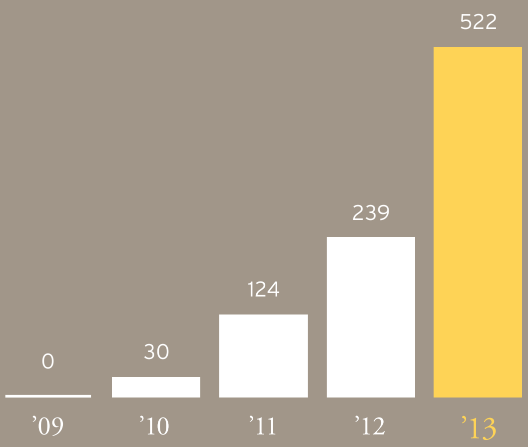
Antero Resources

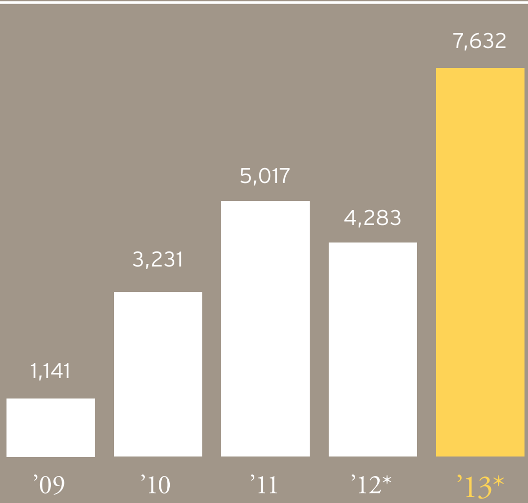
2013

ANNUAL REPORT

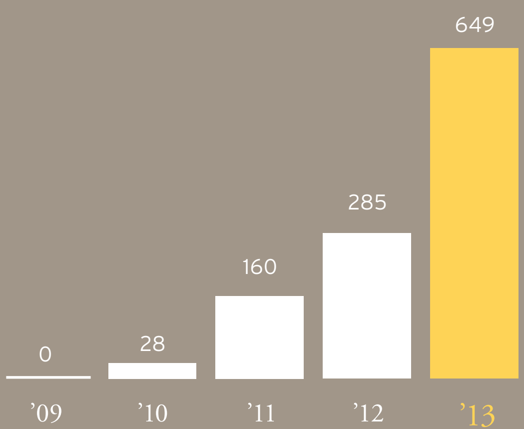
Financial Highlights



PRODUCTION MMcfe/d
Production from continuing operations



RESERVES Bcfe
*Antero reserve estimates as of year-end 2012 and 2013 assume ethane rejection



EBITDAX $MM
EBITDAX from continuing operations

Antero Resources is an independent exploration and production (E&P) company engaged in the exploitation, development, and acquisition of natural gas, NGLs and oil properties located in the Appalachia Basin. Headquartered in Denver, Colorado, we are focused on creating value through the development of our large portfolio of repeatable, low cost, liquids-rich drilling opportunities in two of the premier North American shale plays. We hold approximately 345,000 net acres in the southwestern core of the Marcellus Shale and approximately 105,000 net acres in the core of the Utica Shale.

119%

Production Growth

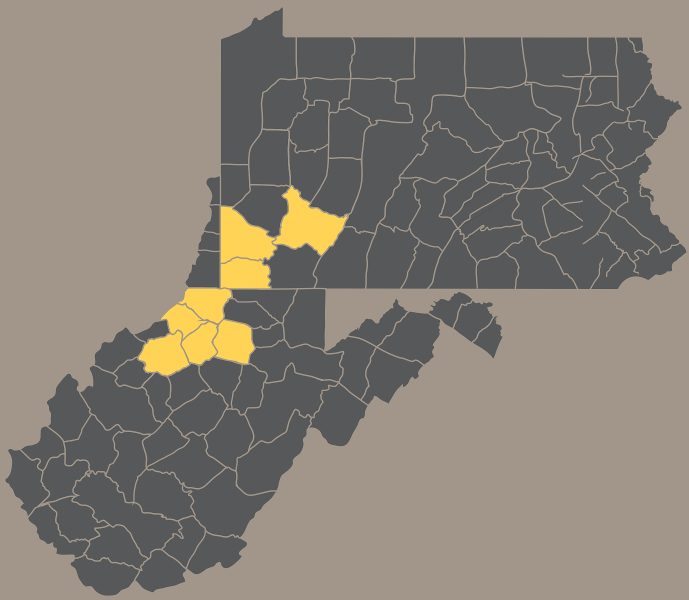
78%

Reserve Growth

128%

EBITDAX Growth

Marcellus Shale



15

DRILLING RIGS

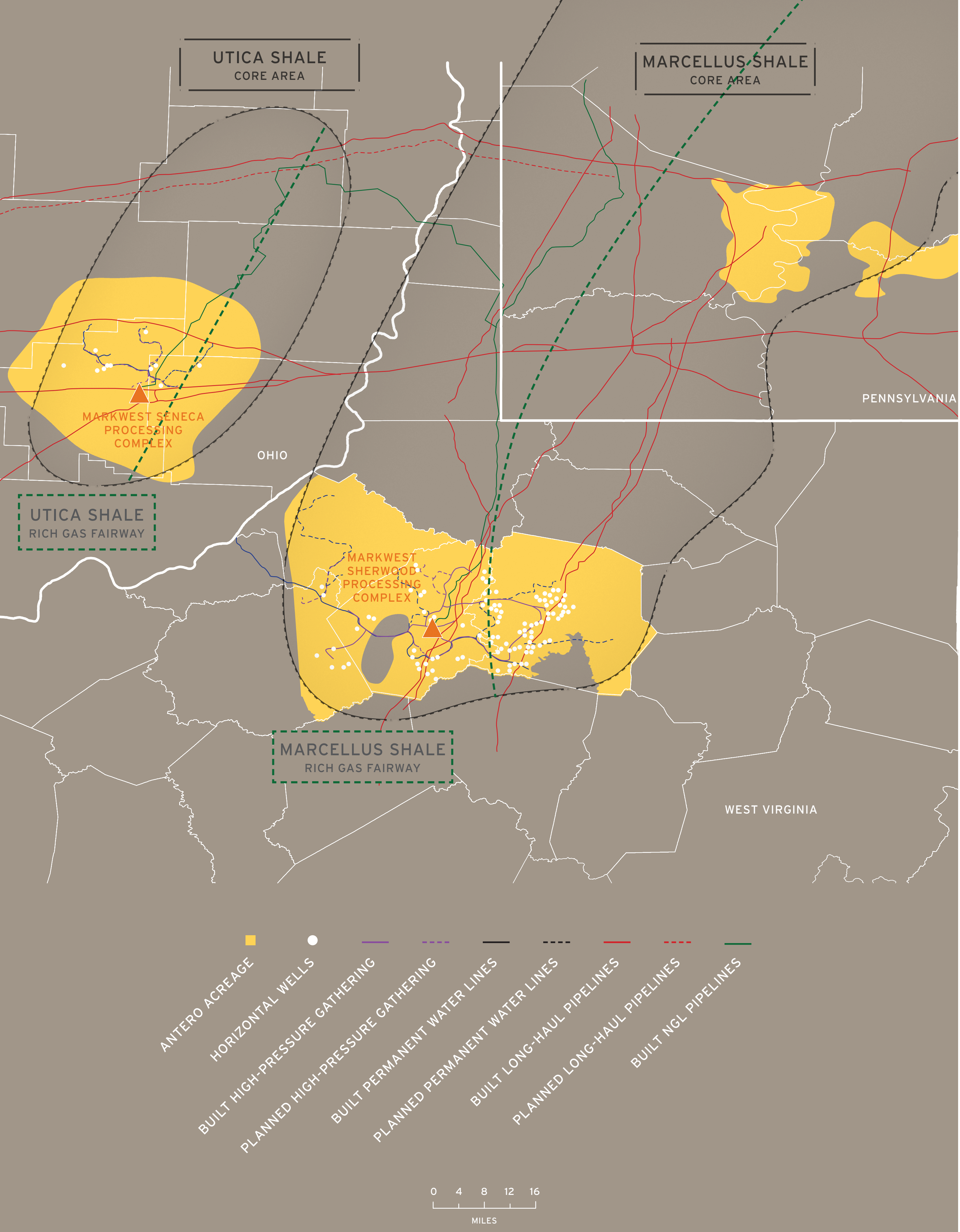
- Production averaged 497 MMcfe/d for 2013 and 624 MMcfe/d in the 4th quarter of 2013
- Proved reserves were 7.3 Tcfe with 3P reserves of 25.0 Tcfe
- 235 wells completed and on-line; 103 wells added in 2013
- Operating 15 drilling rigs
- 92 miles of gathering lines laid by year-end 2013 along with 74 miles of fresh water distribution lines

Utica Shale

5

DRILLING RIGS

- Production averaged 25 MMcfe/d for 2013 and 54 MMcfe/d in the 4th quarter of 2013
- Proved reserves were 362 Bcfe with 3P reserves of 5.8 Tcfe
- 15 wells completed and on-line; 11 wells added in 2013
- Operating 5 drilling rigs
- 49 miles of gathering lines laid by year-end 2013 along with 23 miles of fresh water distribution lines



UTICA SHALE
CORE AREA
MARCELLUS SHALE
CORE AREA
MARKWEST SENECA
PROCESSING
COMPLEX
OHIO
PENNSYLVANIA
UTICA SHALE
RICH GAS FAIRWAY
MARKWEST
SHERWOOD
PROCESSING
COMPLEX
MARCELLUS SHALE
RICH GAS FAIRWAY
WEST VIRGINIA
ANTERO ACREAGE
HORIZONTAL WELLS
BUILT HIGH-PRESSURE GATHERING
PLANNED HIGH-PRESSURE GATHERING
BUILT PERMANENT WATER LINES
PLANNED PERMANENT WATER LINES
BUILT LONG-HAUL PIPELINES
PLANNED LONG-HAUL PIPELINES
BUILT NGL PIPELINES
0 4 8 12 16
MILES

78%

GROWTH IN PROVED RESERVES

119%

PRODUCTION GROWTH RATE

Focused on Growth

DEAR FELLOW SHAREHOLDERS,

The year 2013 was one of transformation and tremendous success for Antero on several fronts. We completed our $1.8 billion initial public equity offering on October 9, 2013, raising $1.6 billion in net proceeds for the Company. We reached the full development phase in our Marcellus Shale project and brought on first production in our Utica Shale project. These events allowed for total organic production and reserve growth of 119 and 78 percent, respectively, while keeping net debt relatively flat—solid measures of success by anyone's standards.

LARGEST INDEPENDENT E&P IPO IN AMERICA'S HISTORY

Several years ago after identifying a large Marcellus resource, we recognized the opportunity to expand our leasehold position and the need to accelerate the outstanding returns our assets were generating. After materially expanding our Marcellus acreage and simultaneously entering the Utica Shale play, the scope of the capital plan associated with the development of more than 400,000 core net acres in the Appalachian Basin led us to the decision to offer a portion of our equity to the public. Despite launching our offering against the headwinds of a government shutdown, we were able to price the offering $2.00 above the offering range and upsize the amount of shares offered by approximately 20 percent. The public purchased $1.8 billion or approximately 15 percent of our common shares. The total proceeds represented the largest independent E&P IPO in U.S. history. We are pleased to report that our share price has increased by over 30 percent since the initial pricing.

FULL DEVELOPMENT OF THE MARCELLUS SHALE

The full development phase of our Marcellus Shale project was marked by the following milestones: 1) we increased our operated rig count to 15, the highest of any company in the play, and 2) our net production averaged approximately 500 MMcfe/d for the year, making Antero one of the basin's top producers. Our rig activity, combined with expanding our core Marcellus leasehold position to 345,000 net acres and achieving exceptional well results, grew our proved and combined proved, probable and possible (3P) reserves to 7 Tcfe and 25 Tcfe, respectively. We also transitioned the majority of our development into the liquids-rich portion of the acreage. We improved our well recoveries by implementing a process we call shorter stage length (SSL) completions and improved our efficiencies by constructing the first phase of our extensive freshwater pipeline distribution system. We and other industry players in the Marcellus discovered that by reducing the length of completion stages and reducing the spacing between perforation clusters, through SSL, we could generate even higher well recoveries. Our freshwater distribution system is dramatically reducing water truck traffic on West Virginia roads within our operating areas as well as reducing our well costs. To accommodate the midstream infrastructure required for this level of growth and activity, we invested almost $600 million in gathering, compression and freshwater distribution assets, contributing significantly to the success of the Marcellus Shale project in 2013.

FIRST PRODUCTION FROM THE UTICA SHALE

Following the buildout of initial gas processing infrastructure, we achieved our first production in the Utica Shale in 2013. We targeted the highest liquids prone area and accumulated, through acquisition and base leasing, a core 105,000 net acre leasehold position in the southern part of the play. Based on our early well results—and the results of other operators in

$1.8B

INITIAL PUBLIC OFFERING

the play—we believe our leasehold position is in the sweet spot of the play. In August we secured access to gas processing and initially placed 11 wells on line, with an average 30-day production rate of approximately 15 MMcfe/d. Our Utica Shale wells exhibit some of the highest production rates of any North American shale play and contain a 30 percent oil and natural gas liquid (NGL) content on average. With initial processing capacity now in place, we increased our rig count to five late in the year. We transitioned to full development early in 2014. Because 2013 was an emerging year for the play, the Utica Shale did not contribute materially to our production or proved reserves during the year. We expect that to change in 2014.

FUTURE READY

Our successes in 2013 heralded Antero's transition into a world-class company and E&P industry leader. We enter 2014 as the most active operator in the Appalachian Basin. For the year we expect to report a peer-leading production growth rate of 75 to 85 percent. We are currently adding approximately 1,000 acres per week to our Marcellus and Utica plays through organic leasing and acquisition efforts, and will continue to consolidate those acreage positions. We also expect to expand our midstream assets and plan to complete an initial public offering of the business as a master limited partnership (MLP).

THE PEOPLE OF ANTERO

The hard work and dedication of our talented employees generated the value creation and momentum this Company exhibited in 2013. The skills and expertise of our people in assembling and executing world-class projects represent Antero's true strength and competitive advantage. We're grateful for the guidance and support of our Board of Directors, including our original equity sponsors. This core group has remained committed to Antero for more than a decade and believed in our business model since inception. We thank you for investing in our Company and look forward to even greater value creation in 2014, and for years to come.

Paul M Rady

Paul M. Rady
Chairman & CEO

Glen C. Warren, Jr.
President & CFO


2013
FORM 10-K
Antero
Resources

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, 2013

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 (State or other jurisdiction of incorporation or organization)	**80-0162034** (IRS Employer Identification No.)
1625 17th St. **Denver Colorado** (Address of principal executive offices)	**80202** (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

As of the last business day of the registrant's most recently completed second fiscal quarter, its common stock was not listed on any domestic exchange or over-the-counter market. The aggregate market value of the voting common stock held by non-affiliates of the registrant as of December 31, 2013, the last business day of the fiscal year, was approximately $2.6 billion.

The registrant had 262,049,659 shares of common stock outstanding as of February 27, 2014.

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 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 statements, 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, including the proposed initial public offering of our midstream business;
- reserves;
- financial strategy, liquidity and capital required for our development program;
- realized natural gas, NGLs and oil prices;
- timing and amount of future production of natural gas, NGLs and oil;
- hedging strategy and results;
- future drilling plans;
- competition and government regulations;
- pending legal or environmental matters;
- marketing of natural gas, natural gas liquids and oil;
- leasehold or business acquisitions;
- costs of developing our properties and conducting our midstream operations;
- 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 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 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.

"*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 equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or NGLs.

"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% 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 net 0.50 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.

"*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, 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 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.

"*Wellbore*." The hole drilled by the bit that is equipped for natural gas production on a completed well. Also called well or borehole.

"*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.

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, 2013, we held approximately 450,000 net acres of rich gas and dry 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, NGL, and oil assets as of the date and for the period indicated.

	At December 31, 2013					Three months ended December 31, 2013
	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	7,226	$5,337	233	345,000	3,068	624
Upper Devonian	44	$ 6	2	—	951	—
Utica Shale	362	$ 655	15	105,000	759	54
Total	7,632	$5,998	250	450,000	4,778	678

(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, 2013, which were $3.65 per Mcf 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.

(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 273 gross (241 net) shallow vertical wells that were acquired in conjunction with leasehold acreage acquisitions.

(4) Net acres allocable to the Upper Devonian are included in the net acres allocated to the Marcellus Shale, because the Upper Devonian and the Marcellus Shale are multi-horizon shale formations 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 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. We have drilled and operated 590 wells from inception through December 31, 2013, with a success rate of approximately 98%. We have a 24-year drilling inventory and have approximately 4,800 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 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 and (ii) midstream operations consisting of gathering, compression and fresh water distribution. All of our operations are conducted in the United States.

2013 Developments and Highlights

Initial Public Offering

On October 16, 2013, we completed the initial public offering (“IPO”) of our common stock. The offering was comprised of an aggregate of 41,083,750 shares of common stock at $44.00 per share, which included 3,409,091 shares of common stock sold by the selling stockholder and 1,949,659 shares of common stock sold by us pursuant to the exercise in full by the underwriters of their option to purchase additional shares of common stock.

The gross proceeds of the IPO were approximately $1.8 billion. After subtracting (i) the net proceeds to the selling stockholders of approximately $143.3 million, (ii) underwriting discounts of approximately $81.4 million (approximately $74.6 million of which were paid by us and $6.8 million of which were paid by the selling stockholder) and (iii) offering expenses of approximately $5.0 million, we received net proceeds of approximately $1.6 billion.

We used approximately $1.4 billion of the net proceeds to repay outstanding borrowings under our revolving credit facility and approximately $150 million to redeem $140 million aggregate principal amount of our outstanding 7.25% senior notes due 2019.

Reserves, Production, and Financial Results

As of December 31, 2013, our estimated proved reserves were 7.6 Tcfe, consisting of 6.8 Tcf of natural gas, 137 MMBbl of NGLs and 10 MMBbl of oil. As of December 31, 2013, 88% of our estimated proved reserves by volume were natural gas, 11% were NGLs, and 1% was oil. Proved developed reserves were 2.0 Tcfe, or 27% of total proved reserves.

For the year ended December 31, 2013, we generated cash flow from operations of $535 million, a net loss of $19 million and EBITDAX of $649 million. Net loss in 2013 included (i) a noncash charge of $365 million for stock compensation, (ii) a noncash tax provision of $186 million, (iii) a charge of $43 million for redemption premiums and the write-off of unamortized deferred financing charges and premium associated with the retirement of $525 million of our 9.375% senior notes due 2017 and $140 million of senior notes due 2019, and (iii) income from discontinued operations of $5 million. In contrast, for the year ended December 31, 2012, we generated cash flow from operations of $332 million, a net loss of $285 million, and EBITDAX of $434 million. The net loss in 2012 included (i) a pre-tax loss of $796 million on the sale of the Arkoma and Piceance Basin properties, (ii) deferred tax benefit related to the loss on the sale of the Arkoma and Piceance properties and discontinued operations of $273 million, (iii) a pre-tax gain on the sale of certain Appalachian gathering systems of $291 million, and (iv) a noncash tax provision related to continuing operations of $121 million. See “Item 6. Selected Financial Data” for a definition of EBITDAX (a non-GAAP measure) and a reconciliation of EBITDAX to net income (loss).

Issuance of $1 Billion 5.375% Senior Notes Due 2021

In November 2013, we issued $1 billion aggregate principal amount of 5.375% senior notes due 2021 at par for net proceeds of approximately $987 million. We used approximately $550 million of the proceeds to retire our 9.375% senior notes due 2017 and the remainder to fund our drilling and development program.

Hedge Position

At December 31, 2013, we had entered into hedging contracts for January 1, 2014 through December 31, 2019 for 1.249 Tcf of our projected natural gas production at a weighted average index price of $4.64 per MMBtu and 1.1 million Bbls of oil at a weighted average price of $96.53 per Bbl. These hedging contracts include contracts for the year ended December 31, 2014 of approximately 223 Bcf of natural gas at a weighted average index price of $4.68 per MMBtu and 1.1 million Bbls of oil at $96.53 per Bbl. We believe this hedge position provides us with protection to future cash flows to support our operations and capital spending plans for 2014.

Credit Facility Availability

Our current borrowing base under our revolving credit facility is $2 billion and lender commitments are $1.5 billion. Lender commitments under our revolving credit facility can be expanded from $1.5 billion to the full $2 billion borrowing base upon bank approval. The borrowing base under our revolving credit facility is redetermined semi-annually and is based on the estimated future cash flows from our proved natural gas, NGL, and oil reserves and our hedge positions. The next redetermination is scheduled to occur in April 2014. Our revolving credit facility provides for a maximum availability of $2.5 billion. At December 31, 2013, we had $320 million of borrowings and letters of credit outstanding under the revolving credit facility and $1.18 billion of available borrowing capacity. Our revolving credit facility matures in May 2016. 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.

2013 Capital Spending and 2014 Capital Budget

For the year ended December 31, 2013, our capital expenditures were approximately $2.7 billion for drilling, leasehold, and from water distribution and gathering systems. Our capital budget for 2014 is $2.6 billion and includes: $1.8 billion for drilling and completion; $600 million for the expansion of midstream facilities, including $200 million for fresh water distribution infrastructure; and $200 million for core leasehold acreage acquisitions. We do not budget for producing property acquisitions. Substantially all of the $1.8 billion allocated for drilling and completion is allocated to our operated drilling in rich gas areas. Approximately 75% of the drilling and completion budget is allocated to the Marcellus Shale, and the remaining 25% is allocated to the Utica Shale. During 2014, we plan to operate an average of 14 drilling rigs in the Marcellus Shale, including three intermediate rigs that drill the vertical section of some horizontal wells to kick-off point, and 4 drilling rigs in the Utica Shale. Consistent with our historical practice, we periodically review our capital expenditures and adjust our budget and its allocation based on liquidity, drilling results, leasehold acquisition opportunities, and commodity prices.

