

January 27, 2016



## Antero Resources Announces 4% Increase in Proved Reserves to 13.2 Tcfe

DENVER, Jan. 27, 2016 /PRNewswire/ -- **Antero Resources** (NYSE: AR) ("Antero" or the "Company") today announced reserves as of December 31, 2015.



### Announcement Highlights:

- Proved reserves increased by 4% to 13.2 Tcfe at year-end 2015
- Proved developed reserves increased by 54% to 5.8 Tcfe at year-end 2015
- Replaced 425% of net production in 2015
- All-in finding and development cost for proved reserve additions from all sources was \$0.80 per Mcfe for 2015
- All-in 3-year finding and development cost for proved reserve additions from all sources through 2015 was \$0.57 per Mcfe
- Proved undeveloped reserves at year-end 2015 have estimated future development cost of \$0.69 per Mcfe
- Pre-tax PV-10 of 3P reserves at year-end 2015 was \$6.8 billion at SEC pricing including hedges
- Pre-tax PV-10 of 3P reserves at year-end 2015 was \$13.7 billion at 12/31/2015 strip pricing including hedges

Antero's proved reserves at December 31, 2015 were 13.2 Tcfe, a 4% increase compared to proved reserves at December 31, 2014. Proved, probable and possible ("3P") reserves at year-end 2015 totaled 37.1 Tcfe, which represents a 9% decrease compared to the previous year. Both proved and 3P reserves as of December 31, 2015 exclude 366 million barrels and 1,237 million barrels of ethane, respectively, that is expected remain in the natural gas stream until such time pricing supports full ethane recovery.

Antero replaced 425% of net production in 2015 after giving effect to performance and price revisions and excluding the reclassification of certain locations to the probable category. Finding and development cost for proved reserve additions was \$0.80 per Mcfe, based on unaudited capital expenditures for 2015. This finding and development cost includes drilling and completion capital as well as costs incurred for well pads, roads, certain wellhead facilities, acquisitions, land additions and give effect to performance and price revisions. Drill

bit only finding and development cost was \$0.71 per Mcfe for 2015. The expected reserve life of the Company's proved reserves, based on 2015 production, is approximately 24 years.

Under the Securities and Exchange Commission ("SEC") reporting rules, proved undeveloped reserves are limited to reserves that are planned to be developed within five years of initial booking. The Company reclassified 2.3 Tcfe of proved undeveloped reserves to the probable category in 2015 to comply with the SEC five-year development rule. Antero's 7.4 Tcfe of proved undeveloped reserves will require an estimated \$5.1 billion of future development capital over the next five years, resulting in an estimated average future development cost for proved undeveloped reserves of \$0.69 per Mcfe. The future development capital includes the assumption of legacy contract expirations over the next year and replacement with current market based contracts.

## **Proved Reserves**

As of December 31, 2015, the Company's 13.2 Tcfe of proved reserves were comprised of 72% natural gas, 27% NGLs and 1% oil. The Marcellus Shale accounted for 86% of proved reserves and the Utica Shale accounted for 14%. For 2015, due to the success of Antero's drilling program targeting liquids-rich locations in the Marcellus and Utica Shale plays, the Company added 2.9 Tcfe of proved reserves through the drill bit. At year-end 2015, proved reserves included 1.1 Tcfe of ethane reserves in the Marcellus Shale as the first de-ethanizer was placed on line at the MarkWest Sherwood facility in December 2015 and Antero's first international ethane sales contract is expected to commence in 2017 upon the completion of Mariner East 2. The remaining Marcellus ethane reserves, as well as the Utica ethane reserves, continue to be carried as natural gas reserves as it is assumed that these ethane reserves will be sold on an energy equivalent basis in the natural gas stream. These additions were partially offset by the reclassification of 2.3 Tcfe of proved reserves to the probable category in order to comply with the SEC five-year development rule and 560 Bcfe of negative revisions primarily related to the effect of lower natural gas and oil prices. The majority of the locations associated with the 2.3 Tcfe of reserves reclassified to the probable category are located on the eastern portion of Antero's Marcellus acreage that is currently dedicated to a third-party midstream provider. These primarily dry gas locations have a higher operating cost structure and do not receive liquids-related pricing. As a result, these locations are no longer expected to be drilled within the next five years under the Company's development plans, assuming SEC pricing.

