2013 compared to 2012. During 2013, we incurred a loss of $43 million on the early extinguishment of debt resulting from (i) the retirement of $140 million of the 7.25% senior notes due 2019 from the proceeds of our IPO and (ii) the retirement of the 9.375% senior notes due 2017 having a principal amount of $525 million from the proceeds of the issuance of the 5.375% notes due 2021. The loss of $43 million is comprised of redemption premiums of $35 million and the write off of deferred financing costs and unamortized premium and discounts of $8 million.

Income tax expense. Income tax expense related to continuing operations was $186 million (84% of pre tax income) in 2013 compared to $121 million (35% of pre tax income) in 2012. Income tax expense increased from 35% of pre tax income to 115% of pre tax income because the equity-based compensation expense recognized in 2013, related to the allocation of shares among the members of Antero Investment and Employee Holdings, is a nondeductible permanent difference between our taxable income and income recognized for financial statements. Although we have accrued $11 million at December 31, 2013 for unrecognized tax benefits, no taxes were due at the end of either December 31, 2012 or 2013. We have not generated current taxable income in either the current or prior years, which is primarily attributable to the differing book and tax treatment of unrealized derivative gains and intangible drilling costs. At December 31, 2013, we had approximately $1.2 billion of U.S. federal and state net operating loss carryforwards, which expire starting in 2024 and continue through 2033. At December 31, 2013, we recorded valuation allowances of approximately $27 million for deferred tax assets primarily related to state loss carryforwards in states where we no longer operate. From time to time there has been proposed legislation in the U.S. Congress to delay or limit future deductions for intangible drilling costs; such legislation could significantly affect our future taxable position if passed. The impact of any change will be recorded in the period that such legislation might be enacted.

The calculation of our tax liabilities involves uncertainties in the application of complex tax laws and regulations. We give financial statement recognition to those tax positions that we believe are more likely than not to be sustained upon examination by the Internal Revenue Service or state revenue authorities. The financial statements include unrecognized benefits at December 31, 2013 of $11 million that, if recognized, would result in a reduction of current income taxes payable and an increase in noncurrent deferred tax liabilities. No impact to our 2013 effective tax rate would result. As of December 31, 2013, approximately $0.5 million of interest has been accrued on unrecognized tax benefits.

The tax returns of Antero Resources Finance Corporation (which was merged with the Antero Resources Corporation in December 2013) are being examined by the Internal Revenue Service for its tax years 2011 and 2012. The Company's state tax returns are being examined by West Virginia taxing authorities for tax years 2010 through 2012. The Company does not expect any material adjustments to tax liabilities will result from either the federal or the state examination.

Income (loss) from discontinued operations. Income (loss) from discontinued operations includes the results of operations from the Arkoma Basin and Piceance Basin operations (including revenues and direct operating expenses and allocated income tax expense, but not general and administrative or interest expenses) and, in 2012, the loss on the sale of these assets. An analysis of these operations is included in note 3 to the consolidated financial statements included elsewhere in this report. Income (loss) from discontinued operations was $(510) million in 2012, primarily as a result of the loss on the sale of the properties of $796 million and a $273 million tax benefit from the loss. Income from discontinued operations of $5 million in 2013 resulted from the reduction of various liability provisions made in connection with the sale of $8 million, net of tax benefits of $3 million and final purchase price adjustments.

Adjusted EBITDAX from continuing and discontinued operations. Adjusted EBITDAX from continuing operations increased to $649 million for the year ended December 31, 2013 from $285 million for the year ended December 31, 2012, an increase of 128%. The increase in Adjusted EBITDAX resulted from a 119% increase in production, a 2% increase in the average per Mcfe price received after the impact of cash settled derivatives, net of the related increases in cash operating and general and administrative expenses. Adjusted EBITDAX from discontinued operations related to the Piceance and Arkoma Basin assets disposed of in 2012 was $150 million for the year ended December 31, 2012. See "Item 6. Selected Financial Data" included elsewhere in this report for a definition of EBITDAX (a non GAAP measure) and a reconciliation of EBITDAX to net income (loss).

Capital Resources and Liquidity

Historically, our primary sources of liquidity have been through issuances of debt and equity securities, borrowings under our revolving credit facility, asset sales, and net cash provided by operating activities. During 2014, we raised capital through the issuance of $1.1 billion of 5.125% senior notes due 2022, and the initial public offering of our subsidiary, Antero Midstream Partners LP, receiving net proceeds of $1.1 billion. Our primary use of cash has been for the exploration, development and acquisition of natural gas, NGLs, and oil properties as well as for development of gathering, compression, and fresh water system infrastructure. As we pursue reserve and production growth, we continually monitor what capital resources, including equity and debt financings, are available to meet our future financial obligations, planned capital expenditure activities and liquidity requirements. Our future success in growing proved reserves and production will be highly dependent on the capital resources available to us.

As of December 31, 2014, we had 5,331 potential horizontal well locations, which will take many years to develop. More specifically, our proved undeveloped reserves will require an estimated $8.2 billion of development capital over the next five years in order to fully develop the properties associated with our proved reserves. A significant portion of this capital requirement will be funded out of operating cash flows. However, we may be required to generate or raise significant capital to develop our proved undeveloped reserves.

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Our revolving credit facility has a borrowing base of $4.0 billion and current lender commitments of $4.0 billion. The borrowing base is determined every six months based on reserves, oil and gas commodity prices, and the value of our hedge portfolio. The next redetermination of the borrowing base is scheduled to occur in October 2015. For a discussion of the risks of a decrease in the borrowing base under our revolving credit facility, see "Item 1A. Risk Factors—The borrowing base under our revolving credit facility may be reduced in light of recent commodity price declines, which could hinder or prevent us from meeting our future capital needs." Our commodity hedge position provides us with additional liquidity as it provides us with the relative certainty of receiving a significant portion of our future expected revenues from operations despite potential declines in the price of natural gas, NGLs, or oil. Our ability to make significant additional acquisitions for cash would require us to obtain additional equity or debt financing, which we may not be able to obtain on terms acceptable to us, or at all. Our revolving credit facility is funded by a syndicate of 29 banks. We believe that the participants in the syndicate have the capability to fund up to their current commitment. If one or more banks should not be able to do so, we may not have the full availability of our revolving credit facility.

On November 10, 2014, Antero Midstream completed its IPO of 46,000,000 common units representing limited partner interests at a price to the public of $25.00 per Common Unit, including the exercise in full by the underwriters of their option to purchase an additional 6,000,000 common units. Antero Midstream owns gathering and compression assets that service our natural gas, NGLs, and condensate production. As of February 19, 2015, Antero and its affiliates owned 29,940,957 common units and all 75,940,957 subordinated units. The remaining 46,000,000 common units are held by the public.

The gross proceeds of the IPO were approximately $1.2 billion. After subtracting underwriting discounts and offering expenses of approximately $63 million, net proceeds received by Antero Midstream from its IPO were approximately $1.1 billion. Antero Midstream used approximately $843 million of the net proceeds to repay assumed indebtedness from Antero and reimburse Antero for certain capital expenditures incurred. Antero Midstream retained $250 million of the net proceeds for general partnership purposes.

For the year ended December 31, 2014, our total capital expenditures were approximately $4.1 billion, including drilling and completion costs of $2.5 billion, gathering and compression project costs of $558 million, fresh water distribution project costs of $197 million, $841 million on leasehold costs (including $415 million of acquisitions and $426 million on land), and other capital expenditures of $13 million. Our capital budget for 2015 is $1.8 billion, excluding the capital budget for Antero Midstream, and includes: $1.6 billion for drilling and completion; $50 million for fresh water distribution infrastructure; and $150 million for core leasehold acreage acquisitions. We do not budget for producing property acquisitions. Substantially all of the $1.6 billion allocated for drilling and completion is allocated to our operated drilling in liquids-rich gas areas. Approximately 60% of the drilling and completion budget is allocated to the Marcellus Shale, and the remaining 40% is allocated to the Utica Shale. During 2015, we plan to operate an average of nine drilling rigs in the Marcellus Shale and five drilling rigs in the Utica Shale. Additionally, the capital budget of Antero Midstream for 2015 is from $425 million to $450 million. We periodically review our capital expenditures and adjust our budget and its allocation based on liquidity, drilling results, leasehold acquisition opportunities, and commodity prices.

We believe that funds from operating cash flows and available borrowings under our revolving credit facility will be sufficient to meet our cash requirements, including normal operating needs, debt service obligations, capital expenditures, and commitments and contingencies for at least the next 12 months. For more information on our outstanding indebtedness, see "—Debt Agreements and Contractual Obligations."

Cash Flows

The following table summarizes our cash flows for the years ended December 31, 2012, 2013, and 2014:

	Year Ended December 31,		
(in thousands)	2012	2013	2014
Net cash provided by operating activities	$ 332,255	$ 534,707	$ 998,121
Net cash used in investing activities	(463,491)	(2,673,592)	(4,089,650)
Net cash provided by financing activities	146,882	2,137,383	3,320,021
Net increase (decrease) in cash and cash equivalents	$ 15,646	$ (1,502)	$ 228,492

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Cash Flow Provided by Operating Activities

Net cash provided by operating activities was $332 million, $535 million and $998 million for the years ended December 31, 2012, 2013 and 2014, respectively. The increase in cash flows from operations from 2012 to 2013 and also from 2013 to 2014 was primarily the result of increased revenues from oil and gas production and cash settled derivatives, net of increased operating expenses and interest expense and changes in working capital.

Our operating cash flow is sensitive to many variables, the most significant of which is the volatility of prices for natural gas, NGLs, and oil prices. Prices for these commodities are determined primarily by prevailing market conditions. Factors including regional and worldwide economic activity, weather, infrastructure capacity to reach markets, and other variables influence market conditions for these products. These factors are beyond our control and are difficult to predict. For additional information on the impact of changing prices on our financial position, see "Item 7A. Quantitative and Qualitative Disclosure About Market Risk."

Cash Flow Used in Investing Activities

During the years ended December 31, 2012, 2013, and 2014, we used cash flows in investing activities of $463 million, $2.7 billion, and $4.1 billion, respectively, as a result of our capital expenditures for drilling, development, acquisitions, and construction of midstream infrastructure. Net of proceeds from asset sales in 2012 of $1.2 billion, capital expenditures for drilling, development, and acquisition were $1.7 billion in 2012.

Our board of directors has approved a capital budget of $1.8 billion for 2015, which does not include the capital budget of $425 million to $450 million for Antero Midstream, our consolidated subsidiary. Our capital budget may be adjusted as business conditions warrant. The amount, timing and allocation of capital expenditures is largely discretionary and within our control. If natural gas, NGLs, and oil prices decline to levels below our acceptable levels or costs increase to levels above our acceptable levels, we could choose to defer a significant portion of our budgeted capital expenditures until later periods to achieve the desired balance between sources and uses of liquidity and prioritize capital projects that we believe have the highest expected returns and potential to generate near term cash flow. We routinely monitor and adjust our capital expenditures in response to changes in prices, availability of financing, drilling and acquisition costs, industry conditions, the timing of regulatory approvals, the availability of rigs, success or lack of success in drilling activities, contractual obligations, internally generated cash flow and other factors both within and outside our control.

Cash Flow Provided by Financing Activities

Net cash provided by financing activities in 2014 of $3.3 billion was primarily the result of (i) proceeds from the issuance of senior notes of $1.1 billion, (ii) net borrowings on our credit facilities of $1.4 billion, (iii) proceeds from the Antero Midstream IPO of $1.1 billion, net of (iv) $309 for retirements of senior notes and payments for early redemption premiums and deferred financing costs. The increase in cash and cash equivalents of $228 million in 2014 is primarily due to cash retained by Antero Midstream subsequent to its IPO. Antero Midstream had a cash balance of $230 million as of December 31, 2014.

Net cash provided by financing activities in 2013 of $2.1 billion was primarily the result of (i) proceeds from our IPO of $1.6 billion, (ii) proceeds from the issuance of senior notes of $1.2 billion, net of (iii) $744 million for retirements of senior notes and payments for early redemption premiums and deferred financing costs.

Net cash provided by financing activities in 2012 of $147 million was primarily the result of (i) $300 million of cash provided by the issuance of senior notes, net of (ii) net repayments of our revolving credit facility of $148 million and other items of $5 million, including deferred financing costs.

Debt Agreements and Contractual Obligations

Senior Secured Revolving Credit Facility. Our revolving credit facility (the "Credit Facility") provides for a maximum amount of $4.0 billion and at December 31, 2014 has a borrowing base of $4.0 billion. The borrowing base is redetermined semi annually and is dependent upon the amount of our proved oil and gas reserves and estimated cash flows from these reserves and our hedge positions. The next redetermination is scheduled to occur in October 2015. Current lender commitments are $4.0 billion. At December 31, 2014, we had $1.73 billion of borrowings and $387 million of letters of credit outstanding under the Credit Facility. The Credit Facility matures on May 5, 2019.

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On November 10, 2014, the Company and Antero Water LLC ("Antero Water"), a wholly-owned subsidiary of the Company, entered into a new water credit facility (the "Water Facility"), in order to provide for separate borrowings attributable to our fresh water distribution business. In accordance with the Credit Facility and the Water Facility agreements, borrowings under the Water Facility reduce availability under the Credit Facility on a dollar-for-dollar basis. The Water Facility will mature at the earlier of the sale of Antero Water to Midstream Operating LLC (a subsidiary of Antero Midstream Partners LP), or May 12, 2016.