Address, Internet Website and Availability of Public Filings

Our principal executive offices are located at 1625 17th Street, Denver, Colorado 80202 and our telephone number is (303) 357-7310. Our website is located at http://www.anteroresources.com.

We make available our Annual Reports on Form 10-K, our Quarterly Reports on Form 10-Q, and our Current Reports on Form 8-K. These documents are located *www.anteroresources.com* under the "Investors Relations" link.

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 them.

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 Securities and Exchange Commission (the "SEC").

Reserves Presentation

The following table summarizes our estimated proved reserves and related standardized measure and PV-10 at December 31, 2011, 2012 and 2013. Our estimated proved reserves as of December 31, 2012 and 2013 are based on evaluations prepared by our internal reserve engineers, which have been audited by our independent engineers, DeGolyer and MacNaughton ("D&M"). Our estimated proved reserves as of December 31, 2011 were based on evaluations prepared by our internal reserve engineers, which were audited by D&M and Ryder Scott & Company ("Ryder Scott"). 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, 2013 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, 2011 and 2012 were prepared assuming ethane recovery from our production process, while reserves at December 31, 2013 were prepared assuming ethane rejection as a result of the pricing environment shifting to one that favors ethane rejection at December 31, 2013. Reserves at December 31, 2011 include reserves attributable to the Arkoma and Piceance Basin properties which were sold in 2012.

	At December 31,		
	2011	2012	2013
Estimated proved reserves:			
Proved developed reserves:			
Natural gas (Bcf)	718	828	1,818
NGLs (MMBbl)	19	36	33
Oil (MMBbl)	2	1	2
Total equivalent proved developed reserves (Bcfe)	844	1,047	2,022
Proved undeveloped reserves:			
Natural gas (Bcf)	3,213	2,866	4,936
NGLs (MMBbl)	145	167	105
Oil (MMBbl)	15	2	8
Total equivalent proved undeveloped reserves (Bcfe)	4,173	3,882	5,610
Total estimated proved reserves (Bcfe)	5,017	4,929	7,632
Proved developed producing (Bcfe)	804	935	1,771
Proved developed non-producing (Bcfe)	40	112	251
Percent developed	17%	21%	27%
PV-10 (in millions)(1)	$3,445	$1,923	$5,998
Standardized measure (in millions)(1)	$2,470	$1,601	$4,510

(1) PV-10 was prepared using average yearly prices computed using SEC rules, discounted at 10% per annum, without giving effect to taxes. PV-10 is a non-GAAP financial measure.

We believe that the presentation of 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, PV-10 is based on a pricing methodology and discount factors that are consistent for all companies. Because of this, 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 PV-10 amount is the discounted estimated future income tax. 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.

The following table 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, 2011, 2012 and 2013:

	At December 31,		
(In millions, except per Mcf data)	**2011[1]**	**2012[2]**	**2013[3]**
Future net cash flows	$11,470	$7,221	$18,797
Present value of future net cash flows:			
Before income tax (PV-10)	$ 3,445	$1,923	$ 5,998
Income taxes	$ (975)	$ (322)	$(1,488)
After income tax (Standardized measure)	$ 2,470	$1,601	$ 4,510

(1) 12-month average prices used at December 31, 2011 were $3.90 per Mcf for the Arkoma Basin, $3.84 per Mcf for the Piceance Basin and $4.16 per Mcf for the Appalachian Basin.

(2) 12-month average prices used at December 31, 2012 were $2.78 per Mcf 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.

(3) 12-month average prices used at December 31, 2013 were $3.65 per Mcf 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.

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 2011, 2012 and 2013 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 2013

The following table summarizes the changes in our estimated proved reserves during 2013 (in Bcfe):

Proved reserves, December 31, 2012	4,929
Extensions, discoveries, and other additions	3,682
Conversion to ethane rejection	(646)
Price and performance revisions	(142)
Production	(191)
Proved reserves, December 31, 2013	7,632

Extensions, discoveries, and other additions during 2013 of 3,682 Bcfe were added through exploratory and developmental drilling in the Marcellus and Utica Shales. Downward revisions of 646 Bcfe resulted from changing the underlying production assumption used to estimate reserves to ethane rejection at December 31, 2013 from ethane recovery at December 31, 2012. Negative performance revisions of 157 Bcfe were due to the reclassification of 65 wells to the probable category because they are no longer expected to be drilled within five years of initial booking partially offset by improved well performance from shorter stage length completions. Price revisions increased reserves by 15 Bcfe. Our estimated proved reserves as of December 31, 2013 totaled approximately 7.6 Tcfe and increased by 55% over the prior year. Assuming ethane rejection in both years, proved reserves increased by 78% and our proved developed reserves increased year over year by 117% to 2,022 Bcfe at December 31, 2013.

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 2013 (in Bcfe):

Proved undeveloped reserves, December 31, 2012	3,882
Extensions, discoveries, and other additions	2,844
Price and performance revisions	(1,116)
Proved undeveloped reserves, December 31, 2013	5,610

Extensions, discoveries, and other additions during 2013 of 2,844 Bcfe proved undeveloped reserves were added through exploratory and developmental drilling in the Marcellus and Utica Shales. Downward revisions of 1,116 Bcfe are net of a 10 Bcfe increase due to price revisions and are primarily due to changing the underlying production assumption to ethane rejection at December 31, 2013 from ethane recovery at December 31, 2012 as well as the reclassification of certain wells to the probable reserves category in 2013 because they are no longer expected to be drilled within five years of initial booking. 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, 2013, we converted our beginning Appalachian Basin proved undeveloped reserves to proved developed reserves at a rate of 10%. Estimated future development costs relating to the development of our proved undeveloped reserves at December 31, 2013 are approximately $5.3 billion over the next five years, which we expect to finance through cash flow from operations, borrowings under our revolving credit facility, the net proceeds from our initial public offering of our midstream business, 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 focus on 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, 2011, 2012, and 2013 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. Certain of the 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 34 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.

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, 2013. The Company prepares estimates of its probable and possible reserves but is not including 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 dramatically since 2000, natural gas and NGL supplies have also increased significantly as a result of horizontal drilling and fracture stimulation technologies which have 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. 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 gas reserves that may be economically produced and our ability to access capital markets. See "Item 1A. Risk Factors—Natural gas, NGL 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, 2011, 2012 and 2013. 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,		
	2011	2012	2013
Production data:			
Natural gas (Bcf)	45	87	177
NGLs (MBbl)	—	71	2,123
Oil (MBbl)	2	19	226
Total combined production (Bcfe)	45	87	191
Average daily combined production (MMcfe/d)	124	239	522
Average sales prices:			
Natural gas (per Mcf)	$ 4.33	$ 2.99	$ 3.90
NGLs (per Bbl)	$ —	$52.07	$52.61
Oil (per Bbl)	$97.19	$80.34	$91.27
Combined average sales prices before effects of cash settled derivatives (per Mcfe)(1)	$ 4.33	$ 3.03	$ 4.31
Combined average sales prices after effects of cash settled derivatives (per Mcfe)(1)	$ 5.44	$ 5.08	$ 5.17
Average costs per Mcfe:			
Lease operating costs	$ 0.10	$ 0.07	$ 0.05
Gathering, compression, processing, and transportation	$ 0.83	$ 1.04	$ 1.15
Production taxes	$ 0.26	$ 0.23	$ 0.26
Depreciation, depletion, amortization, and accretion	$ 1.24	$ 1.17	$ 1.23
General and administrative(2)	$ 0.74	$ 0.52	$ 0.32

(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.

(2) Does not include noncash stock compensation in 2013.

Discontinued Operations Data—Arkoma and Piceance Basins

The table above does not include the following production or revenue from discontinued operations from the Arkoma and Piceance Basin properties which were sold in 2012:

	Year Ended December 31,		
	2011	2012	2013
Production (combined Bcfe)	44	35	—
Natural gas, NGL and oil production revenues (in millions)	$197	$125	$—

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, 2013, we had a total of 500 gross (460 net) producing wells, averaging a 92% working interest, in the Marcellus Shale. This well count includes 227 gross (219 net) horizontal wells and 273 gross and (241 net) shallow vertical wells that were acquired in conjunction with leasehold acreage acquisitions. In the Utica Shale we had 12 gross (10 net) producing wells at December 31, 2013, averaging an 83% working interest. Our wells are gas wells, many of which also produce oil, condensate and NGLs. Additionally, at December 31, 2013 we had 76 gross wells (69 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, 2013. A majority of our developed acreage is subject to liens securing our revolving credit facility. Approximately 51% of our Marcellus acreage and 20% 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	30,748	30,571	417,484	314,378	448,232	344,949
Utica	5,108	4,024	123,608	101,049	128,716	105,073
Other	—	—	6,609	6,599	6,609	6,599
Total	35,856	34,595	547,701	422,026	583,557	456,621

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

County	Marcellus Gross Acres	Marcellus Net Acres
Doddridge, WV	164,881	120,239
Gilmer, WV	1,649	1,381
Harrison, WV	116,625	101,304
Lewis, WV	89	65
Marion, WV	4,155	3,911
Monongalia, WV	1,835	1,686
Pleasants, WV	1,699	810
Ritchie, WV	65,211	48,544
Tyler, WV	58,530	39,156
Wetzel, WV	5,351	2,822
Fayette, PA	7,364	5,423
Greene, PA	974	454
Washington, PA	12,710	12,235
Westmoreland, PA	7,159	6,919
Total Marcellus Shale	448,232	344,949
	Utica	
Athens, OH	84	84
Belmont, OH	13,367	12,016
Guernsey, OH	10,410	8,674
Harrison, OH	47	47
Monroe, OH	42,212	37,077
Noble, OH	62,596	47,175
Total Utica Shale	128,716	105,073
Total Marcellus and Utica Shale	576,948	450,022

Undeveloped Acreage Expirations

The following table sets forth the number of total gross and net undeveloped acres as of December 31, 2013 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.

	Gross	Net
2014	13,685	7,894
2015	31,217	21,922
2016	39,057	24,732

Drilling Activity

The following table summarizes our drilling activity for the years ended December 31, 2011, 2012 and 2013. 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,					
	2011		2012		2013	
	Gross	Net	Gross	Net	Gross	Net
Marcellus						
Development wells:						
Productive	25	23	48	45	49	48
Dry	—	—	—	—	—	—
Total development wells	25	23	48	45	49	48
Exploratory wells:						
Productive	13	13	15	15	63	62
Dry	—	—	—	—	—	—
Total exploratory wells	13	13	15	15	63	62
Utica						
Development wells:						
Productive	—	—	—	—	3	3
Dry	—	—	—	—	—	—
Total development wells	—	—	—	—	3	3
Exploratory wells:						
Productive	—	—	1	1	13	10
Dry	—	—	—	—	—	—
Total exploratory wells	—	—	1	1	13	10
Arkoma, Piceance, and Other						
Development wells:						
Productive	110	42	58	46	—	—
Dry	—	—	—	—	—	—
Total development wells	110	42	58	46	—	—
Exploratory wells:						
Productive	61	17	6	1	—	—
Dry	—	—	—	—	—	—
Total exploratory wells	61	17	6	1	—	—
Total						
Development wells:						
Productive	135	65	106	91	52	51
Dry	—	—	—	—	—	—
Total development wells	135	65	106	91	52	51
Exploratory wells:						
Productive	74	30	22	17	76	72
Dry	—	—	—	—	—	—
Total exploratory wells	74	30	22	17	76	72

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 such commitments, but may be required to purchase gas from third parties to satisfy shortfalls should they occur.

As of December 31, 2013, our firm sales commitments through 2018 included:

Year Ending December 31,	Volume of Natural Gas (MMcfe/d)
2014	430
2015	420
2016	388
2017	212
2018	200

In addition, 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."

Midstream Operations

Our exploration and development activities are supported by our operated natural gas gathering, compression, processing and transportation assets, as well as by third-party 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. Actively managing these midstream operations allows us to ensure that we can obtain the necessary takeaway and processing capacity for our production and, when necessary or advisable, process our liquids-rich natural gas production to maximize the value that we can obtain for our products.

We maintain a strong commitment 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 have invested a significant amount of capital in building low- and high-pressure gathering lines, compressor stations and 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. We will continue to invest significantly in our midstream infrastructure, as it allows us to optimize our processing and takeaway capacity to support our expected rapid production growth, affords us more control over the direction and planning of our drilling schedule and has historically created significant value for our equity owners. In 2013, we spent approximately $593 million on midstream gas, condensate and fresh water infrastructure. In addition, we believe that our midstream assets may be well suited for a MLP or similar structure. Accordingly, we are pursuing an initial public offering of limited partner interests in an entity that will indirectly own substantially all of our midstream assets. See "Item 1A. Risk Factors—Our ability to complete the proposed initial public offering of our midstream business on the terms currently contemplated, or at all, may result in a reduction in of 2014 capital budget."

Transportation and Takeaway Capacity

Our primary firm transportation commitments include the following:

- We have several firm transportation contracts for volumes that increase from 268,000 MMBtu per day in 2013 to approximately 582,000 MMBtu per day in 2015 on the Columbia Gas Transmission Pipeline. We have firm transportation contracts from the Leach Delivery Point for volumes that increase from 227,000 MMBtu per day in 2013 to 530,000 MMBtu in 2015 on the Columbia Gulf Pipeline. The contracts expire at various dates from 2017 through 2025.

- We have various firm transportation contracts for approximately 353,500 MMBtu per day taking Marcellus natural gas to various other delivery points; these contracts expire in 2022.
- We have a firm transportation contract for 200,000 MMBtu per day on the Rockies Express Pipeline, or REX, beginning in January 2014 to take Utica gas to the Midwestern Gas Transmission pipeline, or Midwestern, which delivers natural gas to Chicago. We have 165,000 MMBtu of firm transportation on the Midwestern pipeline. We can also deliver natural gas into the Midwestern pipeline from our Columbia Gulf capacity through a southern interconnection to the Midwestern. The Rex and Midwestern firm transportation commitments expire in 2021.
- We have a firm transportation contract for approximately 20,000 Bbl per day on the Enterprise Products Partners ATEX pipeline, or ATEX, beginning in the first quarter of 2014 to take ethane from Appalachia to Mont Belvieu, Texas. The ATEX firm transportation commitment expires in 2028. We are not currently utilizing this transportation capacity as the current pricing climate favors ethane rejection over ethane recovery.

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.

We continue to actively identify and evaluate additional processing and takeaway capacity to enhance the value of our Appalachian Basin position.

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 in order to meet quality specifications of long-haul intrastate and interstate pipelines.

NGLs are valuable commodities once removed from the natural gas stream and fractionated into their key components. Fractionation refers to the process by which an NGL stream is separated into individual NGL 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 higher Btu residue gas is greater than the 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 NGL product.

Given the existing commodity price environment and the 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 product stream at current prices. We will elect to recover ethane when ethane prices recover and the value we receive for the ethane is greater than the Btu equivalent residue gas.

Our typical NGL barrel, assuming ethane recovery for 1,225 Btu gas, is composed of 65% ethane, 20% propane, 9% butanes, 6% pentanes-plus. At December 31, 2013, the blended value of this NGL barrel was approximately $18.99/Bbl. When we elect to reject ethane, we sell the ethane as Btu equivalent in our residue gas and our typical NGL barrel for 1,225 Btu gas is composed of approximately 4% ethane, 56% propane, 25% butanes, and 15% pentanes plus. At December 31, 2013, the blended value of an NGL barrel while rejecting ethane was $47.56/Bbl.

As of December 31, 2013, we owned and operated 92 miles of gas gathering pipelines in the Marcellus Shale, and had access to additional low-pressure and high-pressure pipelines owned and operated by Crestwood, Energy Transfer Partners L.P. and Summit Midstream. Additionally, as of December 31, 2013, we owned and operated four compressor stations and utilized twelve 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, 2013, we owned and operated 59 miles of low-pressure, high-pressure and condensate pipelines in the Utica Shale. As of December 31, 2013, we had three third-party compressor stations under construction in the Utica Shale.

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[1]	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	Third Quarter 2014
Sherwood V	200	200	Fourth Quarter 2014
Marcellus Shale Total	1,000	950	
Utica Shale:			
Seneca I	200	200	In service
Seneca II[1]	200	50	In service
Seneca III	200	200	Second Quarter 2014
Seneca IV[2]	200	200	First Quarter 2015
Utica Shale Total	800	600	

(1) We have 50 MMcf/d of interim capacity at the Seneca II processing facility until First Quarter 2015, the Seneca IV in-service date.

(2) Contracted capacity executed January 2014.

Our midstream infrastructure also includes 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, portable 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 will move surface pipelines to service completion operations in concert with our drilling program. As of December 31, 2013, we also have the ability to store a total of 14.9 million barrels of fresh water in 20 impoundments.

The water pipeline systems are expected to deliver a reliable year-round water supply, reduce water handling costs and significantly decrease water truck traffic and associated road damage on state, county and municipal roadways. It is estimated that these water pipeline systems will reduce our well completion costs by $600,000 to $800,000 per well. In 2014, we expect that approximately 90% of our well completions will use these systems. Assuming a 7,000 foot horizontal well lateral, it is estimated that 1,850 water truckload trips per well completion will be eliminated from roadways.

Due to the extensive geographic distribution of our water pipeline systems in both West Virginia and Ohio, we anticipate having the ability to offer water delivery services to neighboring oil and gas producers within and surrounding our operating area, subject to commercial arrangements, in an effort to further reduce water truck traffic.

As of December 31, 2013 in West Virginia, we owned and operated 74 miles of buried fresh water pipelines. Upon full project completion, the buried pipeline system is estimated to be 171 miles long and will extend to the Ohio River and several regional waterways for water sourcing. The water pipeline system will also include an additional 150 miles of purchased, temporary and reusable surface pipeline, 47 centralized water storage facilities equipped with transfer pumps and four other major pumping stations required for transporting water through the buried pipeline system.

As of December 31, 2013 in Ohio, we owned and operated 23 miles of buried fresh water pipelines. Upon project completion, the buried pipeline system is estimated to be 63 miles long and will rely on waterways and lakes within a close proximity to our operating area for water sourcing. The water pipeline system will also include an additional 45 miles of purchased, temporary and reusable surface pipeline and 24 centralized water storage facilities equipped with transfer pumps.

Major Customers

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 Filed Services Inc. represented 23%, 13% and 10% of our total sales, respectively. For the year ended December 31, 2011, sales from our top three customers accounted for 28%, 17%, and 12% of our total sales, respectively. Although a substantial portion of 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, in the case of undeveloped properties, often 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;
- 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 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

Our operations are substantially affected by federal, state and local laws and regulations. In particular, natural gas production and related operations are, or have been, subject to price controls, taxes and numerous other laws and regulations. All of the jurisdictions in which we own or operate producing natural gas and oil properties have statutory provisions regulating the exploration for and production of natural gas and oil, including provisions related to permits for the drilling of wells, bonding requirements 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, and the abandonment of wells. Our operations are also subject to various conservation laws and regulations. These include the regulation of the size of drilling and spacing units or proration units, the number of wells which may be drilled in an area, and the unitization or pooling of crude oil or natural gas wells, as well as regulations that generally prohibit the venting or flaring of natural gas, and impose certain requirements regarding the ratability or fair apportionment of production from fields and individual wells.

Failure to comply with applicable laws and regulations can result in substantial penalties. The regulatory burden on the industry increases the cost of doing business and affects profitability. Although we believe we are in substantial compliance with all applicable laws and regulations, such laws and regulations are frequently amended or reinterpreted. Therefore, we are unable to predict the future costs or impact of compliance. Additional proposals and proceedings that affect the natural gas industry are regularly considered by Congress, the states, the Federal Energy Regulatory Commission (the “FERC”), and the courts. We cannot predict when or whether any such proposals may become effective.

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, current regulatory requirements may change, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered.

Regulation of Production of Natural Gas and Oil

The production of natural gas and oil is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of natural gas and oil properties, the establishment of maximum allowable rates of production from natural gas and oil wells, the regulation of well spacing or density, and plugging and abandonment of wells. The 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.

We own interests in properties located onshore in three U.S. states. These states regulate drilling and operating activities by requiring, among other things, permits for the drilling of wells, maintaining bonding requirements in order to drill or operate wells, and regulating the location of wells, the method of drilling and casing wells, the surface use and restoration of properties upon which wells are drilled and the plugging and abandonment of wells. The laws of these states also govern a number of environmental and conservation matters, including the handling and disposing or discharge of waste materials, the size of drilling and spacing units or proration units and the density of wells that may be drilled, unitization and pooling of oil and gas properties and establishment of maximum rates of production from oil and gas wells. Some states have the power to prorate production to the market demand for oil and gas.

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 and Sales of Natural Gas

The transportation and sale for resale of natural gas in interstate commerce are regulated by 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.

The Domenici Barton Energy Policy Act of 2005, or EP Act 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. The EP Act of 2005 provides FERC with the power to assess civil penalties of up to $1,000,000 per day for violations of the NGA and increased FERC's civil penalty authority under the NGPA to $1,000,000 per violation per day. The civil penalty provisions are applicable to entities that engage in the sale of natural gas for resale in interstate commerce. On January 19, 2006, FERC issued

Order No. 670, a rule implementing the anti-market manipulation provision of the EP Act of 2005, and subsequently denied rehearing. The rules 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 new anti-market manipulation rule does 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 704.

On December 26, 2007, FERC issued Order 704, a final rule on the annual natural gas transaction reporting requirements, as amended by subsequent orders on rehearing. Under Order 704, wholesale buyers and sellers of more than 2.2 million MMBtus of physical natural gas in the previous calendar year, including natural gas gatherers and marketers, are now required to report, on May 1 of each year, aggregate volumes of natural gas purchased or sold at wholesale in the prior calendar year to the extent such transactions utilize, contribute to, or may contribute to the formation of price indices. It is the responsibility of the reporting entity to determine which individual transactions should be reported based on the guidance of Order 704. 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.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting gas to point of sale locations. 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.