Approximately 30% of Antero's combined 569,000 net acre leasehold position was classified as proved at December 31, 2015. Based on Antero's successful drilling results to date, as well as those of other operators in the vicinity of Antero's leasehold, the Company believes that a substantial portion of its Marcellus and Utica Shale acreage will be added to proved reserves over time as more wells are drilled. No West Virginia or Pennsylvania Utica dry gas locations were classified as 3P reserves at year-end 2015, with the exception of one proved developed producing location, due to the early stage of drilling and production in the play.

Proved developed reserves increased by 54% from year-end 2014 to 5.8 Tcfe at December 31, 2015. The Company added 69 Marcellus and 62 Utica wells to proved developed reserves in 2015. The percentage of proved reserves classified as proved developed increased to 44% at December 31, 2015 as compared to 30% at year-end 2014. Proved

undeveloped reserves decreased by 17% primarily as a result of the reclassification of locations to the probable category due to the application of the SEC five-year development rule in a lower commodity price and reduced activity environment.

Antero's estimate of capital costs incurred during 2015, including drilling and completion costs of \$1.65 billion and leasehold costs of \$199 million, was approximately \$1.85 billion. The leasehold costs included \$39 million for acquisitions and \$160 million for land. Assuming the approximate \$1.85 billion estimate of capital costs, preliminary 2015 all-in finding and development cost for proved reserve additions from all sources, including performance and price revisions, was \$0.80 per Mcfe. Antero's three-year all-in finding and development cost for proved reserve additions from all sources, including price and performance revisions, through 2015 was \$0.57 per Mcfe. The 2015 capital costs are unaudited and preliminary. Final capital costs will be provided in Antero's Annual Report on Form 10-K for the year ended December 31, 2015.

**Summary of Changes in Proved Reserves (in Bcfe)**

|                                                                 |               |
|-----------------------------------------------------------------|---------------|
| <b>Balance at December 31, 2014</b>                             | <b>12,683</b> |
| Extensions, discoveries and additions                           | 2,878         |
| Purchases of proved reserves                                    | —             |
| Performance and price revisions                                 | (560)         |
| Partial ethane recovery                                         | 1,091         |
| Reclassification to probable due to SEC 5-year development rule | (2,332)       |
| Sales of proved reserves                                        | —             |
| Production                                                      | (545)         |
| <b>Balance at December 31, 2015</b>                             | <b>13,215</b> |

| Assumed Appalachian Index Weighted Average Pricing: | 2015 Year-End |                              | Variance     | % Variance |
|-----------------------------------------------------|---------------|------------------------------|--------------|------------|
|                                                     | SEC Pricing   | Strip Pricing <sup>(1)</sup> |              |            |
| WTI Oil Price (\$/Bbl)                              | \$50.13       | \$53.66                      | \$3.53       | 7%         |
| Natural Gas Price (\$/MMbtu)                        | \$2.56        | \$3.23                       | \$0.67       | 26%        |
| C3+ Natural Gas Liquids (\$/Bbl) <sup>(2)</sup>     | \$23.09       | \$26.12                      | \$3.03       | 13%        |
| <b>PV-10 Values (\$ Billion):</b>                   |               |                              |              |            |
| Proved Reserves PV-10                               | \$3.6         | \$5.7                        | \$2.1        | 58%        |
| Hedge PV-10 <sup>(3)</sup>                          | 3.1           | 2.5                          | (0.6)        | (19)%      |
| Total PV-10                                         | <u>\$6.7</u>  | <u>\$8.2</u>                 | <u>\$1.5</u> | <u>22%</u> |

- 1) Strip pricing as of December 31, 2015 for each of the first ten years and flat thereafter. NGL pricing assumes 39%, 46% and 48% of WTI strip prices for 2016, 2017 and 2018 and thereafter, respectively.
- 2) Represents realized NGL price including regional market differentials. NGL price, including regional differential and transportation & fractionation charges, for SEC and Strip pricing was \$18.43 per barrel and \$21.46 per barrel, respectively.
- 3) Hedge PV-10 at strip pricing differs from year-end 2015 mark-to-market value of \$3.1 billion due to the application of a higher discount rate.