Principal amounts borrowed on the Credit Facility and Water Facility are payable on the maturity dates with such borrowings bearing interest that is payable quarterly. We have a choice of borrowing in Eurodollars or at the base rate. Eurodollar loans bear interest at a rate per annum equal to the LIBOR Rate administered by the ICE Benchmark Administration for one, two, three, six or twelve months plus an applicable margin ranging from 150 to 250 basis points, depending on the percentage of our borrowing base utilized. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank's reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the rate for one month Eurodollar loans plus 100 basis points, plus an applicable margin ranging from 50 to 150 basis points, depending on the percentage of our borrowing base utilized. The amounts outstanding under the Credit Facility are secured by a first priority lien on substantially all of our natural gas, NGLs, and oil properties and associated assets and are cross guaranteed by each borrower entity along with each of their current and future wholly owned subsidiaries. The amounts outstanding under the Water Facility are secured by a first priority lien on substantially all of our water distribution assets and are cross-guaranteed by each borrower entity along with each of their current and future wholly owned subsidiaries. For information concerning the effect of changes in interest rates on interest payments under these facilities, see "Item 7A. Quantitative and Qualitative Disclosure About Market Risk." As of December 31, 2014, we had $1.73 billion of borrowings and $387 million letters of credit outstanding under the Credit Facility and Water Facility, with a weighted average interest rate of 2.06%.

The Credit Facility and Water Facility contain restrictive covenants that may limit our ability to, among other things:

- incur additional indebtedness;
- sell assets;
- make loans to others;
- make investments;
- enter into mergers;
- pay dividends;
- hedge future production;
- incur liens; and
- engage in certain other transactions without the prior consent of the lenders.

The Credit Facility and Water Facility also require us to maintain the following two financial ratios:

- a current ratio, which is the ratio of our consolidated current assets (including any unused borrowing base under the facilities and excluding derivative assets) to our consolidated current liabilities, of not less than 1.0 to 1.0 as of the end of each fiscal quarter; and
- a minimum interest coverage ratio, which is the ratio of consolidated EBITDAX to consolidated interest expense over the most recent four quarters, of not less than 2.5 to 1.0.

We were in compliance with such covenants and ratios as of December 31, 2013 and 2014. The actual borrowing capacity available to use may be limited by these current ratio and minimum interest coverage ratio covenants. At December 31, 2014, our current ratio was 2.57 to 1.0 (based on the $4.0 billion borrowing base in effect as of December 31, 2014) and our interest coverage ratio was 7.56 to 1.0.

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Midstream Credit Facility. On November 10, 2014, in connection with the closing of its IPO, Antero Midstream entered into a new revolving credit facility (the "Midstream Facility") among Antero Midstream, certain lenders party thereto, Wells Fargo Bank, National Association, as administrative agent, letter of credit issuer and swing line lender, and 16 other financial institutions thereto. The Midstream Facility provides for lender commitments of $1.0 billion and for a letter of credit sublimit of $150 million. There were no borrowings or letters of credit outstanding under the Midstream Facility as of December 31, 2014. The Midstream Facility will mature on November 10, 2019.

Principal amounts borrowed are payable on the maturity date with such borrowings bearing interest that is payable quarterly. Antero Midstream has a choice of borrowing in Eurodollars or at the base rate. Eurodollar loans bear interest at a rate per annum equal to the LIBOR Rate administered by the ICE Benchmark Administration for one, two, three, six or twelve months plus an applicable margin ranging from 150 to 225 basis points, depending on the leverage ratio then in effect. Base rate loans bear interest at a rate per annum equal to the greatest of (i) the agent bank's reference rate, (ii) the federal funds effective rate plus 50 basis points and (iii) the rate for one month Eurodollar loans plus 100 basis points, plus an applicable margin ranging from 50 to 125 basis points, depending on the leverage ratio then in effect.

The Midstream Facility is secured by mortgages on substantially all of Antero Midstream's and its restricted subsidiaries' properties – primarily assets used in the provision of gathering and compression services to the Company and third parties – and guarantees from its restricted subsidiaries. The Midstream Facility is not guaranteed by Antero Resources Corporation. Interest is payable at a variable rate based on LIBOR or the prime rate based on Antero Midstream's election at the time of borrowing. The Midstream Facility contains restrictive covenants that may limit Antero Midstream's ability to, among other things:

- incur additional indebtedness;
- sell assets;
- make loans to others;
- make investments;
- enter into mergers;
- make certain restricted payments;

incur liens; and

engage in certain other transactions without the prior consent of the lenders.

Borrowings under the Midstream Facility also require Antero Midstream to maintain the following financial ratios:

an interest coverage ratio, which is the ratio of Antero Midstream's consolidated EBITDA to its consolidated current interest charges of at least 2.5 to 1.0 at the end of each fiscal quarter; provided that upon obtaining investment grade rating, the borrower may elect not to be subject to such ratio;

a consolidated total leverage ratio, which is the ratio of consolidated debt to consolidated EBITDA, of not more than 5.0 to 1.0; provided that after electing to issue unsecured high yield notes, the consolidated total leverage ratio will not be more than 5.25 to 1.0, or, following the election of the borrower for two fiscal quarters after a material acquisition, 5.50 to 1.0; and

if Antero Midstream elects to issue unsecured high yield notes, a consolidated senior secured leverage ratio, which is the ratio of consolidated senior secured debt to consolidated EBITDA, of not more than 3.75 to 1.0.

Antero Midstream was in compliance with such covenants and ratios as of December 31, 2014.

Senior Notes. We have $525 million of 6.00% senior notes outstanding, which are due December 1, 2020. The 2020 notes are unsecured and effectively subordinated to the Credit Facility and the Water Facility to the extent of the value of the collateral securing such facilities. The 2020 notes rank pari passu to our other outstanding senior notes. The 2020 notes are guaranteed on a senior unsecured basis by our wholly-owned subsidiaries and certain of our future restricted subsidiaries. Interest on the 2020 notes is payable on June 1 and December 1 of each year. We may redeem all or part of the 2020 notes at any time on or after December 1, 2015 at redemption prices ranging from 104.50% on or after December 1, 2015 to 100.00% on or after December 1, 2018. In addition, on or before December 1, 2015, we may redeem up to 35% of the aggregate principal amount of the 2020 notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 106.00% of the principal amount of the 2020 notes, plus accrued interest. At any time prior to December 1, 2015, we may redeem the 2020 notes, in whole or in part, at a price equal to 100% of the principal amount of the 2020 notes plus a "make-whole" premium and accrued interest. If we undergo a change of control, the holders of the 2020 notes will have the right to require us to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2020 notes, plus accrued interest.

We also have $1 billion of 5.375% senior notes outstanding, which are due November 1, 2021. The 2021 notes are unsecured and effectively subordinated to the Credit Facility and the Water Facility to the extent of the value of the collateral securing such facilities. The 2021 notes rank parri passu to our other outstanding senior notes. The 2021 notes are guaranteed by our wholly-owned subsidiaries and certain of our future restricted subsidiaries. Interest on the 2021 notes is payable on May 1 and November 1 of each year. We may redeem all or part of the 2021 notes at any time on or after November 1, 2016 at redemption prices ranging from 104.031% on or after November 1, 2016 to 100.00% on or after November 1, 2019. In addition, on or before November 1, 2016, we may redeem up to 35% of the aggregate principal amount of the 2021 notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 105.375%. At any time prior to November 1, 2016, we may also redeem the 2021 notes, in whole or in part, at a price equal to 100% of the principal amount of the 2021 notes plus a "make-whole" premium and accrued interest. If we undergo a change of control prior to May 1, 2015, we may redeem all, but not less than all, of the 2021 notes at a redemption price equal to 110% of the principal amount of the 2021 notes. If we undergo a change of control, we may be required to offer to purchase the 2021 notes from the holders at a price equal to 101% of the principal amount of the 2021 notes, plus accrued interest.

We also have $1.1 billion of 5.125% senior notes outstanding, which are due December 1, 2022. The 2022 notes are unsecured and effectively subordinated to the Credit Facility and the Water Facility to the extent of the value of the collateral securing such facilities. The 2022 notes rank parri passu to our other outstanding senior notes. The 2022 notes are guaranteed by our wholly-owned subsidiaries and certain of our future restricted subsidiaries. Interest on the 2022 notes is payable on June 1 and December 1 of each year. We may redeem all or part of the 2021 notes at any time on or after June 1, 2017 at redemption prices ranging from 103.844% on or after June 1, 2017 to 100.00% on or after June 1, 2020. In addition, on or before June 1, 2017, we may redeem up to 35% of the aggregate principal amount of the 2022 notes with the net cash proceeds of certain equity offerings, if certain conditions are met, at a redemption price of 105.125%. At any time prior to June 1, 2017, we may also redeem the 2022 notes, in whole or in part, at a price equal to 100% of the principal amount of the 2022 notes plus a "make-whole" premium and accrued interest. If we undergo a change of control prior to December 1, 2015, we may redeem all, but not less than all, of the 2022 notes at a redemption price equal to 110% of the principal amount of the 2022 notes. If we undergo a change of control, the holders of the 2022 notes will have the right to require us to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the 2022 notes, plus accrued interest.

We used the proceeds from the issuances of the senior notes to repay borrowings outstanding under the Credit Facility, redeem previously issued senior notes, and for development of our oil and natural gas properties.

The senior notes indentures each contain restrictive covenants and restrict our ability to incur additional debt unless a pro forma minimum interest coverage ratio requirement of 2.25:1 is maintained. We were in compliance with such covenants as of December 31, 2013 and 2014.

Treasury Management Facility. We have a stand alone revolving note with a lender under the Credit Facility which provides for up to $25 million of cash management obligations in order to facilitate our daily treasury management. Borrowings under the revolving note are secured by the collateral for our revolving credit facility. Borrowings under the facility bear interest at the lender's prime rate plus 1.0%. The note matures on June 1, 2015. At December 31, 2013 and 2014, there were no outstanding borrowings under this facility.

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Contractual Obligations. A summary of our contractual obligations as of December 31, 2013 is provided in the following table (in millions).

(in millions)	Year 2015	2016	2017	2018	2019	Thereafter	Total
Credit Facility and Water Facility(1)	$ —	115	—	—	1,615	—	1,730
Senior notes—principal(2)	—	—	—	—	—	2,625	2,625
Senior notes—interest(2)	142	142	142	142	142	279	989
Drilling rig and frac service commitments(3)	212	161	96	—	—	—	469
Firm transportation (4)	316	593	800	867	939	10,376	13,891
Gas processing, gathering, and compression services (5)	336	237	245	244	193	1,040	2,295
Office and equipment leases	9	9	8	6	4	11	47
Asset retirement obligations(6)	—	—	—	—	—	17	17
Total	$ 1,015	1,257	1,291	1,259	2,893	14,348	22,063

(1) Includes outstanding principal amounts at December 31, 2014. This table does not include future commitment fees, interest expense or other fees on our Credit Facility and Water Facility because they are floating rate instruments and we cannot determine with accuracy the timing of future loan advances, repayments, or future interest rates to be charged.

(2) Includes the 6.00% notes due 2020, the 5.375% notes due 2021, and the 5.125% notes due 2022.

(3) Includes contracts for the services of drilling rigs and frac fleets, which expire at various dates from March 2015 through September 2017. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interest.

(4) Includes firm transportation agreements with various pipelines in order to facilitate the delivery of production to market. These contracts commit us to transport minimum daily natural gas or NGLs volumes at negotiated rates, or pay for any deficiencies at specified reservation fee rates. The amounts in this table represent our minimum daily volumes at the reservation fee rate. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interest.

(5) Contractual commitments for gas processing, gathering and compression services agreements represent minimum commitments under long-term gas processing agreements as well as various gas compression agreements. The values in the table represent the gross amounts that we are committed to pay; however, we will record in our financial statements our proportionate share of costs based on our working interest.

(6) Represents the present value of our estimated asset retirement obligations. Neither the ultimate settlement amounts nor the timing of our asset retirement obligations can be precisely determined in advance; however, we believe it is likely that a very small amount of these obligations will be settled within the next five years.

Critical Accounting Policies and Estimates

The discussion and analysis of our financial condition and results of operations are based upon our consolidated financial statements, which have been prepared in accordance with accounting principles generally accepted in the United States. The preparation of our financial statements requires us to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses and related disclosure of contingent assets and liabilities. Certain accounting policies involve judgments and uncertainties to such an extent that there is reasonable likelihood that materially different amounts could have been reported under different conditions, or if different assumptions had been used. We evaluate our estimates and assumptions on a regular basis. We base our estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying values of assets and liabilities that are not readily apparent from other sources. Actual results may differ from these estimates and assumptions used in preparation of our consolidated financial statements. We provide expanded discussion of our more significant accounting policies, estimates and judgments below. We believe these accounting policies reflect our more significant estimates and assumptions used in preparation of

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our consolidated financial statements. See note 2 to the consolidated financial statements for a discussion of additional accounting policies and estimates made by management.

Successful Efforts Method

The Company accounts for its natural gas and crude oil exploration and development activities under the successful efforts method of accounting. Under the successful efforts method, the costs incurred to acquire, drill, and complete productive wells, development wells, and undeveloped leases are capitalized. Oil and gas lease acquisition costs are also capitalized. Exploration costs, including personnel and other internal costs, geological and geophysical expenses, delay rentals for gas and oil leases, and costs associated with unsuccessful lease acquisitions are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when we determine that the well does not contain reserves in commercially viable quantities. The Company reviews exploration costs related to wells in progress at the end of each quarter and makes a determination, based on known results of drilling at that time, whether the costs should continue to be capitalized pending further well testing and results, or charged to expense. We have not incurred any such charges in the years ended December 31, 2012, 2013, and 2014. The sale of a partial interest in a proved property is accounted for as a cost recovery, and no gain or loss is recognized as long as this treatment does not significantly affect the units of production amortization rate. A gain or loss is recognized for all other sales of producing properties.

Unproved properties with significant acquisition costs are assessed for impairment on a property by property basis, and any impairment in value is charged to expense. Impairment is assessed based on remaining lease terms, drilling results, reservoir performance, commodity price outlooks, and future plans to develop acreage. Other unproved properties are assessed for impairment on an aggregate basis. Unproved properties and the related costs are transferred to proved properties when reserves are discovered on or otherwise attributed to the property. Proceeds from sales of partial interests in unproved properties are accounted for as a recovery of cost without recognition of any gain or loss until the cost has been recovered. Impairment of unproved properties for leases which have expired, or are expected to expire, was $12.1 million, $10.9 million, and $15.2 million for the years ended December 31, 2012, 2013, and 2014, respectively.