Section 1(b) of the NGA exempts natural gas gathering facilities from regulation by 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.

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.

The price at which we sell natural gas is not currently subject to federal rate regulation and, for the most part, is not subject to state regulation. In the past, the federal government has regulated the prices at which natural gas could be sold. Deregulation of wellhead natural gas sales began with the enactment of the NGPA and culminated in adoption of the Natural Gas Wellhead Decontrol Act which removed all price controls affecting wellhead sales of natural gas effective January 1, 1993.

Our sales of natural gas are also subject to requirements under the Commodity Exchange Act, or CEA, and regulations promulgated thereunder by the Commodity Futures Trading Commission, or CFTC. 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.

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, NGL 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 paint wastes, 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.

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. For example, in August 2012, the EPA published 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. With regards to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from three subcategories of fractured and 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 after October 15, 2012. However, the "other" wells must use reduced emission completions, also known as "green completions," with or without combustion devices, after January 1, 2015. These regulations also establish specific new requirements regarding emissions from production-related wet seal and reciprocating compressors, effective October 2012 and from pneumatic controllers and storage vessels, effective October 2013. EPA received numerous requests for reconsideration of these rules from both industry and the environmental community, and court challenges to the rules were also filed. EPA intends to issue revised rules in 2013 that are likely responsive to some of these requests. For example, in April 2013 EPA published a proposed amendment extending compliance dates for certain 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 construction and Title V operating permit reviews for certain large stationary sources that are potential major sources of GHG emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified 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.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations 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 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 published draft permitting guidance in May 2012 addressing the performance of such activities using diesel fuels. In November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing; however, to date, the agency has not yet taken any action to do so.

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. 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, with a first progress report outlining work currently underway by the agency released in December 2012 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 by late 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards at some point in 2014. 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.

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 may 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 approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing of more than 250 species as endangered or threatened under the ESA 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 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 2013, nor do we anticipate that such expenditures will be material in 2014.

Employees

As of December 31, 2013, we had 233 full-time employees, including 20 in executive, finance, treasury and administration, 21 in geology, 84 in production and engineering, 29 in accounting, 63 in land, and 16 in midstream. We also employed approximately 104 contract personnel who assist our full-time employees with specific tasks. 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.

Legal Proceedings

We are party to various 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.

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. 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 management does not expect these matters to have a material adverse effect on our financial condition, results of operations or cash flows.

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. Additional risks not presently known to us or which we currently consider immaterial also may adversely affect our company.

Natural gas, NGL 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, NGL 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;
- 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.

Furthermore, the worldwide financial and credit crisis in recent years has reduced the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide resulting in a slowdown in economic activity and recession in parts of the world. This has reduced worldwide demand for energy and resulted in lower natural gas, NGL and oil prices.

Lower commodity prices will 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 $2.7 billion in 2013. Our board of directors has approved a capital budget for 2014 of $2.6 billion and includes $1.8 billion for drilling and completion; $600 million for expansion of midstream facilities, including $200 million for fresh water distribution infrastructure; and $200 million for core leasehold acreage acquisitions. Our capital budget excludes acquisitions. We expect to fund these capital expenditures with cash generated by operations, reimbursement for pre-contribution capital expenditures from the proposed master limited partnership, borrowings under our revolving credit facility or capital market transactions. 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 reduction in commodity prices from current levels may result in a decrease in our actual capital expenditures, which would negatively impact our ability to grow production. We intend to finance our future capital expenditures primarily through cash flow from operations and through borrowings under our revolving credit facility; 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 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
- our ability to borrow under our revolving credit facility.

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.

Our ability to complete the proposed initial public offering of our midstream business on the terms currently contemplated, or at all, may result in a reduction in our 2014 capital budget.

We are pursuing an initial public offering of limited partnership interests in an entity that will indirectly own substantially all of our midstream assets. Adverse developments in our midstream business may result in our failure to complete the initial public offering, a decrease in the proceeds we receive from the offering or a decrease in the value of the limited partnership interests we retain upon completion of the offering. Potential adverse developments include, but are not limited to:

- any development that adversely affects our exploration, development and production operations, financial conditions or market reputation;
- a shortage of equipment and skilled labor in the Appalachian Basin, which could reduce equipment availability and increase labor and equipment costs associated with our midstream assets;
- a change in the jurisdictional characterization of our midstream assets by federal, state or local agencies or a change in policy by those agencies resulting in increased regulation of such assets;
- increased regulation of hydraulic fracturing that results in reductions or delays in natural gas, NGL and oil production;
- restrictions on our ability to obtain water or changes in wastewater disposal requirements;
- the incurrence by our midstream business of significant liability under, or costs and expenditures to comply with, environmental and worker health and safety regulations; and
- climate change laws and regulations restricting emissions of "greenhouse gases."

In addition, general market conditions, including the market for yield securities, may impact our ability to complete the initial public offering on the terms currently contemplated, or at all. Our inability to complete the initial public offering on the terms currently contemplated, or at all, may result in a reduction in our 2014 capital budget.

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:

- 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;
- declines in natural gas prices;
- limited availability of financing at acceptable terms;
- title problems; and
- limitations in the market for natural gas.

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, our $260 million of 7.25% senior notes due 2019, $525 million of 6.00% senior notes due 2020, and $1 billion of 5.375% notes due 2021 depends on our financial condition and operating performance, which are subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. We may not be able to maintain a level of cash flows from operating activities sufficient to permit us to pay the principal, premium, if any, and interest on our indebtedness, including the 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 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 is currently $2.0 billion, and lender commitments under our revolving credit facility are $1.5 billion. Our next scheduled borrowing base redetermination is expected to occur in April 2014. In the future, we may not be able to access adequate funding under our revolving credit facility as a result of a decrease in our borrowing base due to the issuance of new indebtedness, the outcome of a subsequent semi-annual borrowing base redetermination or an unwillingness or inability on the part of our lending counterparties to meet their funding obligations and the inability of other lenders to provide additional funding to cover the defaulting lender's portion. Declines in commodity prices could result in a determination to lower the borrowing base in the future and, in such a case, we could be required to repay any indebtedness in excess of the redetermined borrowing base. 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 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. As of December 31, 2013, our long-term contractual obligation under these agreements was $3.5 billion. We are obligated to pay fees on minimum volumes to our service providers regardless of actual volume throughput, which could be significant and have a material adverse effect on our results of operations. If these fees on minimum volumes are substantial, we may not be able to generate sufficient cash to cover these obligations, which may require us to reduce or delay our planned investments and capital expenditures or seek alternative means of financing.

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;
- 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. Outstanding borrowings in excess of the borrowing base must be repaid, or we must pledge other natural gas properties as additional collateral after applicable grace periods. We do not currently have any substantial unpledged properties, and we may not have the financial resources in the future to make mandatory principal prepayments required under our revolving credit facility. The borrowing base under our revolving credit facility is currently $2.0 billion and lender commitments are $1.5 billion. Our next scheduled borrowing base redetermination is expected to occur in April 2014.

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, 2013, we had entered into a number of hedge contracts for approximately 1.255 Tcfe of our projected natural gas and oil production through December 31, 2019. We are currently realizing a significant benefit from these hedge positions. For example, for the years ended December 31, 2012 and 2013, we received approximately $271 million and $164 million, respectively, in revenues from cash settled derivatives pursuant to our hedges, which represented approximately 30% and 13%, respectively, of our total revenues (including revenues from discontinued operations) for such periods. Many of the hedge agreements that resulted in these realized gains for the years ended December 31, 2012 and 2013 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. Therefore, we expect that this benefit will decline materially over the life of the hedges, which cover decreasing volumes at declining prices through December 2019. 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, 2012 and 2013, approximately 81% of our estimated future production (including production from discontinued operations) 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, 2013, we had entered into hedging contracts through December 31, 2019 covering a total of approximately 1.255 Tcfe of our projected natural gas and oil production at a weighted average price of $4.61 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.

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, 2013, we had 4,778 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 92% 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 92% 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 49% and 80% 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.

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, 2013, 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 NGL prices.

The Appalachian Basin natural gas and NGL 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 2012 and 2013, we do not believe the existing and expected capacity will be sufficient to keep pace with the increased production caused by accelerated drilling 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, 2013, 73% of our total estimated proved reserves were classified as proved undeveloped. Our approximately 5.6 Tcfe of estimated proved undeveloped reserves will require an estimated $5.3 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.

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.

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, 2013, we had entered into hedging contracts through December 31, 2019 covering a total of approximately 1.255 Tcfe of our projected natural gas and oil production at a weighted average price of $4.61 per Mcfe. 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.

As of December 31, 2013, the estimated fair value of our commodity derivative contracts was approximately $860 million. 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, 2013 includes the following values by bank counterparty: BNP Paribas—$197 million; Credit Suisse—$190 million; Barclays—$147 million; Wells Fargo—$140 million; JP Morgan—$134 million; Citigroup—$34 million; Deutsche Bank—$15 million; and Toronto Dominion Bank—$3 million. The credit ratings of certain of these banks have been downgraded because of the sovereign debt crisis in Europe.

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.

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.

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 ($31 million at December 31, 2013) and the sale of our natural gas production ($97 million in receivables at December 31, 2013), which we market to energy marketing companies, refineries and affiliates. 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, 2013 purchased approximately 30% 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 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. We have responded to all pending orders and are actively 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
- 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 the agreements we will enter into with Antero Midstream.

Pursuant to the gas gathering and compression agreement that we intend to enter into with Antero Midstream, we will dedicate 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 intend to enter into with Antero Midstream, Antero Midstream will have 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 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 and oil markets or delay our production.

Market conditions or the unavailability of satisfactory natural gas and oil transportation arrangements may hinder our access to natural gas 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 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 and oil pipeline or gathering system capacity. In addition, if natural gas or oil quality specifications for the third-party natural gas or oil pipelines with which we connect change so as to restrict our ability to transport natural gas or oil, our access to natural gas 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. 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.

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 EP Act 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 as a natural gas company 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 that are potential major sources of GHG emissions. Facilities required to obtain PSD permits for their GHG emissions also will be required to meet "best available control technology" standards that will be established by the states or, in some cases, by the EPA on a case-by-case basis. These EPA rulemakings could adversely affect our operations and restrict or delay our ability to obtain air permits for new or modified 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. While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce GHG emissions at the federal level in recent years. In the absence of such federal climate legislation, a number of state and regional efforts have emerged that are aimed at tracking and/or reducing GHG emissions by means of cap and trade programs that typically require major sources of GHG emissions, such as electric power plants, to acquire and surrender emission allowances in return for emitting those GHGs. If Congress undertakes comprehensive tax reform in the coming year, it is possible that such reform may include a carbon tax, which could impose additional direct costs on operations and reduce demand for refined products. Although it is not possible at this time to predict how legislation or new regulations that may be adopted to address GHG emissions would impact our business, any such future laws and regulations 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.

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 published draft permitting guidance in May 2012 addressing the performance of such activities using diesel fuels. In November 2011, the EPA announced its intent to develop and issue regulations under the Toxic Substances Control Act to require companies to disclose information regarding the chemicals used in hydraulic fracturing; however, to date, the agency has not yet taken any action to do so. Furthermore, in April 2012, the EPA 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. 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 first progress report outlining work currently underway by the agency released in December 2012 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 by late 2014. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards at some point in 2014. 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 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.

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.

We have been an early entrant into new or emerging plays. As a result, our drilling results in these areas are uncertain, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

While our costs to acquire undeveloped acreage in new or emerging plays have generally been less than those of later entrants into a developing play, our drilling results in these areas are more uncertain than drilling results in areas that are developed and producing. Since new or emerging plays have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. As a result, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

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 2013, we had estimated average outstanding borrowings under our revolving credit facility of approximately $600 million, 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 $6 million and a corresponding decrease in our net income before the effects of income taxes. In addition, an increase in interest rates could result in our failure to complete the proposed initial public offering of our midstream business on the terms currently contemplated, or at all, a decrease in the proceeds we receive from the offering or a decrease in the value of the limited partnership interests we retain upon completion of the offering. 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.

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 2014 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 December 2013, the Ohio State House introduced a proposal to introduce a severance tax on production from horizontally fractured wells at a rate of 1 percent of the net value for the first five years. After that period, the rate would increase to 2 percent for high-producing wells, though the rate decreases to 1 percent when production declines. 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

We are party to various 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.

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. We paid a fine of $102,795 in December 2013 to resolve this matter. 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.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Common Stock

We have one class of common shares outstanding, our par value $0.01 per share Common Stock ("Common Stock"). Our Common Stock is traded on the New York Stock Exchange under the symbol "AR". On February 20, 2014, our Common Stock was held by 2 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 from October 10, 2013, the date the shares were first traded, through December 31, 2013. On February XX, 2014, the closing price of our Common Stock was $XX.

	Common Stock	
	High	Low
For the period from October 10, 2013 through December 31, 2013	$63.15	$51.56

Use of Proceeds

On October 16, 2013, we completed the initial public offering of common stock. The offering was comprised of an aggregate of 41,083,750 shares of common stock at $44.00 per share, which included 3,409,091 shares of common stock sold by the selling stockholder and 1,949,659 shares of common stock sold by us pursuant to the exercise in full by the underwriters of their option to purchase additional shares of common stock. Barclays, Citigroup, J.P. Morgan, Credit Suisse, Jefferies and Wells Fargo Securities acted as joint book running managers of the offering.

The gross proceeds of the IPO were approximately $1.8 billion. After subtracting (i) the net proceeds to the selling stockholders of approximately $143.3 million, (ii) underwriting discounts of approximately $81.4 million (approximately $74.6 million of which were paid by us and $6.8 million of which were paid by the selling stockholder) and (iii) offering expenses of approximately $5.0 million, we received net proceeds of approximately $1.6 billion.

We used approximately $1.43 billion of the net proceeds to repay outstanding borrowings under our revolving credit facility and approximately $150 million to redeem $140 million aggregate principal amount of our outstanding 7.25% senior notes due 2019.

Recent Sales of Unregistered Securities

On October 16, 2013, in connection with a corporate reorganization that was completed immediately prior to the closing of our initial public offering, Antero Resources LLC merged with and into Antero Resources Corporation pursuant to a merger agreement by and among Antero Resources LLC, Antero Resources Investment LLC and Antero Resources Corporation whereby, (a) Antero Resources LLC merged with and into Antero Resources Corporation, with Antero Resources Corporation surviving the merger, (b) all of the membership interests of Antero Resources LLC held by Antero Resources Investment LLC converted into 224,375,000 shares of outstanding common stock of Antero Resources Corporation, and (c) the membership interest in Antero Resources Investment LLC held by Antero Resources LLC was cancelled. The foregoing was undertaken in reliance upon an exemption from the registration requirements of the Securities Act by Section 4(a)(2) thereof.

Immediately after the reorganization and our initial public offering, Antero Resources Investment LLC ("Antero Investment") owned approximately 84.3% of our outstanding common stock.

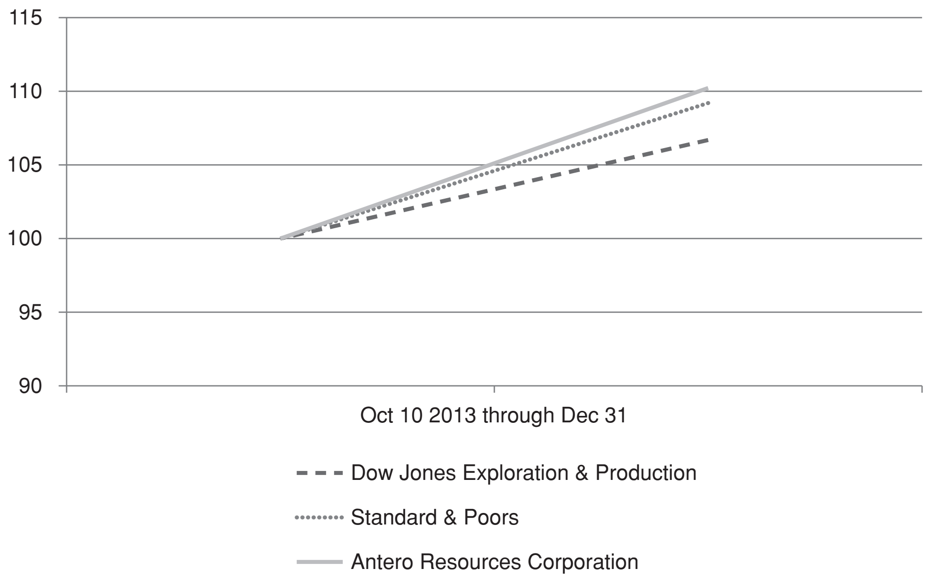
Dividend Restrictions

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 Antero's 7.25% senior notes due 2019, 6.00% senior notes due 2020, and 5.375% senior notes due 2021, and (iv) our revolving credit facility. We have not paid or declared any dividends on its Common Stock. The future payment of cash dividends on the 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 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 Return Among Antero Resources Corporation, the S&P 500 Index, and the Dow Jones US Exploration & Production Index



Item 6. Selected Financial Data

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

The selected statement of operations data for the years ended December 31, 2011, 2012 and 2013 and the balance sheet data as of December 31, 2012 and 2013 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, 2009, 2010, and 2011 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. 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.

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 December 31,				
(in thousands, except ratios)	**2009**	**2010**	**2011**	**2012**	**2013**
Statement of operations data:					
Operating revenues:					
Natural gas sales	$ 2,252	$ 47,392	$ 195,116	$ 259,743	$ 689,198
NGL sales	—	—	—	3,719	111,663
Oil sales	—	39	173	1,520	20,584
Commodity derivative fair value gains	3,910	77,599	496,064	179,546	491,689
Gain on sale of assets	—	—	—	291,190	—
Total revenues	6,162	125,030	691,353	735,718	1,313,134
Operating expenses:					
Lease operating	28	1,158	4,608	6,243	9,439
Gathering, compression, processing, and transportation	421	9,237	37,315	91,094	218,428
Production and ad valorem taxes	128	2,885	11,915	20,210	50,481
Exploration	2,095	2,350	4,034	14,675	22,272
Impairment of unproved properties	100	6,076	4,664	12,070	10,928
Depletion, depreciation, and amortization	1,706	18,522	55,716	102,026	233,876
Accretion of asset retirement obligations	—	11	76	101	1,065
Expenses related to acquisition of business	—	2,544	—	—	—
General and administrative (including $365,280 of stock compensation in 2013)	20,843	21,952	33,342	45,284	425,438
Loss on sale of compressor station	—	—	8,700	—	—
Total operating expenses	25,321	64,735	160,370	291,703	971,927
Operating income (loss)	(19,159)	60,295	530,983	444,015	341,207

(in thousands, except ratios)	Year Ended December 31, 2009	2010	2011	2012	2013
Other expenses:					
Interest expense	$ (36,053)	$ (56,463)	$ (74,404)	$ (97,510)	$ (136,617)
Loss on early extinguishment of debt	—	—	—	—	(42,567)
Interest rate derivative fair value losses	(4,985)	(2,677)	(94)	—	—
Total other expenses	(41,038)	(59,140)	(74,498)	(97,510)	(179,184)
Income (loss) before income taxes and discontinued operations	(60,197)	1,155	456,485	346,505	162,023
Income tax expense	—	(939)	(185,297)	(121,229)	(186,210)
Income (loss) from continuing operations	(60,197)	216	271,188	225,276	(24,187)
Discontinued operations:					
Income (loss) from results of operations and sale of discontinued operations, net of income tax	(45,972)	228,412	121,490	(510,345)	5,257
Net income (loss)	$ (106,169)	$ 228,628	$ 392,678	$ (285,069)	$ (18,930)
Balance sheet data (at period end):					
Cash and cash equivalents	$ 10,669	$ 8,988	$ 3,343	$ 18,989	$ 17,487
Other current assets	84,175	147,917	330,299	255,617	316,077
Total current assets	94,844	156,905	333,642	274,606	333,564
Natural gas properties, at cost (successful efforts method):					
Unproved properties	596,694	737,358	834,255	1,243,237	1,513,136
Producing properties	1,340,827	1,762,206	2,497,306	1,682,297	3,621,672
Fresh water distribution systems	—	—	—	6,835	231,684
Gathering systems and facilities	185,688	85,404	142,241	168,930	584,626
Other property and equipment	3,302	5,975	8,314	9,517	15,757
	2,126,511	2,590,943	3,482,116	3,110,816	5,966,875
Less accumulated depletion, depreciation, and amortization	(322,992)	(431,181)	(601,702)	(173,343)	(407,219)
Property and equipment, net	1,803,519	2,159,762	2,880,414	2,937,473	5,559,656
Other assets	38,203	169,620	574,744	406,714	720,361
Total assets	$1,936,566	$2,486,287	$3,788,800	$3,618,793	$ 6,613,581
Current liabilities	$ 112,493	$ 152,483	$ 255,058	$ 376,296	$ 622,229
Long-term indebtedness	515,499	652,632	1,317,330	1,444,058	2,078,999
Other long-term liabilities	9,467	86,185	257,606	124,702	313,693
Total equity	1,299,107	1,594,987	1,958,806	1,673,737	3,598,660
Total liabilities and equity	$1,936,566	$2,486,287	$3,788,800	$3,618,793	$ 6,613,581
Other financial data:					
EBITDAX from continuing operations	$ (15,857)	$ 27,824	$ 160,259	$ 284,710	$ 649,358
EBITDAX from discontinued operations	217,127	169,854	180,562	149,605	—
Total EBITDAX	$ 201,270	$ 197,678	$ 340,821	$ 434,315	$ 649,358
Net cash provided by operating activities	$ 149,307	$ 127,791	$ 266,307	$ 332,255	$ 534,707
Net cash used in investing activities	$ (281,899)	$ (230,672)	$ (901,249)	$ (463,491)	$(2,673,592)
Net cash provided by financing activities	$ 104,292	$ 101,200	$ 629,297	$ 146,882	$ 2,137,383
Capital expenditures	$ 281,674	$ 390,974	$ 903,422	$1,682,549	$ 2,671,573