SEC prices for reserves, calculated as of December 31, 2015 on a weighted average Appalachian index basis related to company-specific sales points, were \$40.06 per barrel for

oil and \$2.56 per MMBtu for natural gas. Assuming SEC prices, which are not indicative of current forward prices, the pre-tax present value discounted at 10% ("pre-tax PV-10") of the December 31, 2015 proved reserves was \$3.6 billion, a 68% decrease from year-end 2014. Including Antero's hedges as of December 31, 2015 assuming SEC prices, the pre-tax PV-10 value of proved reserves was \$6.7 billion, a 42% decrease from year-end 2014.

Assuming future strip benchmark pricing and applying company-specific production weighting for Appalachian index pricing as of December 31, 2015, the pre-tax PV-10 value of the same year-end 2015 proved reserves was \$5.7 billion which represents a 56% increase over the corresponding SEC reserve based pre-tax PV-10, before hedges. Including Antero's hedges, the pre-tax PV-10 value of proved reserves was \$8.2 billion assuming strip pricing.

### Proved, Probable and Possible Reserves

Antero estimates that it had year-end 2015 3P reserves of 37.1 Tcfe, a 9% decrease from year-end 2014. The 9% decrease in 3P reserves was primarily driven by the removal of 4.6 Tcfe of probable and possible reserves in the Upper Devonian Shale due to lower commodity prices. The 3P reserves contain 29.7 Tcf of natural gas, 1,145 million barrels of NGLs, and 92 million barrels of oil. The Marcellus and Utica Shale comprised 29.6 Tcfe and 7.5 Tcfe of the 3P reserves, respectively. During 2015, Antero added 27,000 net acres in the Marcellus Shale in northern West Virginia while its Utica Shale position in southern Ohio was reduced by 1,000 net acres.

Importantly, 28.4 Tcfe of Antero's 29.6 Tcfe of 3P reserves in the Marcellus, or 96%, were classified as proved and probable reserves ("2P"), reflecting the low risk and statistically repeatable nature of Antero's Marcellus drilling. Further, 84%, or 6.3 Tcfe of Antero's 7.5 Tcfe of 3P reserves in the Utica, were classified as 2P.

The table below summarizes Antero's estimated 3P reserve volumes as of December 31, 2015 using SEC pricing, categorized by operating area:

|                          | Marcellus Shale   |                    |                 |                 |  | Ohio Utica Shale |                    |                 |                 |
|--------------------------|-------------------|--------------------|-----------------|-----------------|--|------------------|--------------------|-----------------|-----------------|
|                          | Gas<br>(Bcf)      | Liquids<br>(MMBbl) | Total<br>(Bcfe) | Gross Locations |  | Gas<br>(Bcf)     | Liquids<br>(MMBbl) | Total<br>(Bcfe) | Gross Locations |
| Proved                   | 8,073             | 555                | 11,406          | 992             |  | 1,459            | 58                 | 1,809           | 214             |
| Probable                 | 14,216            | 458                | 16,961          | 2,185           |  | 3,972            | 83                 | 4,468           | 564             |
| Possible                 | 1,025             | 43                 | 1,282           | 176             |  | 951              | 40                 | 1,191           | 162             |
| <b>Total 3P</b>          | <b>23,314</b>     | <b>1,056</b>       | <b>29,649</b>   | <b>3,353</b>    |  | <b>6,381</b>     | <b>181</b>         | <b>7,468</b>    | <b>940</b>      |
| % Liquids <sup>(1)</sup> |                   |                    | 21%             |                 |  |                  |                    | 15%             |                 |
|                          | Combined Reserves |                    |                 |                 |  |                  |                    |                 |                 |
|                          | Gas<br>(Bcf)      | Liquids<br>(MMBbl) | Total<br>(Bcfe) | Gross Locations |  |                  |                    |                 |                 |
| Proved                   | 9,532             | 614                | 13,215          | 1,206           |  |                  |                    |                 |                 |
| Probable                 | 18,188            | 540                | 21,430          | 2,749           |  |                  |                    |                 |                 |
| Possible                 | 1,976             | 83                 | 2,472           | 338             |  |                  |                    |                 |                 |
| <b>Total 3P</b>          | <b>29,696</b>     | <b>1,237</b>       | <b>37,117</b>   | <b>4,293</b>    |  |                  |                    |                 |                 |
| % Liquids <sup>(1)</sup> |                   |                    | 20%             |                 |  |                  |                    |                 |                 |