The successful efforts method of accounting can have a significant impact on the operational results reported when we are entering a new exploratory area in anticipation of finding a gas and oil field that will be the focus of future development drilling activity. The initial exploratory wells may be unsuccessful and will be expensed if reserves are not found in economic quantities. Seismic costs can be substantial, which will result in additional exploration expenses when incurred. Additionally, the application of the successful efforts method of accounting requires managerial judgment to determine the proper classification of wells designated as developmental or exploratory, which will ultimately determine the proper accounting treatment of the costs incurred.

Natural Gas, NGLs and Oil Reserve Quantities and Standardized Measure of Future Cash Flows

Our internal technical staff prepare the estimates of natural gas, NGLs, and oil reserves and associated future net cash flows and our independent reserve engineers audit these estimates. Current accounting guidance allows only proved natural gas, NGLs, and oil reserves to be included in our financial statement disclosures. The SEC has defined proved reserves as the estimated quantities of natural gas, NGLs, and oil which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions. Our independent reserve engineers and internal technical staff must make a number of subjective assumptions based on their professional judgment in developing reserve estimates. Reserve estimates consider recent production levels and other technical information about each field. Natural gas, NGLs, and oil reserve engineering is a subjective process of estimating underground accumulations of natural gas, NGLs, and oil that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Periodic revisions to the estimated reserves and future cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, natural gas, NGLs, and oil prices, cost changes, technological advances, new geological or geophysical data, or other economic factors. Accordingly, reserve estimates are generally different from the quantities of natural gas, NGLs, and oil that are ultimately recovered. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly affect future amortization of capitalized costs and result in impairment of assets that may be material.

Impairment of Proved Properties

We review our proved natural gas, NGLs, and oil properties for impairment on a geological reservoir basis whenever events and circumstances indicate that a decline in the recoverability of their carrying value may have occurred. We estimate the expected future cash flows of our gas, NGLs, and oil properties and compare these future cash flows to the carrying amount of properties to

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determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, we will adjust the carrying amount of the properties to fair value. The factors used to determine fair value are subject to our judgment and expertise and include, but are not limited to, recent sales prices of comparable properties, the present value of future cash flows, net of estimated operating and development costs using estimates of proved reserves, future commodity pricing, future production estimates, anticipated capital expenditures, and various discount rates commensurate with the risk associated with realizing the expected cash flows projected. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges for proved properties may be recorded. We did not record any impairment charges for proved properties during the years ended December 31, 2012, 2013, and 2014.

New Accounting Pronouncements

On May 28, 2014, the FASB issued ASU No. 2014-09, Revenue from Contracts with Customers, which requires an entity to recognize the amount of revenue to which it expects to be entitled for the transfer of promised goods or services to customers. The ASI will replace most existing revenue recognition guidance in U.S. GAAP when it becomes effective. The new standard is effective for the Company on January 1, 2017. Early application is not permitted. The standard permits the use of either the retrospective or cumulative effect transition method. The Company is evaluating the effect that ASU 2014-09 will have on its consolidated financial statements and related disclosures. The Company has not yet selected a transition method nor has it determined the effect of the standard on its ongoing financial reporting.

Off Balance Sheet Arrangements

As of December 31, 2014, we did not have any off balance sheet arrangements other than operating leases and contractual commitments for drilling rigs, frac services, firm transportation, gas processing, and gathering and compression services. See "—Debt Agreements and Contractual Obligations—Contractual Obligations" for commitments under operating leases, drilling rig and frac service agreements, firm transportation agreements, gas processing, and gathering and compression service agreements.

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Item 7A. Quantitative and Qualitative Disclosures About Market Risk

The primary objective of the following information is to provide forward looking quantitative and qualitative information about our potential exposure to market risk. The term "market risk" refers to the risk of loss arising from adverse changes in natural gas, NGLs, and oil prices and interest rates. The disclosures are not meant to be precise indicators of expected future losses, but rather indicators of reasonably possible losses. This forward looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for hedging purposes, rather than for speculative trading.

Commodity Hedging Activities

Our primary market risk exposure is in the price we receive for our natural gas, NGLs, and oil production. Realized pricing is primarily driven by spot regional market prices applicable to our U.S. natural gas production and the prevailing worldwide price for crude oil. Pricing for natural gas, NGLs, and oil production has been volatile and unpredictable for several years, and we expect this volatility to continue in the future. The prices we receive for production depend on many factors outside of our control, including volatility in the differences between product prices at sales points and the applicable index price.

To mitigate some of the potential negative impact on our cash flow caused by changes in commodity prices, we enter into financial commodity swap contracts to receive fixed prices for a portion of our natural gas, NGLs, and oil production when management believes that favorable future prices can be secured. We hedge part of our production at a fixed price for natural gas at our sales points (New York Mercantile Exchange ("NYMEX") less basis) to mitigate the risk of differentials to the sales point prices. Part of our production is also hedged at NYMEX prices.

Our financial hedging activities are intended to support natural gas, NGLs, and oil prices at targeted levels and to manage our exposure to natural gas, NGLs, and oil price fluctuations. The counterparty is required to make a payment to us for the difference between the fixed price and the settlement price if the settlement price is below the fixed price. We are required to make a payment to the counterparty for the difference between the fixed price and the settlement price if the fixed price is below the settlement price. These contracts may include financial price swaps whereby we will receive a fixed price for our production and pay a variable market price to the contract counterparty, cashless price collars that set a floor and ceiling price for the hedged production, or basis differential swaps. If the applicable monthly price indices are outside of the ranges set by the floor and ceiling prices in the various collars, we and the counterparty to the collars would be required to settle the difference. The Company was not party to any collars as of, or during the year ended, December 31, 2014.

At December 31, 2014, we had in place natural gas, oil, and propane swaps covering portions of our projected production from 2015 through 2020. Our commodity hedge position as of December 31, 2014 is summarized in note 8 to our consolidated financial statements included elsewhere herein. Our financial hedging activities are intended to support natural gas, NGLs, and oil prices at targeted levels and to manage our exposure to natural gas price fluctuations. As amended on February 17, 2015, our revolving credit facility allows us to hedge up to 75% of our projected oil and gas production for the next five years, and 65% of projected production in 2020. Based on our annual production and our fixed price swap contracts in place during 2014, our income before taxes for the year ended December 31, 2014 would have decreased by approximately $13 million for each $0.10 decrease per MMBtu in natural gas prices and $1.00 decrease per Bbl in oil and NGLs prices.

All derivative instruments, other than those that meet the normal purchase and normal sales exception, are recorded at fair market value in accordance with U.S. GAAP and are included in our consolidated balance sheets as assets or liabilities. The fair values of our derivative instruments are adjusted for non performance risk. Because we do not designate these derivatives as accounting hedges, they do not receive hedge accounting treatment; all mark to market gains or losses, as well as cash receipts or payments on settled derivative instruments, are recognized in our statements of operations. We present the total of realized and unrealized gains or losses on commodity derivatives in our operating revenues as “Commodity derivative fair value gains.”

Mark to market adjustments of derivative instruments produce earnings volatility but have no cash flow impact relative to changes in market prices until the derivative contracts are settled. We expect continued volatility in the fair value of our derivative instruments. Our cash flow is only impacted when the associated derivative instrument contract is settled by making or receiving a payment to or from the counterparty. At December 31, 2013 and 2014, the estimated fair value of our commodity derivative instruments was a net asset of $860 million and $1.6 billion, respectively, comprised of current and noncurrent assets and current liabilities. None of these commodity derivative instruments were entered into for trading or speculative purposes.

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By removing price volatility from a portion of our expected natural gas production through December 2020, we have mitigated, but not eliminated, the potential effects of changing prices on our operating cash flow for those periods. While mitigating negative effects of falling commodity prices, these derivative contracts also limit the benefits we would receive from increases in commodity prices above the hedge prices.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from commodity derivatives contracts ($1.6 billion at December 31, 2014), the sale of our oil and gas production ($192 million at December 31, 2014) which we market to energy companies, end users and refineries, and joint interest receivables ($116 million at December 31, 2014).

By using derivative instruments that are not traded on an exchange to hedge exposures to changes in commodity prices, we expose ourselves to the credit risk of our counterparties. Credit risk is the potential failure of the counterparty to perform under the terms of the derivative contract. When the fair value of a derivative contract is positive, the counterparty is expected to owe us, which creates credit risk. To minimize the credit risk in derivative instruments, it is our policy to enter into derivative contracts only with counterparties that are creditworthy financial institutions deemed by management as competent and competitive market makers. The creditworthiness of our counterparties is subject to periodic review. We have economic hedges in place with ten different counterparties, all of which are lenders under our Credit Facility. The fair value of our commodity derivative contracts of approximately $1.6 billion at December 31, 2014 includes the following values by bank counterparty: Credit Suisse—$268 million; Barclays—$257 million; JP Morgan—$253 million; BNP Paribas—$233 million; Citigroup—$231 million; Wells Fargo—$21 million; Scotiabank—$77 million; Fifth Third Bank—$31 million; Toronto Dominion Bank—$28 million; Bank of Montreal—$4 million. The credit ratings of certain of these banks were downgraded in recent years because of the sovereign debt crisis in Europe. The estimated fair value of our commodity derivative assets has been risk adjusted using a discount rate based upon the respective published credit default swap rates (if available, or if not available, a discount rate based on the applicable Reuters bond rating) at December 31, 2014 for each of the European and American banks. We believe that all of these institutions currently are acceptable credit risks. Other than as provided by our revolving credit facility, we are not required to provide credit support or collateral to any of our counterparties under our derivative contracts, nor are they required to provide credit support to us. As of December 31, 2014, we did not have past due receivables from, or payables to, any of the counterparties to our derivative contracts.

We are also subject to credit risk due to concentration of our receivables from several significant customers for sales of natural gas. We, generally, do not require our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial results.

Joint interest receivables arise from billing entities who own partial interest in the wells we operate. These entities participate in our wells primarily based on their ownership in leased properties on which we wish to drill. We can do very little to choose who participates in our wells.

Interest Rate Risks

Our primary exposure to interest rate risk results from outstanding borrowings under our Credit Facility and Water Facility, and the Midstream Facility of our subsidiary, Antero Midstream. Each of these credit facilities has a floating interest rate. The average annual interest rate incurred on this indebtedness for the year ended December 31, 2014 was approximately 1.99%. A 1.0% increase in each of the applicable average interest rates for the year ended December 31, 2014 would have resulted in an estimated $11 million increase in interest expense for that period.

Item 8. Financial Statements and Supplementary Data

The Report of Independent Registered Public Accounting Firm, Consolidated Financial Statements and supplementary financial data required for this Item are set forth beginning on page F 1 of this report and are incorporated herein by reference.

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

Not applicable.

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Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures

As required by Rule 13a 15(b) under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a 15(e) and 15d 15(e) under the Exchange Act) as of the end of the period covered by this annual report. Our disclosure controls and procedures are designed to ensure that information required to be disclosed in the reports that we file or submit under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms. Based upon that evaluation, our principal executive officer and principal financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2014.

Changes in Internal Control Over Financial Reporting

There has been no change in our internal control over financial reporting (as defined in Rules 13a 15(f) and 15d 15(f) under the Exchange Act) during the fourth quarter of 2014 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Management's Annual Report on Internal Control Over Financial Reporting

The management of Antero Resources Corporation is responsible for establishing and maintaining adequate internal control over financial reporting for us as defined in Rules 13a 15(f) and 15d 15(f) of the Exchange Act. This system is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with accounting principles generally accepted in the United States of America.

Our internal control over financial reporting includes those policies and procedures that:

(i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect our transactions and dispositions of the assets;
(ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that our receipts and expenditures are being made only in accordance with authorizations of our management and Directors; and
(iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets that could have a material effect on the financial statements.

Because of its inherent limitations, a system of internal control over financial reporting can provide only reasonable assurance and may not prevent or detect all misstatements. Further, because of changes in conditions, effectiveness of internal controls over financial reporting may vary over time.

Under the supervision of, and with the participation of our management, including the Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework and criteria established in Internal Control—Integrated Framework in 2013, issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management of Antero Resources Corporation concluded that our internal control over financial reporting was effective as of December 31, 2014.

The effectiveness of our internal control over financial reporting as of December 31, 2014 has been audited by KPMG LLP, an independent registered public accounting firm which also audited our consolidated financial statements as of and for the year ended December 31, 2014, as stated in their report which appears on page F-3 in this report.

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Item 9B. Other Information

Disclosure Pursuant to Section 13(r) of the Exchange Act

Pursuant to Section 13(r) of the Securities Exchange Act of 1934, we, Antero Resources Corporation, may be required to disclose in our annual and quarterly reports to the Securities and Exchange Commission (the "SEC"), whether we or any of our "affiliates" knowingly engaged in certain activities, transactions or dealings relating to Iran or with certain individuals or entities targeted by US economic sanctions. Disclosure is generally required even where the activities, transactions or dealings were conducted in compliance with applicable law. Because the SEC defines the term "affiliate" broadly, it includes any entity under common "control" with us (and the term "control" is also construed broadly by the SEC).

The description of the activities below has been provided to us by Warburg Pincus LLC ("WP"), affiliates of which: (i) beneficially own more than 10% of our outstanding common stock and/or are members of our board of directors and (ii) beneficially own more than 10% of the equity interests of, and have the right to designate members of the board of directors of Endurance International Group ("EIG") and Santander Asset Management Investment Holdings Limited ("SAMIH"). EIG and SAMIH may therefore be deemed to be under common "control" with us; however, this statement is not meant to be an admission that common control exists.

The disclosure below relates solely to activities conducted by EIG and SAMIH and its non-U.S. affiliates that may be deemed to be under common "control" with us. The disclosure does not relate to any activities conducted by Antero Resources Corporation or by WP and does not involve our or WP's management. Neither us nor WP has had any involvement in or control over the disclosed activities of SAMIH, and neither us nor WP has independently verified or participated in the preparation of the disclosure. Neither us nor WP is representing as to the accuracy or completeness of the disclosure nor do we or WP undertake any obligation to correct or update it.