"EBITDAX" is a non-GAAP financial measure that we define as net income (loss) before interest expense or interest income, derivative fair value gains or losses, excluding net cash receipts or payments on derivative instruments, taxes, impairments, depletion, depreciation, amortization, exploration expense, franchise taxes, stock compensation, business acquisition and gain or loss on sale of assets. "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. 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. EBITDAX provides no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, and working capital movement or tax position. 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 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 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 EBITDAX reported by different companies. The following table represents a reconciliation of our net income (loss) from continuing operations to EBITDAX from continuing operations, a reconciliation of our net income (loss) from discontinued operations to EBITDAX from discontinued operations, and a reconciliation of our total EBITDAX to net cash provided by operating activities per our consolidated statements of cash flows, in each case for the periods presented:

(in thousands)	Year Ended December 31, 2009	2010	2011	2012	2013
Net income (loss) from continuing operations	$(60,197)	$ 216	$ 271,188	$ 225,276	$ (24,187)
Commodity derivative fair value gains[(1)]	(3,910)	(77,599)	(496,064)	(179,546)	(491,689)
Net cash receipts on settled derivative instruments[(1)]	—	15,063	49,944	178,491	163,570
Loss (gain) on sale of assets	—	—	8,700	(291,190)	—
Interest expense, loss on early extinguishment of debt, and interest rate derivative fair value losses	41,038	59,140	74,498	97,510	179,184
Provision for income taxes	—	939	185,297	121,229	186,210
Depreciation, depletion, amortization, and accretion	1,706	18,533	55,792	102,127	234,941
Impairment of unproved properties	100	6,076	4,664	12,070	10,928
Exploration expense	2,095	2,350	4,034	14,675	22,272
Stock compensation expense	—	—	—	—	365,280
Other	3,311	3,106	2,206	4,068	2,849
EBITDAX from continuing operations	(15,857)	27,824	160,259	284,710	649,358
Net income (loss) from discontinued operations	(45,972)	228,412	121,490	(510,345)	5,257
Commodity derivative fair value gains[(1)]	(51,455)	(166,685)	(180,130)	(46,358)	—
Net cash receipts on settled derivative instruments[(1)]	116,550	58,650	66,654	92,166	—
(Gain) loss on sale of assets	—	(147,559)	—	795,945	(8,506)
Provision (benefit) for income taxes	(2,605)	29,070	45,155	(272,553)	3,249
Depreciation, depletion, amortization, and accretion	138,372	115,739	115,164	89,124	—
Impairment of unproved properties	54,104	29,783	6,387	962	—
Exploration expense	8,133	22,444	5,842	664	—
EBITDAX from discontinued operations	217,127	169,854	180,562	149,605	—
Total EBITDAX	$201,270	$ 197,678	$ 340,821	$ 434,315	$ 649,358
Interest expense and other	(41,038)	(59,140)	(74,498)	(97,510)	(144,422)
Exploration expense	(10,228)	(24,794)	(9,876)	(15,339)	(22,272)
Changes in current assets and current liabilities	(2,648)	(698)	8,309	9,887	41,914
Other	1,951	14,745	1,551	902	10,129
Net cash provided by operating activities	$149,307	$ 127,791	$ 266,307	$ 332,255	$ 534,707

(1) The adjustments for the derivative fair value (gains) losses and net cash receipts on settled commodity derivative instruments have the effect of adjusting net income (loss) from continuing operations for changes in the fair value of derivative instruments, which are recognized at the end of each accounting period because we do not designate commodity derivative instruments as accounting hedges. This results in reflecting commodity derivative gains and losses on a cash basis during the period the derivatives settled.

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, NGL and oil prices, the timing of planned capital expenditures, 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," "our," and "operating entities" refer to the subsidiaries that conduct our operations, unless otherwise indicated or the context otherwise requires.

Our Company

We are 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 in West Virginia, Ohio and Pennsylvania. We are focused on creating shareholder value through the development of our large portfolio of repeatable, low cost, liquids-rich drilling opportunities in two of the premier North American shale plays. As of December 31, 2013, we held approximately 345,000 net acres in the southwestern core of the Marcellus Shale and approximately 105,000 net acres in the core of the Utica Shale. In addition, we estimate that approximately 180,000 net acres of our Marcellus Shale leasehold are prospective for the slightly shallower Upper Devonian Shale. Finally, we own the deep rights on approximately 126,000 net acres of our Marcellus Shale acreage in West Virginia that we believe is prospective for the dry gas Utica Shale. As of December 31, 2013, our estimated proved reserves were 7.6 Tcfe and were 27% proved developed and 88% natural gas, assuming ethane rejection. As of December 31, 2013, our drilling inventory consisted of 4,778 identified potential horizontal well locations, approximately 68% of which are liquids-rich drilling opportunities.

The statement of operations data for all periods presented in this "Management's Discussion and Analysis of Financial Condition and Results of Operations" has been recast to present the results of operations from our Arkoma Basin and Piceance operations in discontinued operations.

Source of Our Revenues

Our revenues are 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 2013 our revenues from production were comprised of approximately 84% from the sale of natural gas and 16% from the sale of NGLs and oil. Natural gas, NGL, 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 natural gas production. We currently use fixed price natural gas 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 unsettled commodity derivative instruments in earnings at the end of each accounting period. We expect continued volatility in the fair value of these 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 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 that may include minimum volume commitments, the cost for which is included in these expenses.
- *Production taxes.* Production taxes consist of severance and ad valorem taxes and 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.
- *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 could record impairment charges for proved properties if the carrying value were to exceed estimated future cash flows. Through December 31, 2013, we have not recorded any impairment for proved properties.
- *Depreciation, depletion and amortization.* Depreciation, depletion 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 stock compensation charge, including a charge of $365 million recorded in 2013 for vested profits interests upon the completion of the IPO. 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, 2013 we had a fixed interest rate of 5.375% on our senior notes having a principal balance of $1 billion, a fixed interest rate of 7.25% on our senior notes having a principal balance of $260 million, and a fixed

interest rate of 6.00% on our senior notes having a principal balance of $525 million. 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 unrealized commodity hedge gains for tax purposes until they are realized. 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 2033. We recorded valuation allowances for deferred tax assets at December 31, 2013 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.

Results of Operations

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

The following table sets forth selected operating data (as recast for discontinued operations) for the year ended December 31, 2012 compared to the year ended December 31, 2013:

(in thousands, except per unit data)	Year Ended December 31, 2012	Year Ended December 31, 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 stock compensation)	45,284	60,158	14,874	33%
Stock compensation	—	365,280	365,280	*
Total operating expenses	291,703	971,927	680,224	*
Operating income	444,015	341,207	(102,808)	*
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)	*
Income taxes expense	(121,229)	(186,210)	(64,981)	54%
Income from continuing operations	225,276	(24,187)	(249,463)	*
Income (loss) from discontinued operations	(510,345)	5,257	515,602	*
Net income (loss)	$(285,069)	$ (18,930)	$ 266,139	*
EBITDAX from continuing operations[1]	$ 284,710	$ 649,358	$ 364,648	128%
EBITDAX from discontinued operations[1]	149,605	—	(149,605)	*
Total EBITDAX[1]	$ 434,315	$ 649,358	$ 215,043	50%
Production data:				
Natural gas (Bcf)	87	177	90	103%
NGLs (MBbl)	71	2,123	2,052	2,872%
Oil (MBbl)	19	226	207	1,094%
Combined (Bcfe)	87	191	104	119%
Daily combined production (MMcfe/d)	239	522	283	119%
Average sales prices before effects of cash settled derivatives[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 sales prices after effects of cash settled derivatives[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 taxes	$ 0.23	$ 0.26	$ 0.03	13%
Depletion, depreciation, amortization, and accretion	$ 1.17	$ 1.23	$ 0.06	5%
General and administrative[3]	$ 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).

(2) Average sales prices shown in the table reflect both of the before and after effects of our cash settled derivatives. Our calculation of such after effects includes realized 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.

(3) Does not include noncash stock compensation in 2013.

* 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). The sale included approximately 25 miles of low pressure pipeline systems and gathering rights on 104,000 net acres held by us within a 250,000 acre AOD and had an effective date of January 1, 2012. Other third-party producers will also have access to the Crestwood system. During the first seven years of the contract, we are committed to deliver minimum volumes into the gathering systems, with certain carryback and carryforward adjustments for overages or deficiencies. We can earn up to an additional $40 million of sale proceeds if we meet certain volume thresholds over the first three years of the contract. Crestwood is obligated to incur all future capital costs to build out gathering systems and compression facilities within the AOD to connect our wells as we execute our drilling program and has assumed the various risks and rewards of the system build-out and operations. Because we have not retained the substantial risks and rewards of ownership associated with the gathering rights and systems transferred to Crestwood, we have recognized a gain on the sale of the gathering system and gathering rights of approximately $291 million.

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 primarily because of costs increasing at a lower rate than production. Because our Appalachian Basin properties are in an early stage of production, production rates are high and per unit lease operating expenses are relatively low. Lease operating expenses are expected to 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 7.6% for the year ended December 31, 2012 compared to 6.1% for the year ended December 31, 2013. 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.

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 $12 million for the year ended December 31, 2012 compared to $11 million for the year ended December 31, 2013. We charge impairment expense for expired or soon-to-be expired leases when we determine they are impaired through lack of drilling activities or based on other 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 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 stock 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 stock 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 stock 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 stock compensation expense in 2013 relative to these interests and will recognize approximately another $121 million over the remaining expected service period. The stock 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 stock 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. A detailed 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.

EBITDAX from continuing and discontinued operations. 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 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. 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.

Segment information. In 2013, we have begun reporting our midstream gathering and water distribution operations as reportable segments. Prior to 2013, such operations were immaterial and considered ancillary to our exploration and production activities. Following is a summary of our segment information for the year ended 2013:

	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
Depletion, depreciation, and amortization	$ 220,857	11,346	2,773	(1,100)	233,876
Interest expense	$ 136,453	155	9	—	136,617
Income tax expense	$ 186,210	—	—	—	186,210
Operating income(1)	$ 335,901	8,938	27,296	(30,928)	341,207
Segment assets	$6,580,282	561,855	230,247	(758,803)	6,613,581
Capital expenditures for segment assets	$2,110,358	389,453	203,790	(32,028)	2,671,573

(1) All general and administrative expenses are included in the exploration and production segment.

Intracompany midstream revenues of $58 million resulted from gathering and water distribution charges as we expanded our company-operated gathering systems and began supplying water from our water pipeline and delivery infrastructure for well completions. Capital expenditures for these midstream operations totaled $593 million in 2013.

Year Ended December 31, 2011 Compared to Year Ended December 31, 2012

The following table sets forth selected operating data (as recast for discontinued operations) for the year ended December 31, 2011 compared to the year ended December 31, 2012:

(in thousands, except per unit data)	Year Ended December 31, 2011	Year Ended December 31, 2012	Amount of Increase (Decrease)	Percent Change
Operating revenues:				
Natural gas sales	$ 195,116	$ 259,743	$ 64,627	33%
NGL sales	—	3,719	3,719	*
Oil sales	173	1,520	1,347	779%
Commodity derivative fair value gains	496,064	179,546	(316,518)	(63)%
Gain on sale of assets	—	291,190	291,190	*
Total operating revenues	691,353	735,718	44,365	6%
Operating expenses:				
Lease operating	4,608	6,243	1,635	35%
Gathering, compression, processing, and transportation	37,315	91,094	53,779	144%
Production and ad valorem taxes	11,915	20,210	8,295	70%
Exploration	4,034	14,675	10,641	264%
Impairment of unproved properties	4,664	12,070	7,406	159%
Depletion, depreciation, and amortization	55,716	102,026	46,310	83%
Accretion of asset retirement obligations	76	101	25	33%
General and administrative	33,342	45,284	11,942	36%
Loss on sale of compressor station	8,700	—	(8,700)	*
Total operating expenses	160,370	291,703	131,333	82%
Operating income	530,983	444,015	(86,968)	(16)%
Other expenses:				
Interest expense	$ (74,404)	$ (97,510)	$ 23,106	31%
Interest rate derivative fair value loss	(94)	—	(94)	*
Total other expenses	(74,498)	(97,510)	23,012	31%
Income before income taxes and discontinued operations	456,485	346,505	(109,980)	(24)%
Income taxes expense	(185,297)	(121,229)	(64,068)	(35)%
Income from continuing operations	271,188	225,276	(45,912)	(17)%
Income (loss) from discontinued operations	121,490	(510,345)	(631,835)	*
Net income (loss) attributable to Antero equity owners	$ 392,678	$(285,069)	$(677,747)	(173)%
EBITDAX from continuing operations(1)	$ 160,259	$ 284,710	$ 124,451	78%
EBITDAX from discontinued operations(1)	180,562	149,605	(30,957)	(17)%
Total EBITDAX(1)	$ 340,821	$ 434,315	$ 93,494	27%
Production data:				
Natural gas (Bcf)	45	87	42	93%
NGLs (MBbl)	—	71	71	*
Oil (MBbl)	2	19	17	963%
Combined (Bcfe)	45	87	42	93%
Daily combined production (MMcfe/d)	124	239	115	93%
Average sales prices before effects of cash settled derivatives(2):				
Natural gas (per Mcf)	$ 4.33	$ 2.99	$ (1.34)	(31)%
NGLs (per Bbl)	$ —	$ 52.07	$ 52.07	*
Oil (per Bbl)	$ 97.19	$ 80.34	$ (16.85)	(17)%
Combined (per Mcfe)	$ 4.33	$ 3.03	$ (1.30)	(30)%
Average realized sales prices after effects of cash settled derivatives(2):				
Natural gas (per Mcf)	$ 5.44	$ 5.05	$ (0.39)	(7)%
NGLs (per Bbl)	$ —	$ 52.07	$ 52.07	*
Oil (per Bbl)	$ 97.19	$ 80.34	$ (16.85)	(17)%
Combined (per Mcfe)	$ 5.44	$ 5.08	$ (0.36)	(7)%
Average costs (per Mcfe):				
Lease operating	$ 0.10	$ 0.07	$ (0.03)	(30)%
Gathering compression, processing, and transportation	$ 0.83	$ 1.04	$ 0.21	25%
Production taxes	$ 0.26	$ 0.23	$ (0.03)	(12)%
Depletion depreciation, amortization, and accretion	$ 1.24	$ 1.17	$ (0.07)	(6)%
General and administrative	$ 0.74	$ 0.52	$ (0.22)	(30)%

(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).

(2) Average sales prices shown in the table reflect both of the before and after effects of our cash settled derivatives. Our calculation of such after effects includes realized 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 $195 million for the year ended December 31, 2011 to $265 million for the year ended December 31, 2012, an increase of $70 million, or 36%. Our production increased by 93% from 45 Bcfe in 2011 to 87 Bcfe in 2012. Increased production volumes increased revenues by $183 million, or 93%, (calculated as the increase in year-to-year volumes times the prior year average price), and combined commodity price decreases accounted for a $113 million, or 58% decrease in revenues (calculated as the decrease 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 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, 2011 and 2012, our hedges resulted in derivative fair value gains of $496 million and $180 million, respectively. The derivative fair value gains included $46 million and $178 million of cash settlements received on derivatives for the years ended December 31, 2011 and 2012, 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, or AOD, to a joint venture owned by Crestwood Midstream Partners and Crestwood Holdings Partners LLC (together, "Crestwood") for $375 million (subject to customary purchase price adjustments). The sale included approximately 25 miles of low pressure pipeline systems and gathering rights on 104,000 net acres held by us within a 250,000 acre AOD and had an effective date of January 1, 2012. Other third-party producers will also have access to the Crestwood system. During the first seven years of the contract, we are committed to deliver minimum volumes into the gathering systems, with certain carryback and carryforward adjustments for overages or deficiencies. We can earn up to an additional $40 million of sale proceeds if we meet certain volume thresholds over the first three years of the contract. Crestwood is obligated to incur all future capital costs to build out gathering systems and compression facilities within the AOD to connect our wells as it executes its drilling program and has assumed the various risks and rewards of the system build-out and operations. Because we have not retained the substantial risks and rewards of ownership associated with the gathering rights and systems transferred to Crestwood, it has recognized a gain on the sale of the gathering system and gathering rights of approximately $291 million.

Lease operating expenses. Lease operating expenses increased from $5 million for the year ended December 31, 2011 to $6 million in 2012, primarily as a result of increased production. On a per-Mcfe basis, lease operating expenses decreased by 30%, from $0.10 per Mcfe in 2011 to $0.07 per Mcfe in 2012 primarily because of costs increasing at a lower rate than production. Because our Appalachian Basin properties are in a relatively early stage of production, production rates are high and per unit lease operating expenses are low. Lease operating expenses are expected to 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 $37 million for the year ended December 31, 2011 to $91 million in 2012. The increase in these expenses resulted from the increase in production, increased firm transportation commitments, and increases in third-party compression and gathering expenses as we outsourced some of our compression and gathering. On a per-Mcfe basis, total gathering, compression, processing and transportation expenses increased from $0.83 per Mcfe for 2011 to $1.04 in 2012 due to increased third-party gathering changes and increased processing costs.

Production and ad valorem tax expense. Total production taxes increased from $12 million for the year ended December 31, 2011 to $20 million for the year ended December 31, 2012, 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, 2011 compared to 7.6% for the year ended December 31, 2012. Production taxes as a percentage of revenues increased as prices decreased resulting in the fixed portion of production taxes being a higher percentage of revenues.

Exploration expense. Exploration expense increased from $4 million for the year ended December 31, 2011 to $15 million for the year ended December 31, 2012 primarily because of an increase in the cost of unsuccessful lease acquisition efforts as we increased the number of third-party lease brokers providing services to us in the Appalachian Basin.

Impairment of unproved properties. Impairment of unproved properties was approximately $5 million for the year ended December 31, 2011 compared to $12 million for the year ended December 31, 2012. The increase in impairment charges was due to an increase in expiring acreage and ongoing evaluation of our undeveloped Marcellus acreage. We charge impairment expense for expired or soon-to-be expired leases when we determine they are impaired through lack of drilling activities or based on other 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 $56 million for the year ended December 31, 2011 to $102 million for the year ended December 31, 2012, an increase of $46 million, as a result of increased production in 2012 compared to 2011. DD&A per Mcfe decreased 6%, from $1.24 per Mcfe during 2011 to $1.17 per Mcfe during 2012 as a result of the increased proved reserves in 2012.

General and administrative expense. General and administrative expense increased from $33 million for the year ended December 31, 2011 to $45 million during 2012, an increase of $12 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 107 at December 31, 2011 to 150 at December 31, 2012. On a per-Mcfe basis, general and administrative expense decreased by 30%, from $0.74 per Mcfe during the year ended December 31, 2011 to $0.52 per Mcfe during 2012 primarily due to a 93% growth in production. No portion of general and administrative expenses was allocated to discontinued operations as we do 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 for both 2011 and 2012.

Interest expense and interest rate derivative fair value loss. Interest expense increased from $74 million for the year ended December 31, 2011 to $98 million for the year ended December 31, 2012, an increase of $24 million as a result of an increase in the amount of senior notes outstanding during 2012 compared to during 2011.

Income tax expense. For each tax year-end through December 31, 2011, Antero Resources LLC and each of its subsidiaries filed separate federal and state income tax returns. Antero Resources LLC is a partnership for income tax purposes and therefore is not subject to federal or state income taxes. The tax on the income of Antero Resources LLC is borne by its individual members through the allocation of taxable income. In October 2012, we completed a reorganization of its legal structure by contributing all of the outstanding shares owned by Antero Resources LLC in each of the Antero Arkoma, Antero Piceance, and Antero Pipeline corporations to Antero Appalachian. Antero Arkoma, Antero Piceance, and Antero Pipeline were first converted to limited liability companies and then liquidated as part of the reorganization. As a result, for income tax purposes, the operations subsequent to the liquidations and tax attributes of Arkoma, Piceance and Pipeline are now combined with Antero Appalachian for tax reporting purposes.

Income tax expense related to continuing operations was $121 million in 2012 compared to $185 million in 2011. Although we have accrued $15 million at December 31, 2012 for unrecognized tax benefits, no taxes were due at the end of either December 31, 2011 or 2012. 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, 2012, we had approximately $1.0 billion of U.S. Federal net operating loss carryforwards, or NOLs, and approximately $1.3 billion of state NOLs, which expire starting in 2024 and through 2032. At December 31, 2012, we recorded valuation allowances of approximately $48 million for deferred tax assets primarily related to capital loss and state loss carryforwards.

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. A detailed analysis of these operations is included in note 3 to the consolidated financial statements included elsewhere in this report. Income (loss) from discontinued operations decreased from income of $121 million in 2011 to a loss of $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.

EBITDAX from continuing and discontinued operations. EBITDAX from continuing operations increased to $285 million for the year ended December 31, 2012 from $160 million for the year ended December 31, 2011, and increase of 78%. The increase in EBITDAX resulted from a 93% increase in production, net of a 7% decrease in the average per Mcfe price received after the impact of cash settled derivatives and the related increases in cash operating and general and administrative expenses. EBITDAX from discontinued operations related to the Piceance and Arkoma Basin assets disposed of in 2012 decreased from $181 million for the year ended December 31, 2011 to $150 million in 2012 because the Arkoma Basin assets were owned for only part of 2012.

Capital Resources and Liquidity

Historically, our primary sources of liquidity have been through issuances of debt securities, borrowings under our revolving credit facility, asset sales, and net cash provided by operating activities. During 2013, we raised capital through our IPO receiving net proceeds of $1.6 billion, the issuance of $225 million of 6.00% senior notes due 2020, and the issuance of $1 billion of 5.375% senior notes due 2021. Our primary use of cash has been for the exploration, development and acquisition of natural gas, NGLs, and oil properties. 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, 2013, we had 4,778 identified potential horizontal well locations, which will take many years to develop. More specifically, our proved undeveloped reserves will require an estimated $5.3 billion of development capital over the next five years. 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 conduct drilling activities on these identified potential well locations and to finance the development of our proved undeveloped reserves.

