ANTERO RESOURCES Corp
Form 10-K
February 27, 2014

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

ý **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

o **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. o Yes ý 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. o Yes ý 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. ý Yes o 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). ý Yes o 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. ý

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

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

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

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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.

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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.

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"*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.

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"*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.

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PART I

Items 1 and 2. Business and Properties

Our Company

Antero Resources Corporation is an independent oil and natural gas company engaged in the exploration, development and acquisition of natural gas, NGLs, and oil properties located in the Appalachian Basin. We focus on unconventional reservoirs, which can generally be characterized as fractured shale formations. As of December 31, 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

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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).

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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.

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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.

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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)**	**2012(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.

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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

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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.

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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

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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.

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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

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

	Marcellus	
County	**Gross Acres**	**Net Acres**
Doddridge, WV	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

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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

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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 midstrea