As to EIG

We understand that EIG's affiliates intend to disclose in their next annual or quarterly SEC report that:

"On July 2, 2013, the billing information for a subscriber account, or the Subscriber Accountc was updated to include Seyed Mahmoud Mohaddes, or Mohaddes. On September 16, 2013, the Office of Foreign Assets Control, or OFAC, designated Mohaddes as a Specially Designated National, or SDN, pursuant to 31 C.F.R. Part 560.304. On or around September 26, 2014, during a routine compliance scan of new and existing subscriber accounts, EIG discovered that Mohaddes, a SDN, was named as an account contact for the Subscriber Account. EIG promptly suspended the Subscriber Account, locked the domain name IOCUKLTD.COM, which was registered to the Subscriber Account, and reported the domain name to OFAC as potentially the property of a SDN subject to blocking pursuant to Executive Order 13599. Since September 16, 2013, when Mohaddes was added to the SDN list, charges in the total amount of $120.35 were made to the Subscriber Account for web hosting and domain privacy services. EIG has ceased billing for the Subscriber Account. To date, EIG has not received any correspondence from OFAC regarding this matter.

On July 10, 2014, OFAC designated each of Stars Group Holding, or Stars, and Teleserve Plus SAL, or Teleserve, as SDNs under Executive Order 13224, and their property became subject to blocking pursuant to the Global Terrorism Sanctions Regulations, 31 C.F.R. Part 594. On July 15, 2014, as part of EIG's compliance review processes, EIG discovered that the domain names associated with each of Stars, STARSCOM.NET, and Teleserve, TELESERVEPLUS.COM, or collectively, the Stars/Teleserve Domain Names, were registered through EIG's platform. EIG immediately took steps to suspend and lock the Stars/Teleserve Domain Names to prevent them from being transferred or resolving to a website, and EIG promptly reported the Domain Names as potentially blocked property to OFAC. EIG did not generate any revenue from the Stars/Teleserve Domain Names between when they were added to the SDN list on July 10, 2014 and when EIG discovered that they were registered through EIG's platform on July 15, 2014. To date, EIG has not received any correspondence from OFAC regarding the matter.

On July 15, 2014 during a compliance scan of all domain names on one of our platforms, EIG identified the domain name KAHANETZADAK.COM, or the Domain Name, which was listed as an 'also known as,' or AKA, of the entity Kahane Chai which operates as the American Friends of the United Yeshiva. Kahane Chai was designated as a SDN on November 2, 2001 pursuant to Executive Order 13224. Because the Domain Name was transferred into a

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customer account of one of EIG's resellers, there was no direct financial transaction between EIG and the registered owner of the Domain Name. The Domain Name was suspended upon EIG's discovering it on EIG's platform, and EIG reported the Domain Name to OFAC as potentially the property of a SDN. To date, EIG have not received any correspondence from OFAC regarding the matter."

As to SAMIH

We understand that SAMIH's affiliates intend to disclose in their next annual or quarterly SEC report that:

"Santander UK holds frozen savings and current accounts for three customers resident in the U.K. who are currently designated by the U.S. for terrorism. The accounts held by each customer were blocked after the customer's designation and remained blocked and dormant throughout 2014. No revenue has been generated by Santander UK on these accounts. The bank account held for one of these customers was closed in the fourth quarter of 2014.

An Iranian national, resident in the U.K., who is currently designated by the U.S. under the Iranian Financial Sanctions Regulations and the Weapons of Mass Destruction Proliferators Sanctions Regulations ("NPWMD sanctions program"), holds a mortgage with Santander UK that was issued prior to any such designation. No further drawdown has been made (or would be permitted) under this mortgage although Santander UK continues to receive repayment installments. In 2014, total revenue in connection with the mortgage was approximately £2,580 and net profits were negligible relative to the overall profits of Santander UK. The same Iranian national also holds two investment accounts with Santander Asset Management UK Limited. The accounts have remained frozen during 2014. The investment returns are being automatically reinvested, and no disbursements have been made to the customer. Total revenue for the Santander Group in connection with the investment accounts was £250 and net profits in 2014 were negligible relative to the overall profits of Banco Santander, S.A.

In addition, during the third quarter 2014, Santander UK identified two additional customers: a UK national designated by the U.S. under the NPWMD sanctions program held a business account. No transactions were made and the account was closed in the fourth quarter of 2014. No revenue or profit has been generated. A second UK national designated by the US for reasons of terrorism held a personal current account and a personal credit card account, both of which were closed in the third quarter of 2014. Although transactions took place on the current account during the third quarter of 2014, revenue and profits generated were negligible. No transactions took place on the credit card."

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PART III

Item 10. Directors, Executive Officers, and Corporate Governance

Pursuant to General Instruction G(3) to Form 10 K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2015 Annual Meeting of Stockholders.

Directors and Executive Officers

The following table sets forth names, ages and titles of our directors and executive officers as of December 31, 2014.

Name	Age	Title
Paul M. Rady	61	Chairman of the Board, Director and Chief Executive Officer
Glen C. Warren, Jr.	58	Director, President, Chief Financial Officer and Secretary
Kevin J. Kilstrom	60	Vice President—Production
Alvyn A. Schopp	56	Chief Administrative Officer and Regional Vice President
Ward D. McNeilly	64	Vice President—Reserves, Planning and Midstream
Peter R. Kagan	46	Director
W. Howard Keenan, Jr.	64	Director
Christopher R. Manning	47	Director
Richard W. Connor	65	Director
Robert J. Clark	69	Director
Benjamin A. Hardesty	65	Director
James R. Levy	38	Director

Set forth below is the description of the backgrounds of our directors and executive officers.

Paul M. Rady has served as Chief Executive Officer and Chairman of the Board of Directors since May 2004. Mr. Rady also served as Chief Executive Officer and Chairman of the Board of Directors of our predecessor company, Antero Resources Corporation, from its founding in 2002 to its ultimate sale to XTO Energy, Inc. in April 2005. Mr. Rady also serves as Chairman of the Board of Directors of the general partner of Antero Midstream Partners LP. Prior to Antero Resources Corporation, Mr. Rady served as President, CEO and Chairman of Pennaco Energy from 1998 until its sale to Marathon in early 2001. Prior to Pennaco, Mr. Rady was with Barrett Resources from 1990 until 1998 where he initially was recruited as Chief Geologist in 1990, then served as Exploration Manager, EVP Exploration, President, COO and Director and ultimately CEO. Mr. Rady began his career with Amoco where he served 10 years as a geologist focused on the Rockies and Mid Continent. Mr. Rady holds a B.A. in Geology from Western State College of Colorado and M.Sc. in Geology from Western Washington University.

Mr. Rady’s significant experience as a chief executive of oil and gas companies, together with his training as a geologist and broad industry knowledge, enable Mr. Rady to provide the board with executive counsel on a full range of business, strategic and professional matters.

Glen C. Warren, Jr. has served as President, Chief Financial Officer and Secretary and as a director since May 2004. Mr. Warren also served as President and Chief Financial Officer and as a director of our predecessor company, Antero Resources Corporation, from its founding in 2002 to its ultimate sale to XTO Energy, Inc. in April 2005. Mr. Warren also serves on the Board of Directors of the general partner of Antero Midstream Partners LP. Prior to Antero Resources Corporation, Mr. Warren served as EVP, CFO and Director of Pennaco Energy from 1998 until its sale to

Marathon in early 2001. Mr. Warren spent 10 years as a natural resources investment banker focused on equity and debt financing and M&A advisory with Lehman Brothers, Dillons Read & Co. Inc. and Kidder, Peabody & Co. Mr. Warren began his career as a landman in the Gulf Coast region with Amoco, where he spent six years. Mr. Warren holds a B.A. from the University of Mississippi, a J.D. from the University of Mississippi School of Law and an M.B.A. from the Anderson School of Management at U.C.L.A.

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Mr. Warren's significant experience as a chief financial officer of oil and gas companies, together with his experience as an investment banker and broad industry knowledge, enable Mr. Warren to provide the board with executive counsel on a full range of business, strategic, financial and professional matters.

Kevin J. Kilstrom has served as Vice President of Production since June 2007. Mr. Kilstrom was a Manager of Petroleum Engineering with AGL Energy of Sydney, Australia from 2006 to 2007. Prior to AGL, Mr. Kilstrom was with Marathon Oil as an Engineering Consultant and Asset Manager from 2003 to 2006 and as a Business Unit Manager for Marathon's Powder River coal bed methane assets from 2001 to 2003. Mr. Kilstrom also served as a member of the board of directors of three Marathon subsidiaries from October 2003 through May 2005. Mr. Kilstrom was an Operations Manager and reserve engineer at Pennaco Energy from 1999 to 2001. Mr. Kilstrom was at Amoco for more than 22 years prior to 1999. Mr. Kilstrom holds a B.S. in Engineering from Iowa State University and an M.B.A. from DePaul University.

Alvyn A. Schopp has served as Chief Administrative Officer, Regional Vice President, and Treasurer since September 2013. Mr. Schopp also served as Vice President of Accounting and Administration and Treasurer from January 2005 to September 2013, as Controller and Treasurer from 2003 to 2005 and as Vice President of Accounting and Administration and Treasurer of our predecessor company, Antero Resources Corporation, from January 2005 until its ultimate sale to XTO Energy, Inc. in April 2005. From 1993 to 2000, Mr. Schopp was CFO, Director and ultimately CEO of T Netix. From 1980 to 1993 Mr. Schopp was with KPMG LLP, most recently as a Senior Manager. Mr. Schopp holds a B.B.A. from Drake University.

Ward D. McNeilly serves as Vice President of Reserves, Planning & Midstream, and has been with the Company since October 2010. Mr. McNeilly has 34 years of experience in oil and gas asset management, operations, and reservoir management. From 2007 to October 2010, Mr. McNeilly was BHP Billiton's Gulf of Mexico Operations Manager. From 1996 through 2007, Mr. McNeilly served in various North Sea and Gulf of Mexico Deepwater operations and asset management positions with Amoco and then BP. Mr. McNeilly served in a number of different domestic and international positions with Amoco from 1979 to 1996. Mr. McNeilly holds a B.S. in Geological Engineering from the Mackay School of Mines at the University of Nevada.

Peter R. Kagan has served as a director since 2004. Mr. Kagan has been with Warburg Pincus since 1997 where he leads the firm's investment activities in energy and natural resources. He is a Partner of Warburg Pincus & Co. and a Managing Director of Warburg Pincus LLC. He is also a member of Warburg Pincus LLC's Executive Management Group. Mr. Kagan received a B.A. degree cum laude from Harvard College and J.D. and M.B.A. degrees with honors from the University of Chicago. Prior to joining Warburg Pincus, he worked in investment banking at Salomon Brothers in both New York and Hong Kong. Mr. Kagan currently also serves on the boards of directors of the following public companies: Laredo Petroleum, MEG Energy Corp. and Targa Resources Corp., as well as the boards of several private companies. Mr. Kagan also serves on the Board of Directors of the general partner of Antero Midstream Partners LP. In addition, he is a director of Resources for the Future and a trustee of Milton Academy.

Mr. Kagan has significant experience with energy companies and investments and broad knowledge of the oil and gas industry. We believe his background and skill set make Mr. Kagan well suited to serve as a member of our board of directors.

W. Howard Keenan, Jr. has served as a director since 2004. Mr. Keenan has over thirty-five years of experience in the financial and energy businesses. Since 1997, he has been a Member of Yorktown Partners LLC, a private investment manager focused on the energy industry. Mr. Keenan also serves on the Board of Directors of the general partner of Antero Midstream Partners LP. From 1975 to 1997, he was in the Corporate Finance Department of Dillon, Read & Co. Inc. and active in the private equity and energy areas, including the founding of the first Yorktown Partners fund in 1991. He is serving or has served as a director of multiple Yorktown Partners portfolio companies. Mr. Keenan holds an B.A. degree cum laude from Harvard College and an M.B.A. degree from Harvard University.

Mr. Keenan has significant experience with energy companies and investments and broad knowledge of the oil and gas industry. We believe his background and skill set make Mr. Keenan well suited to serve as a member of our board of directors.

Christopher R. Manning has served as a director since 2005. Mr. Manning has been a Partner with Trilantic Capital Partners since its formation and spin out from Lehman Brothers Merchant Banking in April 2009, and is currently a member of its Executive Committee and Chairman of Trilantic Energy Partners. His primary focus is on investments in the energy sector. Mr. Manning joined Lehman Brothers Merchant Banking in 2000 and was concurrently the Head of Lehman Brothers' Investment Management Division, including both the Asset Management and Private Equity businesses, in Asia Pacific from 2006 to 2008. He was also a member of the Global Investment Management Division Executive Committee and the Private Equity Division Operating Committee. Prior to Lehman Brothers, Mr. Manning was the chief financial officer of The Wing Group, a developer of international power projects. Prior

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to The Wing Group, he was in the investment banking department of Kidder, Peabody & Co., where he worked on M&A and corporate finance transactions in the energy sector. Mr. Manning currently serves on the boards of The Cross Group, Enduring Resources, LLC, Templar Energy LLC, Trail Ridge Energy Partners II LLC, Velvet Energy, Ltd., and Ward Energy Partners. Mr. Manning also serves on the Board of Directors of the general partner of Antero Midstream Partners LP. Mr. Manning was previously Chairman of the Board of LB Pacific and TLP Energy and a director of Mediterranean Resources and VantaCore Partners. Mr. Manning holds an M.B.A. from The Wharton School of the University of Pennsylvania and a B.B.A. from the University of Texas at Austin.

Mr. Manning has significant experience with energy companies and investments and broad knowledge of the oil and gas industry. We believe his background and skill set make Mr. Manning well suited to serve as a member of our board of directors.