Our revolving credit facility has a borrowing base of $2.0 billion and current lender commitments of $1.5 billion. Current lender commitments can be increased to the full borrowing base upon approval of the lending bank group. 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 April 2014. 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. 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 16 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 February 7, 2014, Antero Resources Midstream LLC (to be converted into a limited partnership named Antero Midstream Partners LP) (the "Partnership") filed a registration statement on Form S-1 (the "S-1") with the SEC relating to a proposed underwritten initial public offering as a master limited partnership that will own and operate our midstream business. Upon completion of the initial public offering, we expect to retain a substantial portion of the Partnership's common and subordinated units. The Partnership's general partner interest and incentive distribution rights will be owned by a subsidiary of Antero Resources Investment LLC. We expect to receive the net proceeds of the offering as repayment of indebtedness and reimbursement for pre-contribution capital expenditures. We plan to use the proceeds we receive to repay outstanding borrowings under our credit facility.

For the year ended December 31, 2013, our capital expenditures were approximately $2.7 billion for drilling, leasehold acquisitions, freshwater distribution systems, and gathering systems and facilities. Our capital budget for 2014 is $2.6 billion and includes: $1.8 billion for drilling and completion; $600 million for the expansion of midstream facilities, including $200 million for fresh water distribution infrastructure; and $200 million for core leasehold acreage acquisitions. We periodically review our capital expenditures and adjust our budget accordingly. Historically, we have increased our budget to take advantage of opportunistic leasehold acreage acquisitions and new capital project opportunities. In addition, we have adjusted our drilling, completion and gathering budgets in response to drilling results, liquidity changes and commodity prices.

We believe that funds from operating cash flows, available borrowings under our revolving credit facility, and repayment of indebtedness and reimbursement for pre-contribution capital expenditures from the Partnership 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, 2011, 2012, and 2013:

	Year Ended December 31,		
	2011	2012	2013
		(in thousands)	
Net cash provided by operating activities	$ 266,307	$ 332,255	$ 534,707
Net cash used in investing activities	(901,249)	(463,491)	(2,673,592)
Net cash provided by financing activities	629,297	146,882	2,137,383
Net increase (decrease) in cash and cash equivalents	$ (5,645)	$ 15,646	$ (1,502)

Cash Flow Provided by Operating Activities

Net cash provided by operating activities was $266 million, $332 million and $535 million for the years ended December 31, 2011, 2012 and 2013, respectively. The increase in cash flows from operations from 2011 to 2012 and also from 2012 to 2013 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, 2011, 2012 and 2013, we used cash flows in investing activities of $901 million, $463 million and $2.7 billion, respectively, as a result of our capital expenditures for drilling, development and acquisitions. 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 $2.6 billion for 2014. 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 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.

Net cash provided by financing activities in 2011 of $629 million was primarily the result of (i) $400 million of cash provided by the issuance of senior notes, (ii) net borrowings of $265 million on our revolving credit facility, net of (iii) cash outflows of $7 million for deferred financing costs, and a $29 million distribution to equity members for tax liabilities.

Debt Agreements and Contractual Obligations

Senior Secured Revolving Credit Facility. Our revolving credit facility provides for a maximum borrowing base of $2.5 billion and at December 31, 2013 has a borrowing base of $2.0 billion. The borrowing base is redetermined semi-annually and the borrowing base depends on 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 April 2014. Current lender commitments are $1.5 billion and can be increase to the full $2.0 billion upon approval of the lending group. At December 31, 2013, we had $288 million of borrowings and $32 million of letters of credit outstanding under our revolving credit facility. Our revolving credit facility matures in May 2016.

Principal amounts borrowed are payable on the maturity date 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 rate appearing on the Reuters BBA Libor Rates Page 3750 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 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. For information concerning the effect of changes in interest rates on interest payments under this facility, see "Item 7A. Quantitative and Qualitative Disclosure About Market Risk." As of December 31, 2012 and 2013, borrowings and letters of credit outstanding under our senior secured revolving credit facility totaled $217 million and $288 million, respectively, and had a weighted average interest rate of 1.91% and 1.61%, respectively. The facility contains 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.

Our revolving credit facility also requires us to maintain the following two financial ratios:

- a current ratio, which is the ratio of our consolidated current assets (as defined) 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, of not less than 2.5 to 1.0.

We were in compliance with such covenants and ratios as of December 31, 2012 and 2013.

Senior Notes. We have $1 billion of 5.375% senior notes outstanding, which are due November 1, 2021. The notes are unsecured and effectively subordinated to our revolving credit facility to the extent of the value of the collateral securing the revolving credit facility. The notes rank parri passu to our other outstanding senior notes. The notes are guaranteed by our wholly owned subsidiary and certain of our future restricted subsidiaries. Interest on the notes is payable on May 1 and November 1 of each year. We may redeem all or part of the 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 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 notes, in whole or in part, at a price equal to 100% of the principal amount of the notes plus a "make-whole" premium. If we undergo a change of control prior to May 1, 2015, we may be required to repurchase all or a portion of the notes at a price equal to 110% of the principal amount of the notes, plus accrued interest.

We also have 7.25% senior notes outstanding with an original principal amount of $400 million, which are due August 1, 2019. The notes are unsecured and effectively subordinated to our revolving credit facility to the extent of the value of the collateral securing our revolving credit facility. The notes rank pari passu to our other outstanding senior notes. The notes are guaranteed on a senior unsecured basis by our wholly owned subsidiary and certain of our future restricted subsidiaries. Interest on the notes is payable on August 1 and February 1 of each year. We may redeem all or part of the notes at any time on or after August 1, 2014 at redemption prices ranging from 105.438% on or after August 1, 2014 to 100.00% on or after August 1, 2017. If we undergo a change of control, we may be required to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the notes, plus accrued interest. In November 2013, we used a portion of the proceeds from our IPO to redeem $140 million aggregate principal amount of our outstanding 7.25% senior notes.

We also have $525 million of 6.00% senior notes outstanding, which are due December 1, 2020. The notes are unsecured and effectively subordinated to our revolving credit facility to the extent of the value of the collateral securing our revolving credit facility. The notes rank pari passu to our other outstanding senior notes. The notes are guaranteed on a senior unsecured basis by our wholly owned subsidiary and certain of its future restricted subsidiaries. Interest on the notes is payable on June 1 and December 1 of each year, commencing on June 1, 2013. We may redeem all or part of the 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 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 notes, plus accrued interest. At any time prior to December 1, 2015, we may redeem the notes, in whole or in part, at a price equal to 100% of the principal amount of the notes plus a "make-whole" premium and accrued interest.

We used the proceeds from the issuances of the senior notes to repay borrowings outstanding under our revolving credit facility 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, 2012 and 2013.

Treasury Management Facility. We have a stand-alone revolving note with a lender under our revolving 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, 2014. At December 31, 2012, there were no outstanding borrowings under this facility.

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

(in millions)	2014	2015	2016	2017	2018	Thereafter	Total
Credit Facility[1]	$ —	$ —	$288	$ —	$ —	$ —	$ 288
Senior notes—principal[2]	—	—	—	—	—	1,785	1,785
Senior notes—interest[2]	104	104	104	104	104	216	736
Drilling rig and frac service commitments[3]	151	68	14	—	—	—	233
Firm transportation[4]	121	160	161	158	159	1,003	1,762
Gas processing, gathering, and compression services[5]	183	185	196	193	189	836	1,782
Office and equipment leases	4	4	4	3	2	14	31
Asset retirement obligations[6]	—	—	—	—	—	12	12
Total	$563	$521	$767	$458	454	$3,866	$6,629

(1) Includes outstanding principal amount at December 31, 2013. This table does not include future commitment fees, interest expense or other fees on our revolving credit 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 7.25% senior notes due 2019, the 6.00% senior notes issued in November 2012 and due 2020, and the 5.375% notes due 2021.

(3) At December 31, 2013, we had contracts for the services of 20 rigs, which expire at various dates from March 2014 through November 2016. We also had two frac services contracts. 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) We have entered into 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 NGL volumes at a negotiated rate, or pay for any deficiencies at a specified reservation fee rate. 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 service 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) 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 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

Our natural gas, NGL, and oil exploration and production activities are accounted for using the successful efforts method. Under this method, costs of drilling successful exploration wells and development costs are capitalized and amortized on a geological reservoir basis using the unit-of-production method as natural gas, NGL, and oil is produced. Geological and geophysical costs, delay rentals, costs related to unsuccessful lease acquisitions, and costs to drill exploratory wells that do not discover proved reserves are expensed as exploration costs. The costs of development wells are capitalized whether productive or nonproductive. Natural gas, NGL, and oil lease acquisition costs related to successful lease acquisitions are also capitalized. 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 unit-of-production amortization rate. Maintenance and repairs are charged to expense, and renewals and betterments are capitalized to the appropriate property and equipment accounts.

Unproved property costs are costs related to unevaluated properties and are transferred to proved natural gas and oil properties if the properties are determined to be productive. Proceeds from sales of partial interests in unproved leases are accounted for as a recovery of cost without recognizing any gain until all costs are recovered. Unevaluated natural gas, NGL, and oil properties are assessed periodically for impairment on a property-by-property basis based on remaining lease terms, drilling results, reservoir performance, commodity price outlooks or future plans to develop acreage. If it is determined that it is probable that reserves will not be discovered, the cost of unproved leases is charged to impairment of unproved properties. During the years ended December 31, 2011, 2012 and 2013, we charged impairment expense for expired or expiring leases with a cost of $11 million, $13 million, $11 million, respectively. The assessment of unevaluated natural gas, NGL, and oil properties to determine any possible impairment requires managerial judgment.

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. 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, NGL and Oil Reserve Quantities and Standardized Measure of Future Cash Flows

Our internal technical staff prepare the estimates of natural gas, NGL, 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, NGL, and oil reserves to be included in our financial statement disclosures. The SEC has defined proved reserves as the estimated quantities of natural gas, NGL, 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 are updated annually and consider recent production levels and other technical information about each field. Natural gas, NGL, and oil reserve engineering is a subjective process of estimating underground accumulations of natural gas, NGL, 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, NGL, 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, NGL, 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, NGL, 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 and oil properties and compare these future cash flows to the carrying amount of the gas and oil properties to 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 natural gas, NGL, and oil 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 will be recorded. We did not record any impairment charges for proved properties in 2011, 2012 or 2013.

Off-Balance Sheet Arrangements

As of December 31, 2013, we did not have any off-balance sheet arrangements other than operating leases and contractual commitments for drilling rigs, frac services, firm transportation, and gas processing, gathering and compression. See "—Debt Agreements and Contractual Obligations—Contractual Obligations" for commitments under operating leases, drilling rig and frac service agreements, firm transportation agreements, and gas processing and compression service agreements.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

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, NGL, 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 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 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 natural gas prices, we have entered into financial commodity swap contracts to receive fixed prices for a portion of our natural gas 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 and oil prices at targeted levels and to manage our exposure to natural gas 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 and cashless collars that set floor and ceiling prices for the hedged production. 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.

At December 31, 2013, we had in place natural gas and oil swaps covering portions of our projected production from 2014 through 2019. Our commodity hedge position as of December 31, 2013 is summarized in note 11 to our consolidated financial statements included elsewhere herein. Our financial hedging activities are intended to support natural gas, NGL, and oil prices at targeted levels and to manage our exposure to natural gas price fluctuations. Our revolving credit facility allows us to hedge up to 85% of our estimated production from proved reserves for up to 12 months in the future, 80% for 13 to 24 months in the future, 75% for 25 to 36 months in the future, 70% for 37 to 48 months in the future, 65% for 49 to 60 months in the future, and 65% of production for 2019. Based on our annual production and our fixed price swap contracts in place during 2013, our income before taxes for the year ended December 31, 2013 would have decreased by approximately $2.5 million for each $0.10 decrease per MMBtu in natural gas 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 the consolidated balance sheets as assets or liabilities. Fair values are adjusted for non-performance risk.

Because we do not designate these hedges as accounting hedges, we 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 as "Derivative fair value gains (losses)."

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, 2012 and 2013, the estimated fair value of our commodity derivative instruments was a net asset of $532 million and $860 million, respectively, comprised of current and noncurrent assets and current liabilities. None of these commodity derivative instruments were entered into for trading or speculative purposes.

By removing price volatility from a portion of our expected natural gas production through December 2019, 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.

Interest Rate Risks

Our primary exposure to interest rate risk results from outstanding borrowings under our revolving credit facility, which has a floating interest rate. The average annual interest rate incurred on this indebtedness for the year ended December 31, 2013 was approximately 2.2%. A 1.0% increase in each of the average LIBOR rate and federal funds rate for the year ended December 31, 2013 would have resulted in an estimated $6 million increase in interest expense for that period. We had no outstanding interest rate derivatives at December 31, 2013.

Counterparty and Customer Credit Risk

Our principal exposures to credit risk are through receivables resulting from commodity derivatives contracts ($860 million at December 31, 2013) and the sale of our oil and gas production ($97 million at December 31, 2013), which we market to energy companies.

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. The fair value of our commodity derivative contracts of approximately $860 million at December 31, 2013 includes the following values by bank counterparty: BNP Paribas—$197 million; Credit Suisse—$190 million; Barclays—$147 million; Wells Fargo—$140 million; JP Morgan—$134 million; Citigroup—$34 million; Deutsche Bank—$15 million; and Toronto Dominion Bank—$3 million. The credit ratings of certain of these banks have been downgraded 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, 2013 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 contracts, nor are they required to provide credit support to us. As of December 31, 2013, we did not have past-due receivables from or payables to any of our counterparties.

We are also subject to credit risk due to concentration of our natural gas receivables with several significant customers. We do not require all 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.

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 on pages F-[1] through F-[26] of this report and are incorporated herein by reference.

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

Not applicable.

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, 2013.

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 2013 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 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 1992, 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, 2013.

Management's report was not subject to attestation by our independent registered public accounting firm pursuant to rules of the Securities and Exchange Commission that permit us to provide only management's report in this Annual Report on Form 10-K. Therefore, this Annual Report on Form 10-K does not include such an attestation.

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 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 U.S. 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) indirectly beneficially own more than 10% of our outstanding common stock and 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.

EIG

The disclosure below relates solely to activities conducted by EIG and its affiliates. The disclosure does not relate to any activities conducted by us or by WP and does not involve our or WP's management. Neither we nor WP has had any involvement in or control over the disclosed activities of EIG, and neither we nor WP has independently verified or participated in the preparation of the disclosure. Neither we 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.

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

> "Our business activities are subject to various restrictions under U.S. export controls and trade and economic sanctions laws, including the U.S. Commerce Department's Export Administration Regulations and economic and trade sanctions regulations maintained by the U.S. Treasury Department's Office of Foreign Assets Control, or OFAC. If we fail to comply with these laws and regulations, we could be subject to civil or criminal penalties and reputational harm. In addition, if our third-party resellers fail to comply with these laws and regulations in their dealings, we could face potential liability or penalties for violations. Furthermore, U.S. export control laws and economic sanctions laws prohibit certain transactions with U.S. embargoed or sanctioned countries, governments, persons and entities.
>
> Although we take precautions to prevent transactions with U.S. sanctions targets, we have in the past identified limited instances of non-compliance with these rules and believe we have taken appropriate corrective actions in such instances. For example, on May 1, 2013, during a routine compliance scan of our new and existing subscriber accounts, we discovered a new subscriber account that was created on April 6, 2013 with information matching ORT France, identified by OFAC as a Specially Designated National, or SDN, under the Global Terrorism Sanctions Regulations, 31 C.F.R. Part 594. We had charged the subscriber $114.10 for web hosting and domain name registration services at the time the account was opened and without knowledge of any SDN issue. Upon discovery of the potential SDN match, we promptly suspended the subscriber account, deactivated the website, locked the domain name to prevent it from being transferred and ceased providing services to the subscriber. We also promptly reported the potential SDN match to OFAC. To date, we have not received any correspondence from OFAC regarding the matter.
>
> Although we have implemented compliance measures that are designed to prevent transactions with U.S. sanction targets, there is risk that in the future we or our resellers could provide our solutions or services to such targets despite such compliance measures. This could result in negative consequences to us, including government investigations, penalties and reputational harm.
>
> Changes in our solutions or changes in export and import regulations may create delays in the introduction and sale of our solutions in international markets, prevent our subscribers with international operations from deploying our solutions or, in some cases, prevent the export or import of our solutions to certain countries, governments or persons altogether. Any change in export or import regulations, shift in the enforcement or scope of existing regulations, or change in the countries, governments, persons or technologies targeted by such regulations, could result in decreased use of our solutions or decreased ability to export or sell our solutions to existing or potential subscribers with international operations. Any decreased use of our solutions or limitation on our ability to export or sell our solutions could adversely affect our business, financial condition and operating results."

SAMIH

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

We understand that SAMIH's affiliates intend to disclose in their next annual or quarterly SEC report that an Iranian national, resident in the U.K., who is currently designated by the U.S. and the U.K. under the Iran Sanctions regime, holds two investment accounts with Santander Asset Management UK Limited, a subsidiary of SAMIH and part of the Banco Santander group. The accounts have remained frozen throughout 2013. The investment returns are being automatically reinvested, and no disbursements have been made to the customer. Total revenue in connection with the investment accounts in 2013 was £247 and net profits in 2013 were negligible relative to the overall profits of Banco Santander, S.A.

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 2014 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, 2013.

Name	Age	Title
Peter R. Kagan	45	Director
W. Howard Keenan, Jr.	63	Director
Christopher R. Manning	46	Director
Richard W. Connor	64	Director
Robert J. Clark	68	Director
Benjamin A. Hardesty	64	Director
James R. Levy	37	Director
Paul M. Rady	60	Chairman of the Board of Directors and Chief Executive Officer
Glen C. Warren, Jr.	57	Director, President, Chief Financial Officer and Secretary
Kevin J. Kilstrom	59	Vice President—Production
Alvyn A. Schopp	55	Chief Administrative Officer and Regional Vice President
Ward D. McNeilly	63	Vice President—Reserves, Planning and Midstream

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

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. 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 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 currently serves on the Board of Directors of GeoMet, Inc. 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. 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 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, VantaCore Partners and Velvet Energy, Ltd. 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 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 and a member of our audit and compensation committees 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 and member of our compensation and nominating and governance committees since our initial public offering in October 2013. 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. In 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 Blue Dot Energy Services LLC from 2011 until its recent sale to B/E Aerospace. From 1982 to 1995, Mr. Hardesty served successively as vice president, executive vice president and president of Stonewall Gas Company, and from 1978 to 1982, he served as vice president—operations of Development Drilling Corp. Mr. Hardesty received his Bachelor of Science degree from West Virginia University and his Master of Science—Management 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 College of Engineering and Mineral Resources at West Virginia University.

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 Black Swan Energy, Brigham Resources and Brigham Minerals, EnStorage, Hawkwood Energy, Laredo Petroleum and Suniva. 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.

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. 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. 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.

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 20,2013, 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.

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 2014 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 2014 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 2014 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 2014 Annual Meeting of Stockholders.

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 Exhibits
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.
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.
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.
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.

Exhibit Number	Description of Exhibits
4.7	Registration Rights Agreement 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 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 August 1, 2011).
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.
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.
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.
4.13	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).
4.14	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).
4.15	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).
4.16	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).
4.17*	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.

Exhibit Number	Description of Exhibits
4.18	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).
4.19	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).
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 310.4 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 Form 10-Q (Commission File No. 333-164876) filed on May 16, 2011).

Exhibit Number	Description of Exhibits
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).

Exhibit Number	Description of Exhibits
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	Purchase Agreement dated as of November 14, 2012 by and among Antero Resources Finance Corporation, the guarantors party thereto and Wells Fargo Securities LLC as representative of the initial purchasers named therein (incorporated by reference to Exhibit 10.1 to Current Report on Form 8-K (Commission File No. 333-164876) filed on November 20, 2012).
10.17	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).
10.18	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).
10.19	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).
10.20	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.
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).

Exhibit Number	Description of Exhibits
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 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).
99.2	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).
99.3	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).
99.4	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).
99.5	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).
99.6	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).
99.7	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).
99.8	Report of DeGolyer and MacNaughton for reserves as of December 31, 2011 relating to Appalachian Basin properties (incorporated by reference to Exhibit 99.1 to Annual Report on Form 10-K (Commission File No. 333-164876) filed on March 20, 2012).
99.9	Report of DeGolyer and MacNaughton for reserves as of December 31, 2011 relating to Arkoma Basin, Woodford Shale and Fayetteville Shale properties (incorporated by reference to Exhibit 99.2 to Annual Report on Form 10-K (Commission File No. 333-164876) filed on March 20, 2012).
99.10	Report of Ryder Scott Company, L.P. for reserves as of December 31, 2011 relating to Piceance Basin properties (incorporated by reference to Exhibit 99.3 to Annual Report on Form 10-K (Commission File No. 333-164876) filed on March 20, 2012).

Exhibit Number	Description of Exhibits
101*	The following financial information from this Form 10-K of Antero Resources Corporation for the year ended December 31, 2013, 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 (in the case of Exhibits 32.1 and 32.2) with this Annual Report on Form 10-K.