Richard W. Connor has served as a director and chairman of our audit committee since September 1, 2013. Prior to his retirement in September 2009, Mr. Connor was an audit partner with KPMG LLP, or KPMG, where he principally served publicly traded clients in the energy, mining, telecommunications, and media industries for 38 years. Mr. Connor was elected to the partnership in 1980 and was appointed to KPMG's SEC Reviewing Partners Committee in 1987 where he served until his retirement. From 1996 to September 2008, he served as the Managing Partner of KPMG's Denver office. Mr. Connor earned his B.S. degree in accounting from the University of Colorado. Mr. Connor is a member of the Board of Directors of Zayo Group LLC, a provider of bandwidth infrastructure and colocation services. Mr. Connor is also a director of Centerra Gold, Inc. (TSX: CG.T), a Toronto based gold mining company listed on the Toronto Stock Exchange. Mr. Connor also serves as a director and chairman of the audit committee of the general partner of Antero Midstream Partners LP.

Mr. Connor has experience in technical accounting and auditing matters, knowledge of SEC filing requirements and experience with a variety of energy clients. We believe his background and skill set make Mr. Connor well suited to serve as a member of our board of directors and as chairman of our audit committee.

Robert J. Clark has served as a director, member of the audit committee and Chairman of the compensation committee since our initial public offering in October 2013. Mr. Clark has been Chairman and Chief Executive Officer of 3 Bear Energy, LLC, a midstream energy company with operations in the Rocky Mountains, since its formation in March 2013. Prior to the formation of 3 Bear Energy LLC, Mr. Clark formed, operated and subsequently sold Bear Tracker Energy in February 2013 (to Summit Midstream Partners, LP), a portion of Bear Cub Energy in April 2007 (to Regency Energy Partners, L.P.) and the remaining portion in December 2008 (to GeoPetro Resources Company) and Bear Paw Energy in 2001 (to ONEOK Partners, L.P., formerly Northern Border Partners, L.P.). Mr. Clark was President of SOCO Gas Systems, Inc. and Vice President Gas Management for Snyder Oil Corporation from 1988 to 1995. Mr. Clark served as Vice President Gas Gathering, Processing and Marketing of Ladd Petroleum Corporation, an affiliate of General Electric, from 1985 to 1988. Prior to 1985, Mr. Clark held various management positions with NICOR, Inc. Mr. Clark received his Bachelor of Science degree from Bradley University and his Master's Degree in Business Administration from Northern Illinois University. Mr. Clark is a member of the board of trustees of Bradley University and serves on the board of trustees of Children's Hospital Colorado Foundation.

Mr. Clark has significant experience with energy companies, with over 45 years of experience in the industry. We believe his background and skill set make Mr. Clark well suited to serve as a member of our board of directors.

Benjamin A. Hardesty has served as a director, chairman of our nominating and governance committees, and member of our compensation committee since our initial public offering in October 2013. He has also served as a member of our audit committee since September 2014. Mr. Hardesty has been the owner of Alta Energy LLC, a consulting business focused on oil and natural gas in the Appalachian Basin and onshore United States since May 2010. Mr. Hardesty retired as president of Dominion E&P, Inc., a subsidiary of Dominion Resources Inc. (NYSE:

D) engaged in the exploration and production of natural gas in North America, a position he had held since September 2007. Mr. Hardesty joined Dominion in 1995 and served as president of Dominion Appalachian Development, Inc. until 2000 and general manager and vice president—Northeast Gas Basins until 2007. Mr. Hardesty was a member of the board of directors of KLX, Inc. (NASDAQ:KLXI). From 1978 to 1995, Mr. Hardesty held operating and executive positions with Development Drilling Corp. and Stonewall Gas Company. Mr. Hardesty received his Bachelor of Science degree from West Virginia University and his Master of Science degree from The George Washington University. Mr. Hardesty served as an active duty officer in the U.S. Army Security Agency.

Mr. Hardesty is a director emeritus and past president of the West Virginia Oil & Natural Gas Association and past president of the Independent Oil & Gas Association of West Virginia. Additionally, Mr. Hardesty is a trustee and past chairman of the Nature Conservancy of West Virginia and a member of the board of directors of the West Virginia Chamber of Commerce. Mr. Hardesty serves as a member of the Visiting Committee of the Petroleum Natural Gas Engineering Department of the Statler College of Engineering and Mineral Resources at West Virginia University.

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Mr. Hardesty has significant experience in the natural gas industry, including in our areas of operation. We believe his background and skill set make Mr. Hardesty well suited to serve as a member of our board of directors.

James R. Levy has served as a director and member of our audit and compensation committees since our initial public offering in October 2013. Mr. Levy joined Warburg Pincus in 2006 and focuses on investments in the energy industry. Mr. Levy is a Partner of Warburg Pincus & Co. and a Managing Director of Warburg Pincus LLC. Prior to joining Warburg Pincus, Mr. Levy worked as a private equity investor at Kohlberg & Company and in M&A advisory at Wasserstein Perella & Co. Mr. Levy currently serves on the board of directors of Laredo Petroleum and several private companies. He is a former director of Broad Oak Energy. Mr. Levy received a Bachelor of Arts degree from Yale University.

Mr. Levy has significant experience with energy companies and investments and broad knowledge of the oil and gas industry. We believe his background and skill set make Mr. Levy well suited to serve as a member of our board of directors.

Item 11. Executive Compensation

Pursuant to General Instruction G(3) to Form 10 K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2015 Annual Meeting of Stockholders.

Item 12. Security Ownership of Certain Beneficial Owners and Management

Pursuant to General Instruction G(3) to Form 10 K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2015 Annual Meeting of Stockholders.

Item 13. Certain Relationships and Related Transactions and Director Independence

Pursuant to General Instruction G(3) to Form 10 K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2015 Annual Meeting of Stockholders.

Item 14. Principal Accountant Fees and Services

Pursuant to General Instruction G(3) to Form 10 K, we incorporate by reference into this Item the information to be disclosed in our definitive proxy statement for our 2015 Annual Meeting of Stockholders.

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PART IV

Item 15. Exhibits and Financial Statement Schedules

(a)(1) and (a)(2) Financial Statements and Financial Statement Schedules

The consolidated financial statements are listed on the Index to Financial Statements to this report beginning on page F 1.

(a)(3) Exhibits.

Exhibit Number	Description of Exhibit
2.1	Purchase and Sale Agreement, dated June 1, 2012, between Antero Resources Corporation and Vanguard Permian, LLC (incorporated by reference to Exhibit 2.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on July 5, 2012)
2.2	Purchase and Sale Agreement by and among Antero Resources Piceance LLC, Antero Resources Pipeline LLC and Ursa Resources Group II LLC, dated as of November 1, 2012 (incorporated by reference to Exhibit 2.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on November 6, 2012).
3.1	Amended and Restated Certificate of Incorporation of Antero Resources Corporation (incorporated by reference to Exhibit 3.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
3.2	Amended and Restated Bylaws of Antero Resources Corporation (incorporated by reference to Exhibit 3.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
4.1	Indenture related to the 7.25% Senior Notes due 2019, dated as of August 1, 2011, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on August 1, 2011).
4.2	Form of 7.25% Senior Note due 2019 (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K (Commission File No. 333-164876) filed on August 1, 2011).
4.3	First Supplemental Indenture related to the 7.25% Senior Notes due 2019, dated as of November 12, 2012, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee trustee (incorporated by reference to Exhibit 4.3 to Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 27, 2014).
4.4	Second Supplemental Indenture related to the 7.25% Senior Notes due 2019, dated as of October 16, 2013, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.4 to Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 27, 2014).
4.5	Third Supplemental Indenture related to the 7.25% Senior Notes due 2019, dated as of October 21, 2013, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.5 to Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 27, 2014).
4.6	Fourth Supplemental Indenture related to the 7.25% Senior Notes due 2019, dated as of December 31, 2013, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.6 to Annual

	Report on Form 10-K (Commission File No. 001-36120) filed on February 27, 2014).
4.7	Fifth Supplemental Indenture related to the 7.25% Senior Notes due 2019, dated as of March 18, 2014, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on May 7, 2014).

4.8 Indenture related to the 6.0% Senior Notes due 2020, dated as of November 19, 2012, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on November 20, 2012).

4.9 Form of 6.0% Senior Note due 2020 (incorporated by reference to Exhibit 4.2 to Current Report on Form 8- K (Commission File No. 333-164876) filed on November 20, 2012).

4.10 First Supplemental Indenture related to the 6.0% Senior Notes due 2020, dated October 16, 2013, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.10 to Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 27, 2014).

4.11 Second Supplemental Indenture related to the 6.0% Senior Notes due 2020, dated October 21, 2013, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.11 to Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 27, 2014).

4.12 Third Supplemental Indenture related to the 6.0% Senior Notes due 2020, dated December 31, 2013, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.12 to Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 27, 2014).

4.13 Fourth Supplemental Indenture related to the 6.0% Senior Notes due 2020, dated March 18, 2014, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.2 to Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on May 7, 2014).

4.14 Registration Rights Agreement related to the 6.0% Senior Notes due 2020, dated as of November 19, 2012, by and among Antero Resources LLC and the other parties named therein and Wells Fargo Securities as representative for the initial purchasers named therein (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K (Commission File No. 333-164876) filed on November 20, 2012).

4.15 Registration Rights Agreement related to the 6.0% Senior Notes due 2020, dated as of February 4, 2013, by and among Antero Resources Finance Corporation, the several guarantors named therein and J.P. Morgan Securities LLC as representative of the initial purchasers named therein (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K (Commission File No. 333-164876) filed on February 4, 2013).

4.16 Indenture related to the 5.375% Senior Notes due 2021, dated as of November 5, 2013, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on November 7, 2013).

4.17 Form of 5.375% Senior Note due 2021 (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on November 7, 2013).

4.18 First Supplemental Indenture related to the 5.375% Senior Notes due 2021, dated as of December 31, 2013, by and among Antero Resources Finance Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.17 to Annual Report on Form 10-K (Commission File No. 001-36120) filed on February 27, 2014).

4.19 Second Supplemental Indenture related to the 5.375% Senior Notes due 2021, dated as of March 18, 2014, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on May 7, 2014).

4.20 Registration Rights Agreement related to the 5.375% Senior Notes due 2021, dated as of November 5, 2013, by and among Antero Resources Finance Corporation, the several guarantors named therein and J.P. Morgan Securities LLC as representative of the initial purchasers named therein (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K (Commission File No. 001-36120) filed on November 7, 2013).

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4.21	Registration Rights Agreement, dated as of October 16, 2013, by and among Antero Resources Corporation and the owners of the membership interests in Antero Resources Investment LLC (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
4.22	Indenture related to the 5.125% Senior Notes due 2022, dated as of May 6, 2014, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).
4.23	Form of 5.125% Senior Note due 2022 (incorporated by reference to Exhibit 4.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).
4.24	First Supplemental Indenture related to the 5.125% Senior Notes due 2022, dated as of November 24, 2014, by and among Antero Resources Corporation, the several guarantors named therein and Wells Fargo Bank, National Association, as trustee (incorporated by reference to Exhibit 4.3 to Antero Resource Corporation's Registration Statement on Form S-4 (Commission File No. 333-200605) filed on November 26, 2014).
4.25	Registration Rights Agreement related to the 5.125% Senior Notes due 2022, dated as of May 6, 2014, by and among Antero Resources Corporation and the other parties named therein and J.P. Morgan Securities LLC as representative for the initial purchasers named therein (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).
4.26	Registration Rights Agreement related to the 5.125% Senior Notes due 2022, dated as of September 18, 2014, by and among Antero Resources Corporation and the other parties named therein and J.P. Morgan Securities LLC as representative for the initial purchasers named therein (incorporated by reference to Exhibit 4.3 to Current Report on Form 8-K (Commission File No. 001-36120) filed on September 24, 2014).
10.1	Contribution Agreement, dated as of October 16, 2013, by and between Antero Resources Corporation and Antero Resources Midstream LLC (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
10.2	Form of Indemnification Agreement (incorporated by reference to Exhibit 10.15 to Amendment No. 3 to Antero Resources Corporation's Registration Statement on Form S-1/A (Commission File No. 333-189284), filed on September 24, 2013).
10.3	Agreement and Plan of Merger, dated as of October 1, 2013, by and among Antero Resources Corporation, Antero Resources LLC and Antero Resources Investment LLC (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on October 11, 2013).
10.4	Antero Resources Corporation Long-Term Incentive Plan, effective as of October 1, 2013 (incorporated by reference to Exhibit 4.3 to the Company's Registration Statement on Form S-8 (Commission File No. 001-36120) filed on October 11, 2013).
10.5	Limited Liability Company Agreement of Antero Resources Midstream LLC (incorporated by reference to Exhibit 10.4 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 17, 2013).
10.6	Fourth Amended And Restated Credit Agreement dated as of November 4, 2010 among Antero Resources Corporation, Antero Resources Piceance Corporation, Antero Resources Pipeline Corporation and Antero Resources Appalachian Corporation, as Borrowers, certain subsidiaries of Borrowers, as Guarantors, the Lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, Wells Fargo Bank, N.A., as Syndication Agent, Bank of Scotland Plc, Union Bank, N.A., Credit Agricole Corporate and Investment Bank, BNP Paribas and Deutsche Bank Trust Company Americas, as Co-Documentation Agents and J.P. Morgan Securities LLC and Wells Fargo Securities, LLC, as Joint Lead Arrangers and Joint Bookrunners (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on November 8, 2010).
10.7	First Amendment to the Fourth Amended And Restated Credit Agreement, dated as of May 12, 2011, among Antero Resources Corporation, Antero Resources Piceance Corporation, Antero Resources Pipeline Corporation and Antero Resources Appalachian Corporation, as Borrowers, certain subsidiaries of Borrowers, as Guarantors, the Lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q (Commission File

No. 333-164876) filed on May 16, 2011).