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 27, 2014

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 27, 2014
/s/ GLEN C. WARREN, JR. Glen C. Warren, Jr.	Director, President, Chief Financial Officer and Secretary (principal financial officer)	February 27, 2014
/s/ K. PHIL YOO K. Phil Yoo	Chief Accounting Officer and Corporate Controller (principal accounting officer)	February 27, 2014
/s/ ROBERT J. CLARK Robert J. Clark	Director	February 27, 2014
/s/ RICHARD W. CONNOR Richard W. Connor	Director	February 27, 2014
/s/ BENJAMIN A. HARDESTY Benjamin A. Hardesty	Director	February 27, 2014
/s/ PETER R. KAGAN Peter R. Kagan	Director	February 27, 2014

Signature	Title	Date
/s/ HOWARD KEENAN, JR. W. Howard Keenan, Jr.	Director	February 27, 2014
/s/ JAMES R. LEVY	Director	February 27, 2014
/s/ CHRISTOPHER R. MANNING Christopher R. Manning	Director	February 27, 2014

SUBSIDIARIES OF ANTERO RESOURCES CORPORATION Name of Subsidiary	Jurisdiction of Organization
Antero Resources Midstream LLC	Delaware
Antero Resources Midstream Operating LLC	Delaware

INDEX TO FINANCIAL STATEMENTS

Introductory Note to Financial Statements

The historical consolidated financial statements of Antero Resources Corporation presented herein include the accounts of Antero Resources LLC and its direct or indirect wholly owned subsidiaries, Antero Resources Corporation (successor to Antero Resources Appalachian Corporation), Antero Resources Bluestone LLC, and Antero Resources Finance Corporation. Antero Resources Piceance LLC (successor to Antero Resources Piceance Corporation), which owned the Piceance Basin assets along with Antero Resources Pipeline LLC (successor to Antero Resources Pipeline Corporation), and Antero Resources Arkoma LLC (successor to Antero Resources Corporation), which owned the Arkoma Basin assets, were merged into Antero Resources Appalachian Corporation in February 2013. Antero Resources Appalachian Corporation then changed its name to Antero Resources Corporation. Antero Resources LLC had no assets other than its investment in Antero Resources Corporation and was merged into Antero Resources Corporation upon the completion of a public offering in October 2013. Antero Resources Finance Corporation and Antero Resources Bluestone LLC were merged into Antero Resources Corporation in December 2013. The financial statements of Antero Resources LLC and Antero Resources Corporation continue to be identical with respect to the underlying financial information at such time.

Antero Resources LLC and Antero Resources Corporation filed separate federal and state income tax returns; Antero Resources LLC was not subject to income taxes because it was a pass-through entity for federal and state tax purposes. Antero Resources Corporation has provided for income taxes in its financial statements and its income tax provisions and liabilities did not change as a result of the merger of Antero Resources LLC and Antero Resources Corporation upon the completion of the public offering.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors
Antero Resources Corporation:

We have audited the accompanying consolidated balance sheets of Antero Resources Corporation and subsidiary as of December 31, 2012 and 2013, 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, 2013. 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 subsidiary as of December 31, 2012 and 2013, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2013, in conformity with U.S. generally accepted accounting principles.

/s/ KPMG LLP

Denver, Colorado
February 27, 2014

ANTERO RESOURCES CORPORATION

Consolidated Balance Sheets

December 31, 2012 and 2013

(In thousands)

	2012	2013
Assets		
Current assets:		
Cash and cash equivalents	$ 18,989	$ 17,487
Accounts receivable—trade, net of allowance for doubtful accounts of $174 and $1,251 in 2012 and 2013, respectively	21,296	30,610
Notes receivable—short-term portion	4,555	2,667
Accrued revenue	46,669	96,825
Derivative instruments	160,579	183,000
Other	22,518	2,975
Total current assets	274,606	333,564
Property and equipment:		
Natural gas properties, at cost (successful efforts method):		
Unproved properties	1,243,237	1,513,136
Proved properties	1,682,297	3,621,672
Fresh water distribution systems	6,835	231,684
Gathering systems and facilities	168,930	584,626
Other property and equipment	9,517	15,757
	3,110,816	5,966,875
Less accumulated depletion, depreciation, and amortization	(173,343)	(407,219)
Property and equipment, net	2,937,473	5,559,656
Derivative instruments	371,436	677,780
Notes receivable—long-term portion	2,667	—
Other assets, net	32,611	42,581
Total assets	$3,618,793	$6,613,581
Liabilities and Equity		
Current liabilities:		
Accounts payable	$ 181,478	$ 370,640
Accrued liabilities	58,829	77,126
Revenue distributions payable	46,037	96,589
Current debt	25,000	—
Deferred income tax liability	62,620	69,191
Derivative instruments	—	646
Other	2,332	8,037
Total current liabilities	376,296	622,229
Long-term liabilities:		
Long-term debt	1,444,058	2,078,999
Deferred income tax liability	91,692	278,580
Other long-term liabilities	33,010	35,113
Total liabilities	1,945,056	3,014,921
Stockholders'/Members' Equity:		
Members' equity of Antero Resources LLC	1,460,947	—
Common stock of Antero Resources Corporation, $0.01 par value; authorized—1,000,000,000 shares; issued and outstanding 262,049,659 shares	—	2,620
Preferred stock of Antero Resources Corporation, $0.01 par value; authorized—50,000,000 shares; none issued	—	—
Additional paid-in capital	—	3,402,180
Accumulated earnings	212,790	193,860
Total equity	1,673,737	3,598,660
Total liabilities and equity	$3,618,793	$6,613,581

See accompanying notes to consolidated financial statements.

ANTERO RESOURCES CORPORATION

Consolidated Statements of Operations and Comprehensive Income (Loss)

Years Ended December 31, 2011, 2012 and 2013

(In thousands, except per share amounts)

	2011	2012	2013
Revenue:			
Natural gas sales	$ 195,116	$ 259,743	$ 689,198
Natural gas liquids sales	—	3,719	111,663
Oil sales	173	1,520	20,584
Commodity derivative fair value gains	496,064	179,546	491,689
Gain on sale of gathering system	—	291,190	—
Total revenue	691,353	735,718	1,313,134
Operating expenses:			
Lease operating	4,608	6,243	9,439
Gathering, compression, processing, and transportation	37,315	91,094	218,428
Production and ad valorem taxes	11,915	20,210	50,481
Exploration	4,034	14,675	22,272
Impairment of unproved properties	4,664	12,070	10,928
Depletion, depreciation, and amortization	55,716	102,026	233,876
Accretion of asset retirement obligations	76	101	1,065
General and administrative (including $365,280 of stock compensation in 2013)	33,342	45,284	425,438
Loss on sale of assets	8,700	—	—
Total operating expenses	160,370	291,703	971,927
Operating income	530,983	444,015	341,207
Other expenses:			
Interest	(74,404)	(97,510)	(136,617)
Loss on early extinguishment of debt	—	—	(42,567)
Interest rate derivative fair value loss	(94)		
Total other expenses	(74,498)	(97,510)	(179,184)
Income from continuing operations before income taxes and discontinued operations	456,485	346,505	162,023
Provision for income taxes	(185,297)	(121,229)	(186,210)
Income from continuing operations	271,188	225,276	(24,187)
Discontinued operations:			
Income (loss) from results of operations and sale of discontinued operations, net of income tax (expense) benefit of $(45,155), $272,533, and $(3,249) in 2011, 2012, and 2013, respectively	121,490	(510,345)	5,257
Net income (loss) and comprehensive income (loss)	$ 392,678	$(285,069)	$ (18,930)
Earnings (loss) per share:			
Continuing operations	$ 1.04	$ 0.86	$ (0.09)
Discontinued operations	$ 0.46	$ (1.95)	$ 0.02
Total	$ 1.50	$ (1.09)	$ (0.07)
Earnings (loss) per share—assuming dilution:			
Continuing operations	$ 1.04	$ 0.86	$ (0.09)
Discontinued operations	$ 0.46	$ (1.95)	$ 0.02
Total	$ 1.50	$ (1.09)	$ (0.07)

See accompanying notes to consolidated financial statements.

ANTERO RESOURCES CORPORATION

Consolidated Statements of Equity

Years ended December 31, 2011, 2012, and 2013

(In thousands)

	Members' equity	Common Stock	Additional paid-in capital	Accumulated earnings	Total equity
Balances, December 31, 2010	$ 1,489,806	—	—	105,181	$1,594,987
Distribution to members	(28,859)	—	—	—	(28,859)
Net income and comprehensive income	—	—	—	392,678	392,678
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
Capital contribution for stock compensation of affiliate	—	—	364,957	—	364,957
Stock compensation related to Company plan	—	—	323	—	323
Net loss and comprehensive loss	—	—	—	(18,930)	(18,930)
Balances, December 31, 2013	$ —	2,620	3,402,180	193,860	$3,598,660

ANTERO RESOURCES CORPORATION

Consolidated Statements of Cash Flows

Years ended December 31, 2011, 2012, and 2013

(In thousands)

	2011	2012	2013
Cash flows from operating activities:			
Net income (loss)	$ 392,678	$ (285,069)	$ (18,930)
Adjustment to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation, amortization, and depletion	55,792	102,127	234,941
Impairment of unproved properties	4,664	12,070	10,928
Derivative fair value gains	(495,970)	(179,546)	(491,689)
Cash receipts for settled derivatives	45,638	178,491	163,570
Deferred income taxes	185,297	106,229	190,210
Loss (gain) on sale of assets	8,700	(291,190)	—
Stock compensation	—	—	365,280
Loss on early extinguishment of debt	—	—	42,567
Loss (gain) on sale of discontinued operations		795,945	(8,506)
Depletion, depreciation, amortization, and impairment of unproved properties—discontinued operations	126,041	90,096	—
Derivative fair value gains—discontinued operations	(180,130)	(46,358)	—
Cash receipts for settled derivatives—discontinued operations	66,654	92,166	—
Deferred income taxes—discontinued operations	45,155	(272,553)	3,249
Other	3,479	4,960	1,173
Changes in assets and liabilities:			
Accounts receivable	3,854	5,511	(9,314)
Accrued revenue	(11,118)	(10,683)	(50,156)
Other current assets	(4,528)	(8,882)	19,543
Accounts payable	(1,875)	(2,117)	1,039
Accrued liabilities	17,124	14,790	26,803
Revenue distributions payable	4,852	11,268	50,552
Other	—	15,000	3,447
Net cash provided by operating activities	266,307	332,255	534,707
Cash flows from investing activities:			
Additions to proved properties	(105,405)	(10,254)	(15,300)
Additions to unproved properties	(195,131)	(687,403)	(440,825)
Drilling and completion costs	(527,710)	(836,350)	(1,615,965)
Additions to fresh water distribution systems	—	(2,801)	(203,790)
Additions to gathering systems and facilities	(72,837)	(142,294)	(389,453)
Additions to other property and equipment	(2,339)	(3,447)	(6,240)
(Increase) decrease in notes receivable	(10,111)	4,889	4,555
Increase in other assets	(3,095)	(3,707)	(6,574)
Proceeds from asset sales	15,379	1,217,876	—
Net cash used in investing activities	(901,249)	(463,491)	(2,673,592)
Cash flows from financing activities:			
Issuance of common stock	—	—	1,578,573
Issuance of senior notes	400,000	300,000	1,231,750
Repayment of senior notes	—	—	(690,000)
Borrowings (repayments) on bank credit facility, net	265,000	(148,000)	71,000
Payments of deferred financing costs and loss on extinguishment of debt	(6,691)	(5,926)	(53,940)
Distribution to members	(28,859)	—	—
Other	(153)	808	—
Net cash provided by financing activities	629,297	146,882	2,137,383
Net increase (decrease) in cash and cash equivalents	(5,645)	15,646	(1,502)
Cash and cash equivalents, beginning of period	8,988	3,343	18,989
Cash and cash equivalents, end of period	$ 3,343	$ 18,989	$ 17,487
Supplemental disclosure of cash flow information:			
Cash paid during the period for interest	$ 59,107	$ 90,122	$ 117,832
Supplemental disclosure of noncash investing activities:			
Changes in accounts payable for additions to property and equipment	$ 26,465	$ 72,881	$ 188,123

See accompanying notes to consolidated financial statements.

(1) Organization

(a) Business and Organization

Antero Resources Corporation and its consolidated subsidiary (collectively referred to as the "Company," "we," or "our") 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. We target 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. During 2012 we sold our Oklahoma Arkoma Basin properties and our Colorado Piceance Basin properties. We also have midstream gathering and water distribution operations in the Appalachian Basin. Our corporate headquarters are in Denver, Colorado.

Our consolidated financial statements as of December 31, 2013 include the accounts of Antero Resources Corporation and its subsidiary, Antero Resources Midstream LLC.

(b) Corporate Reorganization and Initial Public Offering (IPO)

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 our 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 an IPO resulting in proceeds to the Company, net of underwriter discounts and expenses of the offering, of approximately $1.6 billion. Antero Investment also sold 3,409,091 shares of its common stock of Antero Resources Corporation in the IPO. The Company did not receive any of the proceeds from the sale of the shares by Antero Investment.

In 2013, the Company formed a subsidiary, Antero Resources Midstream LLC ("Antero Midstream"). The Company owns all of the membership interests in Antero Midstream other than a special membership interest which is indirectly owned by Antero Investment. In connection with an initial public offering of Antero Midstream during 2014, the Company intends to contribute its midstream assets to Antero Midstream and enter into commercial arrangements for midstream services. The assets to be contributed consist of (i) low- and high-pressure natural gas gathering lines, (ii) fresh water distribution systems and (iii) compression facilities. The special membership interest in Antero Midstream provides Antero Investment with certain rights, including the right to cause an initial public offering of Antero Midstream as a master limited partnership ("MLP") or similar structure. Following any such initial public offering, the special membership interest will entitle Antero Investment to the general partner interest in the MLP, which will allow Antero Investment to manage Antero Midstream's business and affairs. Following any such initial public offering, Antero Investment will also hold

(1) Organization (Continued)

incentive distribution rights in the MLP, which will represent the right to receive an increasing percentage of the MLP's quarterly cash distributions in excess of specified target distribution levels.

(c) Stock Compensation Charge in Connection with the Reorganization

In connection with the formation of Antero Resources LLC in October 2009, Antero Resources LLC issued profits interests to Antero Resources Employee Holdings LLC ("Employee Holdings"), which is owned solely by certain of our 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 our officers and employees. The Employee Holdings interests in Antero Resources LLC were exchanged for similar interests in Antero Investment on October 16, 2013.

The limited liability company agreement of Antero Investment provides a mechanism by which the shares of the Company's common stock to be allocated among the members of Antero Investment, including Employee Holdings, will be determined. As a result of the adoption of the Antero Investment LLC 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, we recognized approximately $365 million of stock compensation expense for the vested profits interests through December 31, 2013 and will recognize an additional approximate $121 million over the remaining service period. Because consideration for the profits interests awards will be deemed given by Antero Investment, the charge to stock compensation expense is accounted for as a capital contribution by Antero Investment in the Company and credited to additional paid-in capital.

(2) Summary of Significant Accounting Policies

(a) Basis of Presentation

The accompanying consolidated financial statements include the accounts of Antero Resources Corporation and its subsidiary. All significant intercompany accounts and transactions have been eliminated.

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.

(b) Use of Estimates

The preparation of consolidated financial statements in conformity with generally accepted accounting principles in the United States 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

(2) Summary of Significant Accounting Policies (Continued)

depreciation, depletion, amortization, present value of cash flows from reserves, and impairment of oil and gas properties. Reserve estimates by their nature are inherently imprecise.

(c) Risks and Uncertainties

Historically, the market for natural gas, NGLs, and oil has experienced significant price fluctuations. Prices for natural gas have been particularly volatile in recent years. The 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 prices received could have a significant impact on the Company's future results of operations.

(d) 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.

(e) 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, costs of productive wells, development dry holes, 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 well is determined not to have found reserves in commercial 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. 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 recognizing 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 $11.1 million, $13.0 million, and $10.9 million for the years ended December 31, 2011, 2012, and 2013, 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

(2) Summary of Significant Accounting Policies (Continued)

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, cash flow from commodity hedges, 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, 2011, 2012, and 2013.

At December 31, 2013, 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 proved reserves at December 31, 2013.

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 $164.0 million, $181.7 million, and $219.8 million for the years ended December 31, 2011, 2012, and 2013, respectively.

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

Gathering pipelines and compressor stations are depreciated using the straight-line method over their estimated useful life of 20 years. Fresh water distribution systems are depreciated over useful lives of from 5 to 20 years. Expenditures for installation, major additions, and improvements are capitalized, and minor replacements, maintenance, and repairs are charged to expenses as incurred. For the years ended December 31, 2011, 2012, and 2013, depreciation expense for gathering pipelines, compressor stations, and fresh water distribution systems was $5.5 million, $7.4 million, and $11.9 million, respectively. A gain or loss is recognized upon the sale or disposal of property and equipment.

(g) 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 amount 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 value amounts of the assets are deemed to be not recoverable, the carrying amount is 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, 2013.

(h) Other Property and Equipment

Other property and equipment is depreciated using the straight-line method over estimated useful lives ranging from three to five years. For the years ended December 31, 2011, 2012, and 2013, depreciation expense for other property and equipment was $1.0 million, $1.7 million, and $2.2 million, respectively. A gain or loss is recognized upon the sale or disposal of property and equipment.

(2) Summary of Significant Accounting Policies (Continued)

(i) 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 being amortized over the term of the related debt using the effective interest method. The Company charges interest expense for deferred financing costs remaining for debt facilities that have been retired prior to their maturity date. At December 31, 2013, the Company had $28 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 $3.8 million, $5.2 million, and $15.8 million for the years ended December 31, 2011, 2012, and 2013, respectively.

(j) Derivative Financial Instruments

In order to manage its exposure to oil and gas price volatility, the Company enters into derivative transactions from time to time, including commodity swap agreements, collar agreements, and other similar agreements relating to natural gas expected to be produced. To the extent legal right of offset with a counterparty exists, 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, and changes in the fair value of interest rate derivatives are classified as other income (expense).

(k) 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 life. 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, revisions to estimated inflation and interest rates, 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 we operate will cease. In the absence of such information, we are not able to make a

(2) Summary of Significant Accounting Policies (Continued)

reasonable estimate of when future dismantlement and removal dates will occur and therefore have not recorded asset retirement obligations related to gathering assets.

(l) 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, 2012 and 2013, the Company has not accrued a material amount for any environmental liabilities nor has it been fined or cited for any environmental violations that could have a material adverse effect on future capital expenditures or operating results of the Company.

(m) Natural Gas, NGL 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 revenue distribution payable to the extent it receives more than its proportionate share natural gas revenues. At December 31, 2012 and 2013, the Company had no significant imbalance positions.

(n) 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, 2011, 2012, and 2013 are as follows (including sales in discontinued operations):

	2011	2012	2013
Company A	28%	23%	30%
Company B	17	13	14
Company C	12	10	8
All others	43	54	48
	100%	100%	100%

(2) Summary of Significant Accounting Policies (Continued)

Although a substantial portion of 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 other customers or markets would be accessible to us.

The Company is also exposed to credit risk on its commodity derivative portfolio. 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 of approximately $860 million at December 31, 2013 includes the following values by bank counterparty: BNP Paribas—$197 million; Credit Suisse—$190 million; Barclays—$147 million; Wells Fargo—$140 million; JP Morgan—$134 million; Citigroup—$34 million; Deutsche Bank—$15 million; and Toronto Dominion Bank—$3 million. 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 at December 31, 2013 for each of the European and American banks. We believe that all of these institutions currently are acceptable credit risks.

The Company, at times, may have cash in banks in excess of federally insured amounts.

(o) Income Taxes

The Company recognizes deferred tax assets and liabilities for temporary differences resulting from net operating loss carryforwards for income tax purposes and the differences between the financial statement and tax basis of assets and liabilities. The effect of changes in the tax laws or tax rates is recognized in income in the period such changes are enacted. Deferred tax assets are reduced by a valuation allowance, when, in the opinion of management, it is more likely than not that some portion or all of the deferred tax assets will not be realized.

Unrecognized tax benefits represent potential future tax obligations for uncertain tax positions taken on previously filed tax returns that may not ultimately be sustained. The Company recognizes interest expense related to unrecognized tax benefits in interest expense and fines and penalties as income tax expense.

(p) Fair Value Measures

FASB ASC Topic 820, *Fair Value Measurements and Disclosures*, clarifies the definition of fair value, establishes a framework for measuring fair value, and expands disclosures about fair value measurements. This guidance also relates to all nonfinancial assets and liabilities that are not recognized or disclosed on a recurring basis (e.g., those measured at fair value in a business combination, the initial recognition of asset retirement obligations, and impairments of proved oil and gas properties, and other long-lived assets). The fair value is the price that the Company estimates would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. A fair value hierarchy is used to prioritize input to valuation techniques used to estimate fair value. An asset or liability subject to the fair value requirements is categorized within the hierarchy based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement in its entirety requires judgment and considers factors specific to the asset or liability. The highest priority (Level 1) is given to unadjusted quoted market prices in active markets

(2) Summary of Significant Accounting Policies (Continued)

for identical assets or liabilities, and the lowest priority (Level 3) is given to unobservable inputs. Level 2 inputs are data, other than quoted prices included within Level 1 that are observable for the asset or liability, either directly or indirectly. Instruments which are valued using Level 2 inputs include nonexchange traded derivatives such as over-the-counter commodity price swaps, basis swaps, and interest rate swaps. Valuation models used to measure fair value of these instruments consider various Level 2 inputs including (i) quoted forward prices for commodities, (ii) time value, (iii) quoted forward interest rates, (iv) current market prices and contractual prices for the underlying instruments, (v) risk of nonperformance by the Company and the counterparty, and (vi) other relevant economic measures. To the extent a legal right of offset with a counterparty exists, the derivative assets and liabilities are reported on a net basis.

(q) Industry Segment and Geographic Information

We have evaluated how the Company is organized and managed and have identified the following operating segments: (1) the exploration and production of oil, natural gas, and natural gas liquids, and (2) midstream operations consisting of natural gas gathering, compression, and fresh water distribution operations for the distribution of fresh water used in well completions. Prior to 2013, the Company did not have any reportable segments and considered its gathering, compression, and fresh water distribution operations to be ancillary to its exploration and production activities. In connection with the proposed initial public offering of Antero Midstream, the Company intends to contribute its midstream assets to Antero Midstream. Antero Midstream is expected to enter into agreements with the Company for the dedication of substantially all of the Company's current and future acreage for natural gas gathering and compression services and for fresh water sourcing and delivery related to all of the Company's current and future drilling. The Company intends to convert Antero Midstream into a limited partnership in connection with a public offering of Antero Midstream as a master limited partnership. As a result of these transactions, management has begun to evaluate these gathering and compression and fresh water distribution services separately from exploration and production activities and these operations therefore became reportable segments as of December 31, 2013. Prior to 2013 and the planned master limited partnership, gathering and compression and fresh water distribution services were not material.