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10.8	Second Amendment to Fourth Amended And Restated Credit Agreement dated as of July 8, 2011 among Antero Resources Corporation, Antero Resources Piceance Corporation, Antero Resources Pipeline Corporation and Antero Resources Appalachian Corporation, as Borrowers, certain subsidiaries of Borrowers, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on July 11, 2011).
10.9	Third Amendment to Fourth Amended And Restated Credit Agreement dated as of October 26, 2011 among Antero Resources Corporation, Antero Resources Piceance Corporation, Antero Resources Pipeline Corporation and Antero Resources Appalachian Corporation, as Borrowers, certain subsidiaries of Borrowers, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on October 28, 2011).
10.10	Fourth Amendment to Fourth Amended And Restated Credit Agreement dated as of May 4, 2012 among Antero Resources Corporation, Antero Resources Piceance Corporation, Antero Resources Pipeline Corporation and Antero Resources Appalachian Corporation, as Borrowers, certain subsidiaries of Borrowers, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on May 7, 2012).
10.11	Fifth Amendment to Fourth Amended and Restated Credit Agreement dated as of October 25, 2012 among Antero Resources Arkoma LLC, Antero Resources Piceance LLC, Antero Resources Pipeline LLC and Antero Resources Appalachian Corporation, as Borrowers, certain subsidiaries of Borrowers, as Guarantors, the Lenders party hereto, and JP Morgan Chase Bank, N.A. as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on October 26, 2012).
10.12	Sixth Amendment to Fourth Amended and Restated Credit Agreement dated as of May 9, 2013 by and among Antero Resources Appalachian Corporation and JPMorgan Chase Bank, N.A., as administrative agent for the lenders, to increase the borrowing base and lender commitments and amend the current ratio covenant under the Fourth Amended and Restated Credit Agreement dated as of November 4, 2010 (incorporated by reference to Exhibit 10.2 to Quarterly Report on Form 10-Q (Commission File No. 333-164876) filed on May 13, 2013).
10.13	Seventh Amendment to Fourth Amended and Restated Credit Agreement dated as of June 27, 2013 by and among Antero Resources Corporation and JPMorgan Chase Bank, N.A., as administrative agent for the lenders, to increase the borrowing base and lender commitments and amend the current ratio covenant under the Fourth Amended and Restated Credit Agreement dated as of November 4, 2010 (incorporated by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q (Commission File No. 333-164876) filed on August 9, 2013).
10.14	Eighth Amendment to Fourth Amended and Restated Credit Agreement dated as of August 29, 2013 by and among Antero Resources Corporation and JPMorgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.23 to Registration Statement on Form S-1/A (Commission File No. 333-189284) filed on August 30, 2013).
10.15	Ninth Amendment to Fourth Amended and Restated Credit Agreement, dated as of October 21, 2013, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 22, 2013).
10.16	Tenth Amendment to Fourth Amended and Restated Credit Agreement, dated as of February 28, 2014, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on May 7, 2014).
10.17	

Eleventh Amendment to Fourth Amended and Restated Credit Agreement, dated as of February 28, 2014, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).

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10.18	Twelfth Amendment to Fourth Amended and Restated Credit Agreement, dated as of July 28, 2014, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on July 31, 2014).
10.19	Thirteenth Amendment to Fourth Amended and Restated Credit Agreement, dated as September 8, 2014, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on September 10, 2014).
10.20	Fourteenth Amendment to Fourth Amended and Restated Credit Agreement, dated as October 16, 2014, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 22, 2014).
10.21	Fifteenth Amendment to Fourth Amended and Restated Credit Agreement, dated as November 10, 2014, among Antero Resources Corporation, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 001-36120) filed on November 17, 2014).
10.22	Credit Agreement, dated as of February 28, 2014, among Antero Resources Midstream Operating LLC, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to Quarterly Report on Form 10-Q (Commission File No. 001-36120) filed on May 7, 2014).
10.23	First Amendment to Credit Agreement, dated as of May 5, 2014, among Antero Resources Midstream Operating LLC, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on May 8, 2014).
10.24	Second Amendment to Credit Agreement, dated as of July 28, 2014, among Antero Resources Midstream Operating LLC, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on July 31, 2014).
10.25	Third Amendment to Credit Agreement, dated as of October 16, 2014, among Antero Resources Midstream Operating LLC, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 001-36120) filed on October 22, 2014).
10.26	Fourth Amendment to Credit Agreement, dated as of November 10, 2014, among Antero Resources Midstream Operating LLC, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.7 to Current Report on Form 8-K (Commission File No. 001-36120) filed on November 17, 2014).
10.27	Fifth Amendment to Credit Agreement, dated as of November 7, 2014, among Antero Resources Midstream Operating LLC, as Borrower, certain subsidiaries of the Borrower, as Guarantors, the Lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (incorporated by reference to Exhibit 10.6 to Current Report on Form 8-K (Commission File No. 001-36120) filed on November 17, 2014).
10.28*	Form of Restricted Stock Unit Grant Notice and Restricted Stock Unit Agreement under the Antero Resources Corporation Long-Term Incentive Plan.
10.29	

Antero Midstream Partners LP Long-Term Incentive Plan (incorporated by reference to Exhibit 4.3 to Midstream Partners' Registration Statement on Form S-8 (Commission File No. 001- 36719) filed on November 12, 2014).

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10.30	Form of Phantom Unit Grant Notice and Phantom Unit Agreement under the Antero Midstream Partners LP Long-Term Incentive Plan (incorporated by reference to Exhibit 4.4 to Midstream Partners' Registration Statement on Form S-8 (Commission File No. 001- 36719) filed on November 12, 2014).
10.31	Form of Restricted Unit Grant Notice and Restricted Unit Agreement under the Antero Midstream Partners LP Long-Term Incentive Plan (incorporated by reference to Exhibit 4.4 to Midstream Partners' Registration Statement on Form S-8 (Commission File No. 001- 36719) filed on November 12, 2014).
10.32	Letter Agreement dated June 29, 2012 by and among Antero Resources Corporation, Antero Resources Piceance Corporation, Antero Resources Pipeline Corporation, Antero Resources Appalachian Corporation and JPMorgan Chase Bank N.A., as administrative agent for the lenders, to reduce the borrowing base and lender commitments under the Fourth Amended and Restated Credit Agreement dated as of November 4, 2010 (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on July 5, 2012).
10.33	Letter Agreement dated November 19, 2012 by and among Antero Resources Arkoma LLC, Antero Resources Piceance LLC, Antero Resources Pipeline LLC, and Antero Resources Appalachian Corporation and JPMorgan Chase Bank N.A., as administrative agent for the lenders, to reduce the borrowing base and lender commitments under the Fourth Amended and Restated Credit Agreement dated as of November 4, 2010 (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on December 10, 2012).
10.34	Letter Agreement dated December 7, 2012 by and among Antero Resources Arkoma LLC, Antero Resources Piceance LLC, Antero Resources Pipeline LLC, and Antero Resources Appalachian Corporation and JPMorgan Chase Bank N.A., as administrative agent for the lenders, to reduce the borrowing base and lender commitments under the Fourth Amended and Restated Credit Agreement dated as of November 4, 2010 (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 333-164876) filed on December 10, 2012).
10.35	Letter Agreement dated February 4, 2013 by and among Antero Resources Arkoma LLC, Antero Resources Piceance LLC, Antero Resources Pipeline LLC, and Antero Resources Appalachian Corporation and JPMorgan Chase Bank, N.A., as administrative agent for the lenders, to reduce the borrowing base and lender commitments under the Fourth Amended and Restated Credit Agreement dated as of November 4, 2010 (incorporated by reference to Exhibit 10.2 to Current Report on Form 8-K (Commission File No. 333-164876) filed on February 4, 2013).
12.1*	Computation of Ratio of Earnings to Fixed Charges.
21.1*	Subsidiaries of Antero Resources Corporation.
23.1*	Consent of KPMG, LLP.
23.2*	Consent of DeGolyer and MacNaughton.
31.1*	Certification of the Company's Chief Executive Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 7241).
31.2*	Certification of the Company's Chief Financial Officer Pursuant to Section 302 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 7241).
32.1*	Certification of the Company's Chief Executive Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 1350).
32.2*	Certification of the Company's Chief Financial Officer Pursuant to Section 906 of the Sarbanes Oxley Act of 2002 (18 U.S.C. Section 1350).
99.1*	Report of DeGolyer and MacNaughton, dated as of January 19, 2015, for proved reserves as of December 31, 2014.
99.2	Report of DeGolyer and MacNaughton, dated as of January 15, 2014, for proved reserves as of December 31, 2013 (incorporated by reference to Exhibit 99.2 to Current Report on Form 8-K (Commission File No. 001- 36120) filed on February 7, 2013).
99.3	Report of DeGolyer and MacNaughton for proved reserves as of December 31, 2012 relating to Marcellus and Upper Devonian resources in the Appalachian Basin (incorporated by reference to Exhibit 99.1 to

Amendment No. 2 to Antero Resources Corporation's Registration Statement on Form S-1/A (Commission File No. 333-189284), filed on August 30, 2013).

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99.4	Report of DeGolyer and MacNaughton for probable reserves as of December 31, 2012 relating to Marcellus and Upper Devonian resources in the Appalachian Basin (incorporated by reference to Exhibit 99.2 to Antero Resources Corporation's Registration Statement on Form S-1/A (Commission File No. 333-189284), filed on August 30, 2013).
99.5	Report of DeGolyer and MacNaughton for possible reserves as of December 31, 2012 relating to Marcellus and Upper Devonian resources in the Appalachian Basin (incorporated by reference to Exhibit 99.3 to Antero Resources Corporation's Registration Statement on Form S-1/A (Commission File No. 333-189284), filed on August 30, 2013).
99.6	Report of DeGolyer and MacNaughton for proved reserves as of December 31, 2012 relating to Utica Shale resources in the Appalachian Basin (incorporated by reference to Exhibit 99.4 to Antero Resources Corporation's Registration Statement on Form S-1/A (Commission File No. 333-189284), filed on August 30, 2013).
99.7	Report of DeGolyer and MacNaughton for probable reserves as of December 31, 2012 relating to Utica Shale resources in the Appalachian Basin (incorporated by reference to Exhibit 99.5 to Antero Resources Corporation's Registration Statement on Form S-1/A (Commission File No. 333-189284), filed on August 30, 2013).
99.8	Report of DeGolyer and MacNaughton for possible reserves as of December 31, 2012 relating to Utica Shale resources in the Appalachian Basin (incorporated by reference to Exhibit 99.6 to Antero Resources Corporation's Registration Statement on Form S-1/A (Commission File No. 333-189284), filed on August 30, 2013).
101*	The following financial information from this Form 10-K of Antero Resources Corporation for the year ended December 31, 2014, formatted in XBRL (eXtensible Business Reporting Language): (i) Consolidated Balance Sheets, (ii) Consolidated Statements of Operations and Comprehensive Income (Loss), (iii) Consolidated Statements of Equity, (iv) Consolidated Statements of Cash Flows, and (v) Notes to the Consolidated Financial Statements, tagged as blocks of text.

The exhibits marked with the asterisk symbol (*) are filed or furnished with this Annual Report on Form 10 K.

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SIGNATURES

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

ANTERO RESOURCES CORPORATION

By: /s/ GLEN C. WARREN, JR.
Glen C. Warren, Jr.
President, Chief Financial Officer and Secretary

Date: February 25, 2015

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Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant in the capacities and on the dates indicated.

Signature	Title	Date
/s/ PAUL M. RADY Paul M. Rady	Chairman of the Board, Director and Chief Executive officer (principal executive officer)	February 25, 2015
/s/ GLEN C. WARREN, JR. Glen C. Warren, Jr.	President, Director, Chief Financial Officer and Secretary (principal financial officer)	February 25, 2015
/s/ K. PHIL YOO K. Phil Yoo	Chief Accounting Officer and Corporate Controller (principal accounting officer)	February 25, 2015
/s/ ROBERT J. CLARK Robert J. Clark	Director	February 25, 2015
/s/ RICHARD W. CONNOR Richard W. Connor	Director	February 25, 2015
/s/ BENJAMIN A. HARDESTY Benjamin A. Hardesty	Director	February 25, 2015
/s/ PETER R. KAGAN Peter R. Kagan	Director	February 25, 2015
/s/ W. HOWARD KEENAN, JR. W. Howard Keenan, Jr.	Director	February 25, 2015
/s/ JAMES R. LEVY James R. Levy	Director	February 25, 2015
/s/ CHRISTOPHER R. MANNING Christopher R. Manning	Director	February 25, 2015

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders

Antero Resources Corporation:

We have audited the accompanying consolidated balance sheets of Antero Resources Corporation and subsidiaries (the Company) as of December 31, 2013 and 2014, and the related consolidated statements of operations and comprehensive income (loss), equity, and cash flows for each of the years in the three year period ended December 31, 2014. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

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

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Antero Resources Corporation and subsidiaries as of December 31, 2013 and 2014, and the results of their operations and their cash flows for each of the years in the three year period ended December 31, 2014, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Antero Resources Corporation's internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 25, 2015 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

Denver, Colorado

February 25, 2015

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders

Antero Resources Corporation:

We have audited Antero Resources Corporation's internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Antero Resources Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting within Item 9A. Controls and Procedures. Our responsibility is to express an opinion on Antero Resources Corporation's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Antero Resources Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Antero Resources Corporation and subsidiaries as of December 31, 2013 and 2014, and the related consolidated statements of operations and comprehensive income (loss), equity, and cash flows for each of the years in the three-year period ended December 31, 2014, and our report dated February 25, 2015 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

Denver, Colorado

February 25, 2015

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ANTERO RESOURCES CORPORATION

Consolidated Balance Sheets

December 31, 2013 and 2014

(In thousands, except share amounts)

	2013	2014
Assets		
Current assets:		
Cash and cash equivalents	$ 17,487	245,979
Accounts receivable, net of allowance for doubtful accounts of $1,251 in 2013 and 2014	30,610	116,203
Accrued revenue	96,825	191,558
Derivative instruments	183,000	692,554
Other	5,642	5,866
Total current assets	333,564	1,252,160
Property and equipment:		
Natural gas properties, at cost (successful efforts method):		
Unproved properties	1,513,136	2,060,936
Proved properties	3,621,672	6,515,221
Fresh water distribution systems	231,684	421,012
Gathering systems and facilities	584,626	1,197,239
Other property and equipment	15,757	37,687
	5,966,875	10,232,095
Less accumulated depletion, depreciation, and amortization	(407,219)	(879,643)
Property and equipment, net	5,559,656	9,352,452
Derivative instruments	677,780	899,997
Other assets, net	42,581	68,886
Total assets	$ 6,613,581	11,573,495
Liabilities and Equity		
Current liabilities:		
Accounts payable	$ 370,640	531,564
Accrued liabilities	77,126	168,614
Revenue distributions payable	96,589	182,352
Deferred income tax liability	69,191	260,373
Derivative instruments	646	—
Other	8,037	12,202
Total current liabilities	622,229	1,155,105
Long-term liabilities:		
Long-term debt	2,078,999	4,362,550
Deferred income tax liability	278,580	534,423

Other long-term liabilities	35,113	47,587
Total liabilities	3,014,921	6,099,665
Commitments and contingencies (notes 11 and 12)		
Equity:		
Stockholders' equity:		
Common stock, $0.01 par value; authorized - 1,000,000,000 shares; issued and outstanding 262,049,659 shares and 262,071,642 shares, respectively	2,620	2,621
Preferred stock, $0.01 par value; authorized - 50,000,000 shares; none issued	—	—
Additional paid-in capital	3,402,180	3,513,725
Accumulated earnings	193,860	867,447
Total stockholders' equity	3,598,660	4,383,793
Noncontrolling interest in consolidated subsidiary	—	1,090,037
Total equity	3,598,660	5,473,830
Total liabilities and equity	$ 6,613,581	11,573,495

See accompanying notes to consolidated financial statements.