All of our assets are located in the United States and all of our revenues are attributable to customers located in the United States.

(r) Reclassifications

Certain reclassifications have been made to prior periods' financial information related to water distribution assets to conform to the 2013 presentation.

(s) Earnings (loss) per share.

Earnings (loss) per common share and earnings (loss) per common share—assuming dilution for each of the three years ended December 31, 2013 was calculated as if the shares issued in the Corporate Reorganization and IPO described in Note 1 were outstanding for the entire period. The effect of dilutive options and restricted stock awards in 2013 is less than $0.01 per share.

(3) Sale of Piceance and Arkoma Properties—Discontinued Operations

On December 21, 2012 the Company completed the sale of its Piceance Basin assets in Colorado. Proceeds from the sale of $316 million represent the purchase price of $325 million, adjusted for expenses of the sale and estimated income, expenses, and capital costs related to the Piceance Basin properties from the October 1, 2012 effective date of the sale through December 21, 2012 (the interim period). The purchaser also assumed all of the Company's Rocky Mountain firm transportation obligations. Because of the sale of the Piceance Basin assets, the Company also liquidated its hedge positions related to the Piceance Basin and realized additional proceeds from these transactions of approximately $100 million. The loss on the sale of the Piceance Basin assets was adjusted downward by $8.5 million in 2013 as a result of the resolution of certain liabilities recorded at the time of the sale and the settlement of final purchase price adjustments.

On June 29, 2012 the Company completed its sale of its Arkoma Basin assets in Oklahoma and the commodity hedges associated with the Arkoma assets. Proceeds from the sale of $427 million represent the purchase price of $445 million adjusted for expenses of the sale and estimated income, expenses, and capital costs from the effective date of the sale through the closing date of June 29, 2012. The Company recorded a loss of $432 million on the sale of the Arkoma Basin assets. The Company's Arkoma Basin midstream operations, which were sold on November 5, 2010, are also included in discontinued operations through the date of the sale. The Company realized a gain in 2010 of $148 million on the sale of those midstream operations.

Results of operations and the loss on the sale of the Piceance Basin and Arkoma Basin assets are shown as discontinued operations on the accompanying Consolidated Statement of Operations and Comprehensive Income (Loss) and are comprised of the following (in thousands):

	Year ended December 31		
	2011	2012	2013
Sales of oil, natural gas, and natural gas liquids	$196,705	$ 125,396	$ —
Commodity derivative fair value gains	180,130	46,358	—
Total revenues	376,835	171,754	—
Lease operating	26,037	19,901	—
Gathering, compression, and transportation	50,453	45,089	—
Production taxes	6,307	2,967	—
Exploration	5,842	664	—
Impairment of unproved properties	6,387	962	—
Depletion, depreciation, and amortization	114,805	88,720	—
Accretion of asset retirement obligations	359	404	—
Loss on sale of assets	—	795,945	(8,506)
Total expenses	210,190	954,652	(8,506)
Income (loss) from discontinued operations before income taxes	166,645	(782,898)	8,506
Income tax (expense) benefit	(45,155)	272,553	(3,249)
Net income (loss) from discontinued operations	$121,490	$(510,345)	$ 5,257

(4) Sale of Appalachian Gathering Assets

On March 26, 2012, the Company closed the sale of a portion of its Marcellus Shale gathering system assets in West Virginia along with exclusive rights to gather the Company's 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 (subject to customary purchase price adjustments). The sale included approximately 25 miles of low pressure pipeline systems and gathering rights on 104,000 net acres held by the Company within a 250,000 acre AOD and had an effective date of January 1, 2012. Other third-party producers will also have access to the Crestwood system. During the first seven years of the contract, the Company is committed to deliver minimum annual volumes into the gathering systems, with certain carryback and carryforward adjustments for overages or deficiencies. The Company can earn up to an additional $40 million of sale proceeds over the next three years if it meets certain volume thresholds, but has not recorded any part of these contingent proceeds at December 31, 2013. Crestwood is obligated to incur all future capital costs to build out gathering systems and compression facilities within the AOD to connect the Company's wells as it executes its drilling program and has assumed the various risks and rewards of the system build-out and operations. Because the Company has not retained the substantial risks and rewards of ownership associated with the gathering rights and systems transferred to Crestwood, it has recognized a gain on the sale of the gathering system and gathering rights of approximately $291 million.

(5) Notes Receivable

At December 31, 2012 and 2013 the Company had notes receivable from a drilling contractor of $7.2 million and $2.7 million, respectively. The notes result from the Company's advances to the drilling contractor to construct drilling rigs to be used by the contractor to fulfill long-term drilling contracts with the Company. The notes are noninterest bearing and are repayable over the term of the service agreements with the drilling contractor.

(6) Long-Term Debt

The Company's had long-term debt as follows at December 31, 2012 and 2013 (in thousands):

	2012	2013
Bank credit facility[a]	$ 217,000	$ 288,000
9.375% senior notes due 2017[b]	525,000	—
7.25% senior notes due 2019[c]	400,000	260,000
6.00% senior notes due 2020[d]	300,000	525,000
5.375% senior notes due 2021[e]	—	1,000,000
9.00% senior note due 2013[f]	25,000	—
Net unamortized premium	2,058	5,999
	1,469,058	2,078,999
Less amounts due within one year	25,000	—
	$1,444,058	$2,078,999

(6) Long-Term Debt (Continued)

(a) Senior Secured Revolving Credit Facility

The Company has a senior secured revolving bank credit facility (the Credit Facility) with a consortium of bank lenders. The maximum amount of the Credit Facility is $2.5 billion. Borrowings under the Credit Facility are subject to borrowing base limitations based on the collateral value of our proved properties and commodity hedge positions and are subject to regular semiannual redeterminations. At December 31, 2013, the borrowing base was $2.0 billion and lender commitments were $1.5 billion. Lender commitments can be increased to the full amount of the borrowing base upon approval of the lending group. The next redetermination of the borrowing base is scheduled to occur in April 2014. The Credit Facility matures on May 12, 2016.

The Credit Facility is secured by mortgages on substantially all of the Company's properties and guarantees from the Company's subsidiary. The Credit Facility contains certain covenants, including restrictions on indebtedness and dividends, and requirements with respect to working capital and interest coverage ratios. Interest is payable at a variable rate based on LIBOR or the prime rate based on the Company's election at the time of borrowing. The Company was in compliance with all of the financial covenants under the Credit Facility as of December 31, 2012 and 2013.

As of December 31, 2013, the Company had an outstanding balance under the Credit Facility of $288 million, with a weighted average interest rate of 1.61%, and outstanding letters of credit of $32 million. As of December 31, 2012, the Company had an outstanding balance under the Credit Facility of $217 million, with a weighted average interest rate of 1.91%, and outstanding letters of credit of approximately $43 million. Commitment fees on the unused portion of the Credit Facility are due quarterly at rates ranging from 0.375% to 0.50% of the unused facility based on utilization.

(b) Redemption of 9.375% Senior Notes

On December 2, 2013, the Company redeemed the 9.375% senior notes due in 2017 out of the proceeds from the issuance of the 5.375% senior notes due 2021. The notes were redeemed at a price of 104.688% and the resulting premium of $24.6 million was charged to Loss on Early Extinguishment of Debt, which is included in Other Expenses in the accompanying Statement of Operations. Additionally, $5.9 million of deferred financing costs, net of unamortized premium, was charged to Loss on Early Extinguishment of Debt.

(c) 7.25% Senior Notes Due 2019

On August 1, 2011, the Company issued $400 million of 7.25% senior notes due August 1, 2019 at par. The notes are unsecured and effectively subordinated to the Company's Credit Facility to the extent of the value of the collateral securing the Credit Facility. The notes are guaranteed on a senior unsecured basis by Antero Midstream, Antero Resources Midstream Operating ("Midstream Operating") and certain of our future restricted subsidiaries. Interest on the notes is payable on August 1 and February 1 of each year. The Company may redeem all or part of the notes at any time on or after August 1, 2014 at redemption prices ranging from 105.438% on or after August 1, 2014 to 100.00% on or after August 1, 2017. At any time prior to August 1, 2014, the Company may redeem the notes, in whole or in part, at a price equal to 100% of the principal amount of the notes plus a "make-whole" premium and accrued interest. If the Company undergoes a change of control, the note

(6) Long-Term Debt (Continued)

holders will have the right to require the Company to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the notes, plus accrued interest.

On November 25, 2013, the Company redeemed $140 million of the 7.25% senior notes out of the proceeds from the public stock offering completed on October 16, 2013. The notes were redeemed at a price of 107.25% and the resulting premium of $10.2 million was charged to Loss on Early Extinguishment of Debt, which is included in Other Expense in the accompanying Statement of Operations. Additionally, $1.9 million of deferred financing costs was charged to Loss on Early Extinguishment of Debt.

(d) 6.00% Senior Notes Due 2020

On November 19, 2012, the Company issued $300 million of 6.00% senior notes due December 1, 2020 at par. After December 31, 2012, on February 4, 2013 the Company issued an additional $225 million of the 6.00% notes at 103% of par. The notes are unsecured and effectively subordinated to the Company's Credit Facility to the extent of the value of the collateral securing the Credit Facility. The notes rank pari passu to the existing 5.375% and 7.25% senior notes. The notes are guaranteed on a senior unsecured basis by Antero Midstream, Midstream Operating and certain of our future restricted subsidiaries. Interest on the notes is payable on June 1 and December 1 of each year, commencing on June 1, 2013. The Company may redeem all or part of the notes at any time on or after December 1, 2015 at redemption prices ranging from 104.500% on or after December 1, 2015 to 100.00% on or after December 1, 2018. In addition, on or before December 1, 2015, the Company may redeem up to 35% of the aggregate principal amount of the 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 notes, plus accrued interest. At any time prior to December 1, 2015, the Company may redeem the notes, in whole or in part, at a price equal to 100% of the principal amount of the notes plus a "make-whole" premium and accrued interest. If a change of control (as defined in the bond indenture) occurs at any time prior to January 1, 2014, the Company may, at its option, redeem all, but not less than all, of the notes at a redemption price equal to 110% of the principal amount of the notes, plus accrued interest. If the Company undergoes a change of control, the note holders will have the right to require the Company to repurchase all or a portion of the notes at a price equal to 101% of the principal amount of the notes, plus accrued interest.

(e) 5.375% Senior Notes Due 2021

On November 5, 2013, the Company issued $1 billion of 5.375% senior notes due November 21, 2021 at par. The notes are unsecured and effectively subordinated to the Company's Credit Facility to the extent of the value of the collateral securing the Credit Facility. The notes are guaranteed on a full and unconditional and joint and several basis by Antero Midstream, Midstream Operating and certain of our future restricted subsidiaries. Interest on the notes is payable on May 1 and November 1 of each year. The Company may redeem all or part of the 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. At any time prior to November 1, 2016, the Company may also redeem the notes, in whole or in part, at a price equal to 100% of the principal amount of the notes plus a "make-whole" premium. If the Company undergoes a change of control, it may be required to offer to purchase notes from the holders. There are no restrictions on the Company's ability to obtain cash dividends or other distributions of funds from its subsidiaries, except those imposed by applicable law.

(6) Long-Term Debt (Continued)

(f) 9.00% Senior Note

The Company assumed a $25 million unsecured 9% note payable in the business acquisition consummated on December 1, 2010. The note was repaid on December 1, 2013.

(g) Treasury Management Facility

The Company has a stand-alone revolving note with a lender under the Credit Facility which provides for up to $25.0 million of cash management obligations in order to facilitate the Company's daily treasury management. Borrowings under the revolving note are secured by the collateral for the revolving credit facility. Borrowings under the facility bear interest at the lender's prime rate plus 1.0%. The note matures on June 1, 2014. At December 31, 2013, there were no outstanding borrowings under this facility.

(7) Asset Retirement Obligations

The following is a reconciliation of the Company's asset retirement obligations for the years ended December 31, 2012 and 2013 (in thousands).

	2012	2013
Asset retirement obligations—beginning of year	$ 6,715	$10,552
Obligations incurred for wells drilled or on properties acquired	9,440	242
Obligations related to assets sold	(6,107)	—
Accretion expense	504	1,065
Asset retirement obligations—end of year	$10,552	$11,859

(8) Profits Interests Awards

Employee Holdings, a limited liability company owned by officers and employees, has issued profits interests to employees. The profits interests participate only in distributions from Antero Investment in liquidity events, meeting requisite financial thresholds after the Class I and other classes of unitholders have recovered their investment and special allocation amounts. The profits interests have no voting rights. As described in note 1, the limited liability company agreement of Antero Investment executed at the closing of the IPO provides a mechanism by which the shares of the Company's common stock to be allocated among the members of Antero Investment, including Employee Holdings, will be determined. As a result, the satisfaction of all performance and service conditions relative to the profits interests awards held by Employee Holdings in Antero Investment became probable. Accordingly, we recognized approximately $365 million of stock compensation expense for the vested profits interests through December 31, 2013 and will recognize an additional approximate $121 million over the remaining service period. All available profits interest awards were made prior to the date of the IPO and no additional awards will be made.

(9) Stock-Based Compensation

The Company is authorized to grant up to 16,906,500 stock-based compensation awards to employees and directors of the Company under the Antero Resources Corporation Long-Term Incentive Plan (the Plan). The Plan allows stock-based compensation awards to be granted in a variety of forms, including stock options, stock appreciation rights, restricted stock awards, restricted stock unit awards, dividend equivalent awards, and other types of awards. The terms and conditions of the awards granted are established by the Compensation Committee of the Company's Board of Directors. A total of 16,791,068 shares are available for future grant under the Plan as of December 31, 2013.

Our stock-based compensation expense is as follows for the year ended December 31, 2013 (in thousands):

Profits interests awards (see note 8)	$364,957
Restricted stock	219
Stock options	104
Total expense	$365,280

Restricted Stock Awards

Restricted stock awards vest subject to the satisfaction of service requirements. The grant date fair value of these awards are determined based on the price of the Company's common stock on the date of the grant. A summary of restricted stock awards activity during the year ended December 31, 2013 is as follows:

	Number of shares	Weighted average grant date fair value	Aggregate intrinsic value (in thousands)
Total granted and unvested, January 1, 2013	—	—	—
Granted	45,093	$54.27	
Vested	—		
Forfeited	—		
Total awarded and unvested—December 31, 2013	45,093	$54.27	$2,861

The outstanding unvested restricted stock awards at December 31, 2013 are scheduled to vest as follows:

Vesting date	Number of awards
2014	20,818
2015	8,092
2016	8,092
2017	8,091

(9) Stock-Based Compensation (Continued)

Stock Options

Stock options granted under the Plan to date vest over periods from one to four years and have a maximum contractual life of 10 years. We recognize expense related to stock options on a straight-line basis over the requisite service period, less awards expected to be forfeited. Stock options are granted with an exercise price equal to the market price of our common stock on the date of grant. A summary of stock option activity for the year ended December 31, 2013 is as follows:

	Stock options	Weighted average exercise price	Weighted average remaining contractual life	Intrinsic value (in thousands)
Outstanding at January 1, 2013	—	—	—	—
Options granted	70,339	$54.15		
Options exercised	—	—		
Options cancelled	—	—		
Options expired	—	—		
Outstanding at December 31, 2013	70,339	$54.15		
Vested or expected to vest as of December 31, 2013	70,339	$54.15	9.79	$653
Exercisable at December 31, 2013	—		9.79	$653

We use a Black-Scholes option-pricing model to determine the fair value of our stock options. Expected volatility was derived from the volatility of the historical stock prices of a peer group of similar publicly traded companies' stock prices. The risk-free interest rate was determined using the implied yield currently available for zero-coupon U.S. government issues with a remaining term approximating the expected life of the options. We assumed no dividend yield.

The following table presents information regarding the weighted average fair value for options granted during 2013 and the assumptions used to determine fair value. There were no options exercised during 2013.

Dividend yield	—%
Volatility	35%
Risk-free interest rate	1.48%
Expected life (years)	6.17
Weighted average fair value of options granted	$20.20

As of December 31, 2013, there was $1.3 million of unrecognized stock-based compensation expense related to nonvested stock options. That expense is expected to be recognized over a weighted average period of 4 years.

(10) Financial Instruments

The carrying values of trade receivables and trade payables at December 31, 2012 and 2013 approximated market value because of their short-term nature. The carrying value of the bank credit facility at December 31, 2012 and 2013 approximated fair value because the variable interest rates are reflective of current market conditions.

The fair value of the Company's senior notes was approximately $1.9 billion, based on Level 2 market data inputs at December 31, 2013.

See (note 11) for information regarding the fair value of derivative financial instruments.

(11) Derivative Instruments

(a) Commodity Derivatives

The Company periodically enters into natural gas derivative contracts with counterparties to hedge the price risk associated with a portion of its production. These derivatives are not held for trading purposes. To the extent that changes occur in the market prices of natural gas, the Company is exposed to market risk on these open contracts. This market risk exposure is generally offset by the change in market prices of natural gas recognized upon the ultimate sale of the natural gas produced.

For the years ended December 31, 2011, 2012, and 2013, the Company was party to natural gas fixed price swaps. When actual commodity prices exceed the fixed price provided by the swap contracts, the Company pays the excess to the counterparty, and when actual commodity prices are below the contractually provided fixed price the Company receives the difference from the counterparty. The Company's natural gas swaps have not been designated as hedges for accounting purposes; therefore, all gains and losses were recognized in income currently.

(11) Derivative Instruments (Continued)

As of December 31, 2013, the Company has entered into fixed price natural gas and oil swaps in order to hedge a portion of its natural gas and oil production from January 1, 2014 through December 31, 2019 as summarized in the following table.

	Natural gas MMbtu/day	Oil Bbls/day	Weighted average index price
Year ending December 31, 2014:			
CGTAP-TCO	210,000	—	$ 5.11
Dominion South	160,000	—	5.15
NYMEX	230,000	—	3.99
CGLA	10,000	—	3.87
NYMEX-WTI	—	3,000	96.53
2014 Total	610,000	3,000	
Year ending December 31, 2015:			
CGTAP-TCO	130,000		$ 4.93
Dominion South	230,000		5.60
NYMEX	140,000		4.08
CGLA	40,000		4.00
2015 Total	540,000		
Year ending December 31, 2016:			
CGTAP-TCO	80,000		$ 4.67
Dominion South	272,500		5.35
NYMEX	110,000		4.18
CGLA	170,000		4.09
2016 Total	632,500		
Year ending December 31, 2017:			
CGTAP-TCO	20,000		$ 4.02
NYMEX	230,000		4.43
CGLA	420,000		4.27
CCG	70,000		4.57
2017 Total	740,000		
Year ending December 31, 2018:			
NYMEX	620,000		$ 4.66
Year ending December 31, 2019:			
NYMEX	277,500		$ 4.51

(b) Interest Rate Derivatives

In the past, the Company has entered into various floating-to-fixed interest rate swap derivative contracts to manage exposures to changes in interest rates from variable rate obligations. Under the

(11) Derivative Instruments (Continued)

swaps, the Company made payments to the swap counterparty when the variable LIBOR three-month rate fell below the fixed rate or received payments from the swap counterparty when the variable LIBOR three-month rate went above the fixed rate. The Company had no outstanding interest rate swap agreements at December 31, 2012 and 2013.

(c) Summary

The following is a summary of the fair values of derivative instruments not designated as hedges for accounting purposes and where such values are recorded in the consolidated balance sheets as of December 31, 2012 and 2013. None of the Company's derivative instruments are designated as hedges for accounting purposes.

	2012		2013	
	Balance sheet location	Fair value	Balance sheet location	Fair value
		(In thousands)		(In thousands)
Asset derivatives not designated as hedges for accounting purposes:				
Commodity contracts	Current assets	$160,579	Current assets	$183,000
Commodity contracts	Long-term assets	371,436	Long-term assets	677,780
Total asset derivatives		$532,015		$860,780
Liability derivatives not designated as hedges for accounting purposes:				
Commodity contracts	Current liabilities	—		646
Net derivatives		$532,015		$860,134

The following tables present the gross amounts of recognized derivative assets and liabilities, the amounts offset under netting arrangements with counterparties, and the resulting net amounts presented in the condensed consolidated balance sheets for the periods presented, all at fair value (in thousands):

	December 31, 2012			December 31, 2013		
	Gross amounts of recognized assets	Gross amounts offset on balance sheet	Net amounts of assets on balance sheet	Gross amounts of recognized assets	Gross amounts offset on balance sheet	Net amounts of assets (liabilities) on balance sheet
Commodity derivative assets	$597,359	$(65,344)	$532,015	$887,034	$(26,254)	$860,780
Commodity derivative liabilities	—	—	—	—	(646)	(646)

(11) Derivative Instruments (Continued)

The following is a summary of derivative fair value gains (losses) and where such values are recorded in the consolidated statements of operations for the years ended December 31, 2011, 2012, and 2013 (in thousands):

	Statement of operations location	2011	2012	2013
Commodity derivative fair value gains	Revenue	$496,064	$179,546	$491,689
Commodity derivative fair value gains	Discontinued operations	180,130	46,358	—
Total commodity derivative fair value gains		676,194	225,904	491,689
Interest rate derivative fair value losses	Other expenses	(94)	—	—
Net derivative fair value gains		$676,100	$225,904	$491,689

The fair value of commodity and interest rate derivative instruments was determined using Level 2 inputs.

(12) Income Taxes

For the years ended December 31, 2011, 2012, and 2013 income tax expense from continuing operations consisted of the following (in thousands):

	2011	2012	2013
Current income tax expense (benefit)	$ —	$ 15,000	$ (4,000)
Deferred income tax expense	185,297	106,229	190,210
Total income tax expense from continuing operations	$185,297	$121,229	$186,210

The income tax expense from continuing operations differs from the amount that would be computed by applying the U.S. statutory federal income tax rate of 35% to consolidated income for the years ended December 31, 2011, 2012, and 2013, as a result of the following (in thousands):

	2011	2012	2013
Federal income tax expense	$159,770	$121,276	$ 56,708
State income tax expense, net of federal benefit	23,593	4,761	21,429
Nondeductible stock compensation	—	—	127,736
Change in valuation allowance	(934)	(4,872)	(20,919)
Other	2,868	64	1,256
Total income tax expense from continuing operations	$185,297	121,229	186,210

(12) Income Taxes (Continued)

For the years ended December 31, 2011, 2012, and 2013 income tax expense (benefit) was allocated to continuing and discontinued operations as follows (in thousands):

	2011	2012	2013
Continuing operations	$185,297	$ 121,229	$186,210
Discontinued operations and sale of discontinued operations	45,155	(272,553)	3,249
Total income tax expense (benefit)	$230,452	$(151,324)	$189,459

Deferred income taxes reflect the impact of temporary differences between amounts of assets and liabilities for financial reporting purposes and such amounts as measured by tax laws. The tax effect of the temporary differences giving rise to net deferred tax assets and liabilities at December 31, 2012 and 2013 is as follows (in thousands):

	2012	2013
Deferred tax assets:		
Net operating loss carryforwards	$ 417,385	$ 449,961
Capital loss carryforwards	5,367	—
Minimum tax credit carryforward	15,000	11,000
Other	5,006	5,373
Total deferred tax assets	442,758	466,334
Valuation allowance	(47,678)	(26,759)
Net deferred tax assets	395,080	439,575
Deferred tax liabilities:		
Unrealized gains on derivative instruments	206,937	328,534
Oil and gas properties	342,455	458,812
Total deferred tax liabilities	549,392	787,346
Net deferred tax liabilities	$(154,312)	$(347,771)

In assessing the realizability of deferred tax assets, management considers whether some portion or all of the deferred tax assets will be realized based on a more likely than not standard of judgment. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible. Management considers the scheduled reversal of deferred tax liabilities, projected future taxable income, and tax planning strategies in making this assessment. Based upon the projections for future taxable income over the periods in which the deferred tax assets are deductible, management believes that the Company will not realize the benefits of all of these deductible differences and has recorded a valuation allowance of approximately $48 million and $27 million at December 31, 2012 and 2013, respectively, which is primarily related to capital loss carryforwards and certain state NOL carryforwards related to states where we no longer operate. The amount of the deferred tax asset considered realizable could be reduced in the near term if estimates of future taxable income during the carryforward period are revised.

(12) Income Taxes (Continued)

The calculation of the Company's tax liabilities involves uncertainties in the application of complex tax laws and regulations. The Company gives financial statement recognition to those tax positions that it believes 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 noncurrent income taxes payable (included in other long-term liabilities) and an increase in noncurrent deferred tax liabilities. No impact to the Company's 2013 effective tax rate would result. As of December 31, 2013, interest of $0.5 million has been accrued on unrecognized tax benefits. A reconciliation of beginning and ending amount of unrecognized tax benefits is as follows:

	2013
Balance at beginning of year	$15,000
Revised estimate of unrecognized tax position	(4,000)
Balance at end of year	$11,000

The Company's corporate subsidiaries have U.S. Federal and state net operating loss carryforwards (NOLs) as of December 31, 2013 of $1.2 billion and $1.1 billion, respectively, which expire at various dates from 2024 to 2033.

The tax years 2010 through 2013 remain open to examination by the U.S. Internal Revenue Service. The Company and subsidiaries file tax returns with various state taxing authorities; these returns remain open to examination for tax years 2009 through 2013. 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.

(13) Commitments

The following is a schedule of future minimum payments for firm transportation agreements, drilling and compression facility obligations, and leases that have remaining lease terms in excess of one year as of December 31, 2013 (in millions).

	Firm transportation (a)	Gas processing, gathering and compression (b)	Drilling rigs and frac Services (c)	Office and equipment (d)	Total
Year ending December 31:					
2014	$ 120.5	$ 182.8	$150.9	$ 3.9	$ 458.1
2015	159.5	184.7	68.3	4.1	416.6
2016	160.9	196.1	13.7	3.8	374.5
2017	158.4	192.5	—	3.2	354.1
2018	159.0	189.1	—	1.5	349.6
Thereafter	1,002.9	836.1	—	14.1	1,853.1
Total	$1,761.2	$1,781.3	$232.9	$30.6	$3,806.0

(a) Firm Transportation

The Company has entered into firm transportation agreements with various pipelines in order to facilitate the delivery of production to market. These contracts commit the Company to transport minimum daily natural gas volumes or ethane at a negotiated rate, or pay for any deficiencies at a specified reservation fee rate. 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, the Company will record in our financial statements our proportionate share of costs based on our working interest.

(b) Gas Processing and Compression Service Commitments

The Company has entered into various long-term gas processing agreements for certain of its production that will allow us to realize the value of our NGLs. The minimum payment obligations under the agreements are presented in the table.

The Company has various compressor service agreements with third parties that provide for payments based on volumes compressed and have minimum payment obligations which are presented in the table.

The values in the table represent the gross amounts that we are committed to pay; however, the Company will record in our financial statements our proportionate share of costs based on our working interest.

(c) Drilling Rig Service Commitments

The Company has obligations under agreements with service providers to procure drilling rigs and compression and frac services. At December 31, 2013, the Company had contracts for the services of 20 rigs. The contracts expire at various dates from March 2014 through November 2016. The values in the

(13) Commitments (Continued)

table represent the gross amounts that we are committed to pay; however, the Company will record in our financial statements our proportionate share of costs based on our working interest.

(d) Office and Equipment Leases

The Company leases various office space and equipment under operating lease arrangements. Rental expense under operating leases is included in general and administrative expenses and was $1.0 million, $1.1million, and $1.8 million for the years ended December 31, 2011, 2012, and 2013, respectively.

(14) Contingencies

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

(15) Segment Information

See note 1 for a description of the Company's determination of its reportable segments for 2013. Prior to 2013, midstream gathering and 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 2013 (in thousands):

	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
Depiction, depreciation, and amortization	$ 220,857	11,346	2,773	(1,100)	233,876
Interest expense	$ 136,453	155	9	—	136,617
Income tax expense	$ 186,210	—	—	—	186,210
Operating income(1)	$ 335,901	8,938	27,296	(30,928)	341,207
Segment assets	$6,580,282	561,855	230,247	(758,803)	6,613,581
Capital expenditures for segment assets	$2,110,358	389,453	203,790	(32,028)	2,671,573

(1) All general and administrative expenses are included in the exploration and production segment.

(16) Subsidiary Guarantor

Antero Resources Corporation (the parent) and its wholly owned subsidiary each have fully and unconditionally guaranteed the Company's senior notes. The following Condensed Consolidating

(16) Subsidiary Guarantor (Continued)

Balance Sheet at December 31, 2013, as of December 31, 2013, present financial information for Antero Resources Corporation as the Parent on a stand-alone basis (carrying its investment in subsidiary on the equity method), financial information for the subsidiary guarantor (Antero Resources Midstream LLC), and the consolidation and elimination entries necessary to arrive at the information for the Company on a consolidated basis. The guarantor subsidiary had no revenues, expenses, or cash flow during the year ended December 31, 2013. The subsidiary is not restricted from making distributions to the Company.

Condensed Consolidating Balance Sheets

December 31, 2013

(In thousands)

	Parent	Guarantor Subsidiary	Eliminations	Consolidated
Assets				
Current assets:				
Cash and cash equivalents	$ 17,487	$—	$—	$ 17,487
Other	316,077	1	(1)	316,077
Total current assets	333,564	1	(1)	333,564
Property and equipment, net	5,559,656	—	—	5,559,656
Other long-term assets	720,361	—	—	720,361
Investment in subsidiary	1	—	(1)	—
	$6,613,582	$ 1	$(2)	$6,613,581
Liabilities and Stockholders' Equity				
Current liabilities	$ 622,229	$—	$	$ 622,229
Long-term debt	2,078,999	—	—	2,078,999
Other long-term liabilities	313,693	—	—	313,693
Due to subsidiary	1	—	(1)	—
Total liabilities	3,014,922	—	(1)	3,014,921
Stockholders' or member's equity	3,598,660	1	(1)	3,598,660
Total liabilities and equity	$6,613,582	$ 1	$(2)	$6,613,581

(17) Quarterly Financial Information (Unaudited)

The Company's quarterly financial information for the years ended December 31, 2012 and 2013 is as follows (in thousands, except per share amounts):

	First quarter	Second quarter	Third quarter	Fourth quarter
Year ended December 31, 2012:				
Total operating revenues	$553,741	$ 38,925	$ (92,038)	$235,090
Total operating expenses	43,405	62,381	74,840	111,077
Operating income (loss)	510,336	(23,456)	(166,878)	124,013
Income (loss) from continuing operations	287,555	(33,237)	(113,887)	84,845
Income (loss) from discontinued operations	40,176	(444,850)	(13,791)	(91,880)
Net income (loss)	327,731	(478,087)	(127,678)	(7,035)
Earnings (loss) per common share—basic:				
Continuing operations	$ 1.10	$ (0.12)	$ (0.44)	$ 0.32
Discontinued operations	0.15	(1.70)	(0.05)	(0.35)
Net income (loss)	$ 1.25	$ (1.82)	$ (0.49)	$ (0.03)
Earnings (loss) per common share—diluted:				
Continuing operations	$ 1.10	$ (0.12)	$ (0.44)	$ 0.32
Discontinued operations	0.15	(1.70)	(0.05)	(0.35)
Net income (loss)	$ 1.25	$ (1.82)	$ (0.49)	$ (0.03)

	First quarter	Second quarter	Third quarter	Fourth quarter
Year Ended December 31, 2013:				
Total operating revenues	$ 61,454	$387,144	$384,522	$ 480,014
Total operating expenses	109,923	138,758	161,914	561,332
Operating income (loss)	(48,469)	248,386	222,608	(81,318)
Income (loss) from continuing operations	(47,997)	131,193	117,794	(225,177)
Income (loss) from discontinued operations	—	—	3,100	2,157
Net income (loss)	(47,997)	131,193	120,894	(223,020)
Earnings (loss) per common share—basic:				
Continuing operations	$ (0.18)	$ 0.50	$ 0.45	$ (0.86)
Discontinued operations	—	—	0.01	0.01
Net income (loss)	$ (0.18)	$ 0.50	$ 0.46	$ (0.85)
Earnings (loss) per common share—diluted:				
Continuing operations	$ (0.18)	$ 0.50	$ 0.45	$ (0.86)
Discontinued operations	—	—	0.01	0.01
Net income (loss)	$ (0.18)	$ 0.50	$ 0.46	$ (0.85)

(18) Supplemental Information on Oil and Gas Producing Activities (Unaudited)

The following is supplemental information regarding our consolidated oil and gas producing activities. The amounts shown include our net working interests in all of our oil and gas properties.

(a) Capitalized Costs Relating to Oil and Gas Producing Activities

	Year ended December 31	
	2012	2013
	(In thousands)	
Proved properties	$1,682,297	$3,621,672
Unproved properties	1,243,237	1,513,136
	2,925,534	5,134,808
Accumulated depreciation and depletion	(158,210)	(383,921)
Net capitalized costs	$2,767,324	$4,750,887

(b) Costs Incurred in Certain Oil and Gas Activities

	Year ended December 31		
	2011	2012	2013
Acquisition costs:			
Proved property	$105,405	$ 10,254	$ 15,300
Unproved property	195,131	687,403	440,825
Development costs	432,147	678,276	780,583
Exploration costs	95,563	158,074	835,382
Total costs incurred	$828,246	$1,534,007	$2,072,090

(c) Results of Operations (Including Discontinued Operations) for Oil and Gas Producing Activities

	Year ended December 31		
	2011	2012	2013
Revenues	$391,994	$390,378	$ 821,445
Operating expenses:			
Production expenses	136,635	185,505	278,348
Exploration expenses	9,876	15,339	22,272
Depreciation and depletion	164,011	181,664	219,830
Impairment of unproved properties	11,051	13,032	10,928
Results of operations before income tax expense (benefit)	70,421	(5,162)	290,067
Income tax (expense) benefit	(26,056)	2,008	(110,805)
Results of operations	$ 44,365	$ (3,154)	$ 179,262

(18) Supplemental Information on Oil and Gas Producing Activities (Unaudited) (Continued)

(d) Oil and Gas Reserves

The following table sets forth the net quantities of proved reserves and proved developed reserves during the periods indicated. This information includes the oil and gas segment's royalty and net working interest share of the reserves in oil and gas properties. Net proved oil and gas reserves for the year ended December 31, 2011, 2012, and 2013 were prepared by the Company's reserve engineers and audited by DeGolyer and MacNaughton (D&M) or Ryder Scott utilizing data compiled by us. There are many uncertainties inherent in estimating proved reserve quantities, and projecting future production rates and timing of future development costs. In addition, reserve estimates of new discoveries are more imprecise than those of properties with a production history. Accordingly, these estimates are subject to change as additional information becomes available. All reserves are located in the United States.

Proved reserves are the estimated quantities of crude oil, condensate, and natural gas that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known oil and gas reservoirs under existing economic and operating conditions at the end of the respective years. Proved developed reserves are those reserves expected to be recovered through existing wells with existing equipment and operating methods. The Company estimates proved reserves using average prices received for the previous 12 months.

Proved undeveloped reserves include drilling locations that are more than one offset location away from productive wells and are reasonably certain of containing proved reserves and which are scheduled to be drilled within five years under the Company's development plans. The Company's development plans for drilling scheduled over the next five years are subject to many uncertainties and

(18) Supplemental Information on Oil and Gas Producing Activities (Unaudited) (Continued)

variables, including availability of capital; future oil and gas prices; and cash flows from operations, future drilling costs, demand for natural gas, and other economic factors.

	Natural gas (Bcf)	NGLS (MMBbl)	Oil and condensate (MMBbl)	Equivalents (Bcfe)
Proved reserves:				
December 31, 2010	2,543	104	10	3,231
Revisions	(223)	2	7	(172)
Extensions, discoveries and other additions	1,644	57	—[a]	1,982
Production	(84)	(1)	—[a]	(89)
Purchase of reserves	52	2		66
Sales of reserves in place	(1)	—	—	(1)
December 31, 2011	3,931	164	17	5,017
Revisions	198	4	—[a]	222
Extensions, discoveries and other additions	1,242	115	3	1,951
Production	(87)	—[a]	—[a]	(87)
Sale of reserves in place	(1,590)	(80)	(17)	(2,174)
December 31, 2012	3,694	203	3	4,929
Revisions	152	(140)	—[a]	(788)
Extensions, discoveries and other additions	3,084	76	7	3,682
Production	(177)	(2)	—[a]	(191)
December 31, 2013	6,753	137	10	7,632

[a] Less than 1.0.

	Natural gas (Bcf)	NGLS (MMBbl)	Oil and condensate (MMBbl)	Equivalents (Bcfe)
Proved developed reserves:				
December 31, 2011	718	19	2	844
December 31, 2012	828	36	1	1,047
December 31, 2013	1,818	33	2	2,022
Proved undeveloped reserves:				
December 31, 2011	3,213	145	15	4,173
December 31, 2012	2,866	167	2	3,882
December 31, 2013	4,936	105	8	5,610

Significant items included in the categories of proved developed and undeveloped reserve changes for the years 2010, 2011, and 2012 in the above table include the following:

- 2011—Of the 1,982 Bcfe of extensions and discoveries in 2011, 93 Bcfe related to the Arkoma Basin in Oklahoma, 61 Bcfe related to the Piceance Basin in Colorado, 1,816 Bcfe related to the Appalachian Basin in Pennsylvania and West Virginia, and 12 Bcfe related to other areas.

(18) Supplemental Information on Oil and Gas Producing Activities (Unaudited) (Continued)

Revisions include negative revisions of 6 Bcfe due to price, negative revisions of 346 Bcfe due to performance, and positive revisions of 180 Bcfe due to the execution of gas processing agreements in the Appalachian Basin. Extensions and discoveries are primarily the result of increased development activity in the Appalachian Basin.

- 2012—Extensions, discoveries, and other additions during 2012 of 1,951 Bcfe were added through the drilling in the Marcellus and Utica Shales, including the addition of 709 Bcfe attributable to NGLs and oil. Downward price revisions resulted in a reduction of proved reserves of 102 Bcfe. Performance revisions increased proved reserves by 324 Bcfe. Sales of proved reserves of 2,174 Bcfe are the result of the sale of our Arkoma and Piceance Basin properties.
- 2013—Extensions, discoveries, and other additions during 2013 of 3,682 Bcfe were added through exploratory and developmental drilling in the Marcellus and Utica Shales. Downward revisions of 788 Bcfe resulted from changing the underlying production assumption used to estimate reserves to ethane rejection at December 31, 2013 from ethane recovery at December 31, 2012 as well as the reclassification of certain wells to the probable reserves category in 2013 because they are no longer expected to be drilled within five years of initial booking.

The following table sets forth the standardized measure of the discounted future net cash flows attributable to our proved reserves. Future cash inflows were computed by applying historical 12-month unweighted first day of the month average prices. Future prices actually received may materially differ from current prices or the prices used in the standardized measure.

Future production and development costs represent the estimated future expenditures (based on current costs) to be incurred in developing and producing the proved reserves, assuming continuation of existing economic conditions. Future income tax expenses were computed by applying statutory income tax rates to the difference between pretax net cash flows relating to our proved reserves and the tax basis of proved oil and gas properties. In addition, the effects of statutory depletion in excess of tax basis, available net operating loss carryforwards, and alternative minimum tax credits were used in computing future income tax expense. The resulting annual net cash inflows were then discounted using a 10% annual rate.

	Year ended December 31		
	2011	2012	2013
Future cash inflows	$20,046	$12,151	$30,113
Future production costs	(3,491)	(1,660)	(5,967)
Future development costs	(5,085)	(3,270)	(5,349)
Future net cash flows before income tax	11,470	7,221	18,797
Future income tax expense	(3,287)	(1,603)	(5,308)
Future net cash flows	8,183	5,618	13,489
10% annual discount for estimated timing of cash flows	(5,713)	(4,017)	(8,979)
Standardized measure of discounted future net cash flows	$ 2,470	$ 1,601	$ 4,510

(18) Supplemental Information on Oil and Gas Producing Activities (Unaudited) (Continued)

The 12-month weighted average prices used to estimate the Company's total equivalent reserves were as follows:

	Arkoma	Piceance	Appalachia
		(Per Mcfe)	
December 31, 2011	$3.90	$3.84	$4.16
December 31, 2012	NA	NA	2.78
December 31, 2013	NA	NA	3.95

(f) Changes in Standardized Measure of Discounted Future Net Cash Flow

	Year ended December 31		
	2011	2012	2013
Sales of oil and gas, net of productions costs	$ (255)	$ (147)	$ (761)
Net changes in prices and production costs	215	(1,631)	1,061
Development costs incurred during the period	247	296	384
Net changes in future development costs	(106)	(92)	(181)
Extensions, discoveries and other additions	1,684	813	3,441
Acquisitions	51	—	2
Divestitures		(1,277)	—
Revisions of previous quantity estimates	(182)	88	(270)
Accretion of discount	147	322	192
Net change in income taxes	(605)	653	(1,165)
Other changes	177	106	206
Net increase (decrease)	1,373	(869)	2,909
Beginning of year	1,097	2,470	1,601
End of year	$2,470	$ 1,601	$ 4,510

Corporate Information

DIRECTORS

ROBERT J. CLARK
Audit Committee
Compensation Committee

RICHARD W. CONNOR
Chairman of the Audit Committee

BENJAMIN A. HARDESTY
Compensation Committee
Nominating Committee

PETER R. KAGAN
Nominating Committee

W. HOWARD KEENAN, JR.
Nominating Committee

JAMES R. LEVY
Audit Committee
Compensation Committee

CHRISTOPHER R. MANNING
Compensation Committee

MANAGEMENT

PAUL M. RADY
Chairman and
Chief Executive Officer

GLEN C. WARREN, JR.
President and
Chief Financial Officer

ALVYN A. SCHOPP
Chief Administrative Officer,
Regional Vice President
and Treasurer

MICHAEL N. KENNEDY
Vice President – Finance

KEVIN J. KILSTROM
Vice President – Production

BRIAN A. KUHN
Vice President – Land

MARK D. MAUZ
Vice President – Gathering,
Marketing and Transportation

WARD D. MCNEILLY
Vice President – Reserves,
Planning and Midstream

STEVEN M. WOODWARD
Vice President – Business
Development

JONATHAN L. GRANNIS
Co-Head of Geology

ROBERT S. TUCKER
Co-Head of Geology

K. PHIL YOO
Chief Accounting Officer
and Corporate Controller

INVESTOR RELATIONS

Antero Resources Corporation
1615 Wynkoop Street
Denver, Colorado 80202
(303) 357-7310 extension 6782
www.anteroresources.com

TRANSFER AGENT AND REGISTRAR

American Stock Transfer and
Trust Company, LLC
6201 15th Avenue
Brooklyn, NY 11219
(800) 937-5449

INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

KPMG LLP
Denver, Colorado

LEGAL COUNSEL

Vinson & Elkins LLP
New York, New York and
Houston, Texas

UNITHOLDER INFORMATION

Our common units are publicly traded on the NYSE under the symbol "AR"

CORPORATE HEADQUARTERS

Antero Resources Corporation
1615 Wynkoop Street
Denver, Colorado 80202

FORWARD-LOOKING STATEMENT

The Annual Report 2013 includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Such forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond Antero's control. All statements, other than historical facts included in this release, are forward-looking statements. All forward-looking statements speak only as of the date of this annual report. Although Antero believes that the plans, intentions and expectations reflected in or suggested by the forward-looking statements are reasonable, there is no assurance that these plans, intentions or expectations will be achieved. Therefore, actual outcomes and results could materially differ from what is expressed, implied or forecast in such statements.

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, regulatory changes, the uncertainty inherent in estimating natural gas, NGLs and oil reserves and in projecting 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 our Annual Report on Form 10-K for the year ended December 31, 2013.

Antero Resources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