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ANTERO RESOURCES CORPORATION

Consolidated Statements of Operations and Comprehensive Income (Loss)

Years Ended December 31, 2012, 2013 and 2014

(In thousands, except share and per share amounts)

	2012	2013	2014
Revenue:			
Natural gas sales	$ 259,743	689,198	1,301,349
Natural gas liquids sales	3,719	111,663	328,323
Oil sales	1,520	20,584	107,080
Gathering, compression, and water distribution	—	—	22,075
Marketing	—	—	53,604
Commodity derivative fair value gains	179,546	491,689	868,201
Gain on sale of gathering system	291,190	—	40,000
Total revenue	735,718	1,313,134	2,720,632
Operating expenses:			
Lease operating	6,243	9,439	29,341
Gathering, compression, processing, and transportation	91,094	218,428	461,413
Production and ad valorem taxes	20,210	50,481	87,918
Marketing	—	—	103,435
Exploration	14,675	22,272	27,893
Impairment of unproved properties	12,070	10,928	15,198
Depletion, depreciation, and amortization	102,026	233,876	477,896
Accretion of asset retirement obligations	101	1,065	1,271
General and administrative (including equity-based compensation expense of $365,280 and $112,252 in 2013 and 2014, respectively)	45,284	425,438	216,533
Total operating expenses	291,703	971,927	1,420,898
Operating income	444,015	341,207	1,299,734
Other expenses:			
Interest	(97,510)	(136,617)	(160,051)
Loss on early extinguishment of debt	—	(42,567)	(20,386)
Total other expenses	(97,510)	(179,184)	(180,437)
Income from continuing operations before income taxes and discontinued operations	346,505	162,023	1,119,297
Provision for income tax expense	(121,229)	(186,210)	(445,672)
Income (loss) from continuing operations	225,276	(24,187)	673,625
Discontinued operations:			
	(510,345)	5,257	2,210

Income (loss) from sale of discontinued operations, net of income tax (expense) benefit of $272,553, $(3,249), and $(1,354) in 2012, 2013, and 2014, respectively			
Net income (loss) and comprehensive income (loss) including noncontrolling interest	(285,069)	(18,930)	675,835
Net income and comprehensive income attributable to noncontrolling interest	—	—	2,248
Net income (loss) and comprehensive income (loss) attributable to Antero Resources Corporation	$ (285,069)	(18,930)	673,587
Earnings (loss) per common share:			
Continuing operations	$ 0.86	(0.09)	2.56
Discontinued operations	(1.95)	0.02	0.01
Total	$ (1.09)	(0.07)	2.57
Earnings (loss) per common share—assuming dilution			
Continuing operations	$ 0.86	(0.09)	2.56
Discontinued operations	(1.95)	0.02	0.01
Total	$ (1.09)	(0.07)	2.57
Weighted average number of shares outstanding:			
Basic	262,049,659	262,049,659	262,053,868
Diluted	262,049,659	262,049,659	262,068,106

See accompanying notes to consolidated financial statements.

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ANTERO RESOURCES CORPORATION

Consolidated Statements of Equity

Years ended December 31, 2012, 2013, and 2014

(In thousands, except share and unit amounts)

	Members' equity	Common Stock	Additional paid-in capital	Accumulated earnings	Noncontrolling interests	Total equity
Balances, December 31, 2011	$ 1,460,947	—	—	497,859	—	1,958,806
Net loss and comprehensive loss	—	—	—	(285,069)	—	(285,069)
Balances, December 31, 2012	1,460,947	—	—	212,790	—	1,673,737
Merger of Antero Resources LLC and Antero Resources Corporation	(1,460,947)	2,244	1,458,703	—	—	—
Issuance of 37,674,659 shares of $0.01 par value common stock in public offering, net of underwriter discounts and offering costs of $79,112	—	376	1,578,197	—	—	1,578,573
Equity-based compensation	—	—	365,280	—	—	365,280
Net loss and comprehensive loss	—	—	—	(18,930)	—	(18,930)
Balances, December 31, 2013	—	2,620	3,402,180	193,860	—	3,598,660
Issuance of common stock upon vesting of equity-based compensation	—	1	(142)	—	—	(141)

awards, net of shares withheld for income taxes						
Equity-based compensation	—	—	111,687	—	565	112,252
Issuance of common units in subsidiary - Antero Midstream Partners LP	—	—	—	—	1,087,224	1,087,224
Net income and comprehensive income	—	—	—	673,587	2,248	675,835
Balances, December 31, 2014	$ —	2,621	3,513,725	867,447	1,090,037	5,473,830

See accompanying notes to consolidated financial statements.

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ANTERO RESOURCES CORPORATION

Consolidated Statements of Cash Flows

Years ended December 31, 2012, 2013, and 2014

(In thousands)

	2012	2013	2014
Cash flows from operating activities:			
Net income (loss) including noncontrolling interest	$ (285,069)	(18,930)	675,835
Adjustment to reconcile net income to net cash provided by operating activities:			
Depletion, depreciation, amortization, and accretion	102,127	234,941	479,167
Impairment of unproved properties	12,070	10,928	15,198
Derivative fair value gain	(179,546)	(491,689)	(868,201)
Cash receipts for settled derivatives	178,491	163,570	135,784
Deferred income tax expense	106,229	190,210	445,672
Gain on sale of assets	(291,190)	—	(40,000)
Equity-based compensation expense	—	365,280	112,252
Loss on early extinguishment of debt	—	42,567	20,386
Loss (gain) on sale of discontinued operations	795,945	(8,506)	(3,564)
Depletion, depreciation, amortization, and impairment of unproved properties—discontinued operations	90,096	—	—
Derivative fair value gains—discontinued operations	(46,358)	—	—
Cash receipts for settled derivatives—discontinued operations	92,166	—	—
Deferred income tax benefit (expense)—discontinued operations	(272,553)	3,249	1,354
Other	4,960	1,173	6,433
Changes in assets and liabilities:			
Accounts receivable	5,511	(9,314)	(45,593)
Accrued revenue	(10,683)	(50,156)	(94,733)
Other current assets	(8,882)	19,543	(2,891)
Accounts payable	(2,117)	1,039	(11,710)
Accrued liabilities	14,790	26,803	85,953
Revenue distributions payable	11,268	50,552	85,763
Other	15,000	3,447	1,016
Net cash provided by operating activities	332,255	534,707	998,121
Cash flows used in investing activities:			
Additions to proved properties	(10,254)	(15,300)	(64,066)
Additions to unproved properties	(687,403)	(440,825)	(777,422)
Drilling and completion costs	(836,350)	(1,615,965)	(2,477,150)
Additions to fresh water distribution systems	(2,801)	(203,790)	(196,675)
Additions to gathering systems and facilities	(142,294)	(389,453)	(558,037)
Additions to other property and equipment	(3,447)	(6,240)	(13,218)
Decrease in notes receivable	4,889	4,555	2,667
Change in other assets	(3,707)	(6,574)	(5,749)

Proceeds from asset sales	1,217,876	—	—
Net cash used in investing activities	(463,491)	(2,673,592)	(4,089,650)
Cash flows from financing activities:			
Issuance of common stock	—	1,578,573	—
Issuance of common units in Antero Midstream Partners LP	—	—	1,087,224
Issuance of senior notes	300,000	1,231,750	1,102,500
Repayment of senior notes	—	(690,000)	(260,000)
Borrowings (repayments) on bank credit facility, net	(148,000)	71,000	1,442,000
Make-whole premium on debt extinguished	—	(33,041)	(17,383)
Payments of deferred financing costs	(5,926)	(20,899)	(31,543)
Other	808	—	(2,777)
Net cash provided by financing activities	146,882	2,137,383	3,320,021
Net increase (decrease) in cash and cash equivalents	15,646	(1,502)	228,492
Cash and cash equivalents, beginning of period	3,343	18,989	17,487
Cash and cash equivalents, end of period	$ 18,989	17,487	245,979
Supplemental disclosure of cash flow information:			
Cash paid during the period for interest	$ 90,122	117,832	163,055
Supplemental disclosure of noncash investing activities:			
Increase in accounts payable for additions to property and equipment	$ 72,881	188,123	181,591

See accompanying notes to consolidated financial statements.

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ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements

Years Ended December 31, 2012, 2013, and 2014

(1) Organization

(a) Business and Organization

Antero Resources Corporation (by itself referred to as "Antero") and its consolidated subsidiaries (collectively referred to as the "Company") are engaged in the exploitation, development, and acquisition of natural gas, natural gas liquids ("NGLs") and oil properties in the Appalachian Basin in West Virginia, Ohio, and Pennsylvania. The Company targets large, repeatable resource plays where horizontal drilling and advanced fracture stimulation technologies provide the means to economically develop and produce natural gas, NGLs, and oil from unconventional formations. The Company has fresh water distribution operations in the Appalachian Basin, as well as gathering and compression operations through its consolidated subsidiary, Antero Midstream Partners LP (referred to as "Antero Midstream"), a publicly-traded limited partnership. During 2012, the Company sold its Oklahoma Arkoma Basin properties and its Colorado Piceance Basin properties. The Company's corporate headquarters are in Denver, Colorado.

(b) Corporate Reorganization and Initial Public Offering

Prior to October 16, 2013, the Company's predecessor, Antero Resources LLC, filed reports with the Securities and Exchange Commission. Antero Resources LLC was formed in October 2009 by members of the Company's management team and its sponsor investors. Antero Resources LLC owned 100% of the outstanding shares of Antero Resources Appalachian Corporation, which was formed in March 2008 and renamed Antero Resources Corporation in June 2013. In connection with an initial public offering ("IPO") completed on October 16, 2013, all of the ownership interests in Antero Resources LLC were exchanged for similar interests in a newly formed limited liability company, Antero Resources Investment LLC ("Antero Investment"), and Antero Resources LLC was merged into Antero Resources Corporation. As a result of this reorganization, Antero Investment owned 100% of the issued and outstanding 224,375,000 shares of common stock of Antero Resources Corporation prior to the IPO.

On October 16, 2013, Antero Resources Corporation issued 37,674,659 additional shares of its common stock at $44.00 per share in the IPO resulting in proceeds to the Company, net of underwriter discounts and expenses of the offering, of approximately $1.6 billion.

(c) Equity-based Compensation Charge in Connection with the Reorganization

In connection with its formation in October 2009, Antero Resources LLC issued profits interests to Antero Resources Employee Holdings LLC ("Employee Holdings"), which is owned solely by certain of the Company's officers and employees. These profits interests provide for the participation in distributions upon liquidation events meeting certain requisite financial return thresholds. In turn, Employee Holdings issued membership interests to certain of the Company's officers and employees. The Employee Holdings interests in Antero Resources LLC were exchanged for similar interests in Antero Investment in connection with the corporate reorganization on October 16, 2013.

The limited liability company agreement of Antero Investment provides a mechanism that demonstrates how the shares of the Company's common stock will be allocated among the members of Antero Investment, including Employee Holdings. As a result of the adoption of the Antero Investment Limited Liability Company agreement, the satisfaction of all performance and service conditions relative to the profits interests awards held by Employee

Holdings in Antero Investment became probable. Accordingly, the Company recognized approximately $449 million of equity-based compensation expense for the vested profits interests through December 31, 2014 and will recognize approximately $37 million over the remaining service period. Equity-based compensation expense for the profits interests during the years ended December 31, 2013 and 2014 was $365.0 million and $83.6 million, respectively. Because consideration for the profits interests awards is deemed given by Antero Investment, the charge to equity-based compensation expense is accounted for as a capital contribution by Antero Investment to the Company and credited to additional paid in capital. All available profits interest awards were made prior to the date of the IPO, and no additional profits interest awards will be made.

(d) Antero Midstream Partners LP

In 2013, the Company formed a subsidiary, Antero Resources Midstream LLC (“ARM”). The Company owned all of the membership interests in ARM other than a special membership interest that was indirectly owned by Antero Investment. On November 10, 2014, ARM was converted to Antero Midstream, a limited partnership, in connection with its initial public offering (the “Antero Midstream IPO”) of 46,000,000 common units representing limited partner interests at a price of $25.00 per common unit. At the closing of the Antero Midstream IPO, the Company contributed its gathering and compression assets to Midstream Operating LLC (referred to as “Midstream Operating”), a wholly-owned subsidiary of Antero Midstream, and the ownership of Midstream Operating was contributed to Antero Midstream. Upon completion of the Antero Midstream IPO, the public owned approximately 30.3% of the outstanding limited partner interests in Antero Midstream, and the Company and its affiliates owned the remaining approximately 69.7% limited partner interests. Antero Resources Midstream Management LLC (referred to as “Midstream Management”), a wholly-owned subsidiary of Antero Investment, owns the general partnership interest in Antero Midstream, which allows Midstream Management to manage the business and affairs of Antero Midstream. Midstream Management also holds the incentive distribution rights in Antero Midstream. Antero Midstream is an unrestricted subsidiary as defined by Antero Resources Corporation’s bank credit facility and senior notes indentures and, as such, Antero Midstream is not a guarantor of Antero’s obligations, and Antero is not a guarantor of Antero Midstream’s obligations.

In conjunction with the closing of the Antero Midstream IPO, the following events occurred:

· Antero and Antero Midstream entered into a services agreement, pursuant to which Antero agreed to provide administrative, management, and other services to Antero Midstream and its subsidiaries in exchange for reimbursemeknt of its direct expenses and an allocation of its indirect expenses attributable to the provision of such services.
· Antero Midstream and its subsidiary entered into a new revolving credit facility (the “Midstream Facility”) with a syndicate of lenders. The Midstream Facility provides for lender commitments of $1.0 billion which may be used to fund the operations of Antero Midstream. The Midstream Facility also provides for a letter of credit sublimit of $150 million. Antero is not a guarantor of the obligations of Antero Midstream under the Midstream Facility.
· Antero and Antero Midstream entered into a 20-year gas gathering and compression agreement. Pursuant to the agreement, Antero agreed to dedicate all of its current and future acreage in West Virginia, Ohio, and Pennsylvania to Antero Midstream for gathering and compression services, so long as production is not otherwise subject to a pre-existing dedication to third-party gathering systems. Antero Midstream is entitled to receive specific fees for the services it provides to Antero, each of which are subject to price adjustments based on the consumer price index. In addition, if Antero acquires any gathering facilities, it is required to offer such gathering facilities to Antero Midstream at Antero’s cost. Antero Midstream also has an option to gather and compress natural gas produced by Antero on any acreage it acquires in the future outside of West Virginia, Ohio, and Pennsylvania on the same terms and conditions.
· Antero Midstream granted a total of 2,361,440 phantom units to employees and officers of Antero. Additionally, Antero Midstream granted a total of 20,000 restricted units to its directors. See additional information relating to the recognition of expense under these awards in note 7.

The gross proceeds to Antero Midstream from its IPO were approximately $1.2 billion. After subtracting underwriting discounts and offering expenses of approximately $63 million, net proceeds received by Antero Midstream from the sale of 46,000,000 Common Units were approximately $1.1 billion. Antero Midstream used approximately $843 million of the net proceeds to repay assumed indebtedness from Antero and reimburse Antero for certain capital expenditures incurred. Antero Midstream retained $250 million of the net proceeds for general partnership purposes.

(2) Summary of Significant Accounting Policies

(a) Basis of Presentation

The accompanying consolidated financial statements of the Company have been prepared in accordance with accounting principles generally accepted in the United States ("GAAP"). In the opinion of management, the accompanying consolidated financial statements include all adjustments (consisting of normal and recurring accruals) considered necessary to present fairly the Company's financial position as of December 31, 2013 and 2014, and the results of its operations and its cash flows for the years ended December 31, 2012, 2013, and 2014. The Company has no items of other comprehensive income or loss; therefore, its net income or loss is identical to its comprehensive income or loss.

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ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014

As of the date these financial statements were filed with the Securities and Exchange Commission, the Company completed its evaluation of potential subsequent events for disclosure and no items requiring disclosure were identified, except for the increase in commitments under the revolving credit facility described in note 5(a) to the consolidated financial statements.

(b) Principles of Consolidation

The accompanying consolidated financial statements include the accounts of Antero Resources Corporation, its wholly owned subsidiaries, and any entities in which the Company owns a controlling interest. All significant intercompany accounts and transactions have been eliminated in the Company's consolidated financial statements. Noncontrolling interest in the Company's consolidated financial statements represents interest in Antero Midstream which is owned by third-party individuals or entities. An affiliate of the Company owns the general partner interest in Antero Midstream, as well as all of the incentive distribution rights. Noncontrolling interest is included as a component of stockholders' equity in the Company's consolidated balance sheets.

(c) Use of Estimates

The preparation of consolidated financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported assets and liabilities and disclosure of contingent assets and liabilities at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the reporting period. Changes in facts and circumstances or discovery of new information may result in revised estimates, and actual results could differ from those estimates.

The Company's consolidated financial statements are based on a number of significant estimates including estimates of gas and oil reserve quantities, which are the basis for the calculation of depreciation, depletion, amortization, and impairment of oil and gas properties. Reserve estimates by their nature are inherently imprecise. Other items in the Company's consolidated financial statements which involve the use of significant estimates include derivative assets and liabilities, accrued revenue, deferred income taxes, asset retirement obligations, stock based compensation, and commitments and contingencies.

(d) Risks and Uncertainties

Historically, the market for natural gas, NGLs, and oil has experienced significant price fluctuations. Price fluctuations can result from variations in weather, levels of production in the region, availability of transportation capacity to other regions of the country, and various other factors. Increases or decreases in the prices the Company receives for its production could have a significant impact on the Company's future results of operations.

(e) Cash and Cash Equivalents

The Company considers all liquid investments purchased with an initial maturity of three months or less to be cash equivalents. The carrying value of cash and cash equivalents approximates fair value due to the short term nature of these instruments.

(f) Oil and Gas Properties

The Company accounts for its natural gas and crude oil exploration and development activities under the successful efforts method of accounting. Under the successful efforts method, the costs incurred to acquire, drill, and complete productive wells, development wells, and undeveloped leases are capitalized. Oil and gas lease acquisition costs are also capitalized. Exploration costs, including personnel and other internal costs, geological and geophysical expenses, delay rentals for gas and oil leases, and costs associated with unsuccessful lease acquisitions are charged to expense as incurred. Exploratory drilling costs are initially capitalized, but charged to expense if and when the Company determines that the well does not contain reserves in commercially viable quantities. The Company incurred no such charges during the years ended December 31, 2012, 2013, and 2014. The Company reviews exploration costs related to wells in progress at the end of each quarter and makes a determination, based on known results of drilling at that time, whether the costs should continue to be capitalized pending further well testing and results, or charged to expense. The sale of a partial interest in a proved property is accounted for as a cost recovery, and no gain or loss is recognized as long as this treatment does not significantly affect the units of production amortization rate. A gain or loss is recognized for all other sales of producing properties.

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Unproved properties with significant acquisition costs are assessed for impairment on a property by property basis, and any impairment in value is charged to expense. Impairment is assessed based on remaining lease terms, drilling results, reservoir performance, commodity price outlooks, and future plans to develop acreage. Other unproved properties are assessed for impairment on an aggregate basis. Unproved properties and the related costs are transferred to proved properties when reserves are discovered on or otherwise attributed to the property. Proceeds from sales of partial interests in unproved properties are accounted for as a recovery of cost without recognition of any gain or loss until the cost has been recovered. Impairment of unproved properties for leases which have expired, or are expected to expire, was $12.1 million, $10.9 million, and $15.2 million for the years ended December 31, 2012, 2013, and 2014, respectively.

The Company reviews its proved oil and gas properties for impairment whenever events and circumstances indicate that the carrying value of the properties may not be recoverable. When determining whether impairment has occurred, the Company estimates the expected future cash flows of its oil and gas properties and compares such future cash flows to the carrying amount of the properties to determine if the carrying amount is recoverable. If the carrying amount exceeds the estimated undiscounted future cash flows, the Company reduces the carrying amount of the properties to their estimated fair value. The factors used to determine fair value include estimates of proved reserves, future commodity prices, future production estimates, anticipated capital expenditures, and a commensurate discount rate. There were no impairments of proved natural gas properties during the years ended December 31, 2012, 2013, and 2014.

At December 31, 2014, the Company did not have significant capitalized costs related to exploratory wells in progress which were pending determination of proved reserves. The Company had no significant costs which have been deferred for longer than one year pending determination proved reserves at December 31, 2014.

The provision for depreciation, depletion, and amortization of oil and gas properties is calculated on a geological reservoir basis using the units of production method. Depreciation, depletion, and amortization expense for oil and gas properties was $181.7 million, $219.8 million, and $418.7 million for the years ended December 31, 2012, 2013, and 2014, respectively.

(g) Gathering Pipelines, Compressor Stations, and Fresh Water Distribution Systems

Expenditures for construction, installation, major additions, and improvements to property, plant, and equipment that is not directly related to production are capitalized, whereas minor replacements, maintenance, and repairs are expensed as incurred. Gathering pipelines and compressor stations are depreciated using the straight line method over their estimated useful lives of 20 years. Fresh water distribution systems are depreciated over useful lives of 5 to 20 years. Depreciation expense for gathering pipelines, compressor stations, and fresh water distribution systems was $7.4 million, $11.9 million, and $53.2 million for the years ended December 31, 2012, 2013, and 2014, respectively. A gain or loss is recognized upon the sale or disposal of property and equipment.

(h) Impairment of Long Lived Assets Other than Oil and Gas Properties

The Company evaluates its long lived assets other than natural gas properties for impairment when events or changes in circumstances indicate that the related carrying values of the assets may not be recoverable. Generally, the basis for making such assessments is undiscounted future cash flow projections for the unit being assessed. If the carrying values of the assets are deemed not recoverable, the carrying values are reduced to the estimated fair value, which is based on discounted future cash flows or other techniques, as appropriate. No impairments for such assets have been recorded through December 31, 2014.

(i) Other Property and Equipment

Other property and equipment assets are depreciated using the straight line method over their estimated useful lives, which range from 2 to 20 years. Depreciation expense for other property and equipment was $1.7 million, $2.2 million, and $5.9 million for the years ended December 31, 2012, 2013, and 2014, respectively. A gain or loss is recognized upon the sale or disposal of property and equipment.

(j) Deferred Financing Costs

Deferred financing costs represent loan origination fees, initial purchasers' discounts, and other borrowing costs and are included in noncurrent other assets on the consolidated balance sheets. These costs are amortized over the term of the related debt instrument using the effective interest method. The Company charges expense for deferred financing costs remaining for debt

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014

facilities that have been retired prior to their maturity date. At December 31, 2014, the Company had $52 million of unamortized deferred financing costs included in other long term assets. The amounts amortized and the write off of previously deferred debt issuance costs were $5.2 million, $15.8 million, and $11.0 million for the years ended December 31, 2012, 2013, and 2014, respectively.

(k) Derivative Financial Instruments

In order to manage its exposure to natural gas, NGLs, and oil price volatility, the Company enters into derivative transactions from time to time, including commodity swap agreements, basis swap agreements, collar agreements, and other similar agreements relating to the price risk associated with a portion of its production. To the extent legal right of offset exists with a counterparty, the Company reports derivative assets and liabilities on a net basis. The Company has exposure to credit risk to the extent the counterparty is unable to satisfy its settlement obligation. The Company actively monitors the creditworthiness of counterparties and assesses the impact, if any, on its derivative position.

The Company records derivative instruments on the consolidated balance sheets as either an asset or liability measured at fair value and records changes in the fair value of derivatives in current earnings as they occur. Changes in the fair value of commodity derivatives are classified as revenues on the Company's consolidated statements of operations. The Company's derivatives have not been designated as hedges for accounting purposes.

(l) Asset Retirement Obligations

The Company is obligated to dispose of certain long lived assets upon their abandonment. The Company's asset retirement obligations ("ARO") relate primarily to its obligation to plug and abandon oil and gas wells at the end of their lives. The ARO is recorded at its estimated fair value, measured by reference to the expected future cash outflows required to satisfy the retirement obligation discounted at the Company's credit adjusted, risk free interest rate. Revisions to estimated ARO can result from changes in retirement cost estimates and changes in the estimated timing of abandonment. The fair value of the liability is added to the carrying amount of the associated asset, and this additional carrying amount is depreciated over the life of the asset. The liability is accreted at the end of each period through charges to operating expense. If the obligation is settled for an amount other than the carrying amount of the liability, the Company will recognize a gain or loss on settlement.

The Company delivers natural gas through its gathering assets and delivers water through its water distribution assets and may become obligated by regulatory or other requirements to remove certain facilities or perform other remediation upon retirement of gathering pipelines and compressor stations. However, the Company cannot reasonably predict when production from existing reserves of the fields in which it operates will cease. In the absence of such information, management is not able to make a reasonable estimate of when future dismantlement and removal dates will occur; therefore, the Company has not recorded asset retirement obligations related to its gathering and water distribution assets.

(m) Environmental Liabilities

Environmental expenditures that relate to an existing condition caused by past operations, and that do not contribute to current or future revenue generation, are expensed as incurred. Liabilities are accrued when environmental assessments and/or clean up is probable, and the costs can be reasonably estimated. These liabilities are adjusted as additional information becomes available or circumstances change. As of December 31, 2013 and 2014, the Company did not have a material amount accrued for any environmental liabilities, nor has the Company been cited for any environmental violations that could have a material adverse effect on future capital expenditures or operating results of the Company.

(n) Natural Gas, NGLs, and Oil Revenues

Sales of natural gas, NGLs, and crude oil are recognized when the products are delivered to the purchaser and title transfers to the purchaser. Payment is generally received one month after the sale has occurred. Variances between estimated sales and actual amounts received are recorded in the month payment is received and are not material. The Company recognizes natural gas revenues based on its entitlement share of natural gas that is produced based on its working interests in the properties. The Company records a

ANTERO RESOURCES CORPORATION

Notes to Consolidated Financial Statements (Continued)

Years Ended December 31, 2012, 2013, and 2014

revenue distribution payable to the extent it receives more than its proportionate share of natural gas revenues. At December 31, 2013 and 2014, the Company had no significant imbalance positions.

(o) Concentrations of Credit Risk

The Company's revenues are derived principally from uncollateralized sales to purchasers in the oil and gas industry. The concentration of credit risk in a single industry affects the Company's overall exposure to credit risk because purchasers may be similarly affected by changes in economic and other conditions. The Company has not experienced significant credit losses on its receivables.

The Company's sales to major customers (purchases in excess of 10% of total sales) for the years ended December 31, 2012, 2013, and 2014 are as follows (including sales in discontinued operations):

	2012		2013		2014	
Company A	23	%	30	%	29	%
Company B	13		14		16	