(1) Represents liquids volumes as a percentage of total volumes. Combined liquids comprised of 1,145 million barrels of NGLs and 92 million barrels of oil.

Assuming SEC prices, the pre-tax PV-10 of the December 31, 2015 3P reserves was \$3.7 billion before hedges and \$6.8 billion including hedges. Assuming year-end strip pricing, with adjustments similar to SEC pricing, the pre-tax PV-10 of the same year-end 2015 3P reserves was \$11.2 billion which represents a 198% increase over the corresponding SEC reserve based pre-tax PV-10, before hedges. Including Antero's hedges, the pre-tax PV-10 of 3P reserves was \$13.7 billion assuming strip pricing which represents a 101% increase over the corresponding SEC reserve based pre-tax PV-10.

Antero's proved and 3P reserves at December 31, 2015 were prepared by its internal reserve engineers and audited by DeGolyer and MacNaughton ("D&M"). D&M's reserve audit covered properties representing 100% of Antero's total 3P reserves at December 31, 2015.

## **Non-GAAP Disclosure**

Year-end pre-tax PV-10 value is a non-GAAP financial measure as defined by the SEC. We believe that the presentation of pre-tax PV-10 value is relevant and useful to our investors because it presents the discounted future net cash flows attributable to our reserves prior to taking into account corporate future income taxes and our current tax structure. We further believe investors and creditors use pre-tax PV-10 value as a basis for comparison of the relative size and value of our reserves as compared with other companies. We believe that PV-10 estimates using strip pricing can be used within the industry and by creditors and securities analysts to evaluate estimated net cash flows in the current commodity price environment. PV-10 estimates using strip pricing are not adjusted for the likelihood that the pricing scenario will occur, and thus they may not be comparable to PV-10 value using SEC pricing.

The GAAP financial measure most directly comparable to pre-tax PV-10 is the standardized measure of discounted future net cash flows ("Standardized Measure"). We are not yet able to provide a reconciliation of pre-tax PV-10 to Standardized Measure because the discounted future income taxes associated with our reserves is not yet calculable. We expect to include a full reconciliation of pre-tax PV-10 to Standardized Measure in our Annual Report on Form 10-K for the year ended December 31, 2015.

*Antero Resources is an independent natural gas and oil company engaged in the acquisition, development and production of unconventional liquids-rich natural gas properties located in the Appalachian Basin in West Virginia, Ohio and Pennsylvania. The Company's website is located at [www.anteroresources.com](http://www.anteroresources.com).*

## **Cautionary Statements**

*This release includes "forward-looking statements". 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 release. 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.*

*Antero cautions 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 the Company's 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 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 Antero's Annual Report on Form 10-K for the year ended December 31, 2014.*

*The SEC permits oil and gas companies to disclose probable and possible reserves in their filings with the SEC. Antero does not plan to include probable and possible reserve estimates in its filings with the SEC. Antero has provided internally generated estimates that have been audited by its third party reserve engineer in this release. Antero's estimate of proved, probable and possible reserves is provided in this release because management believes it is useful information that is widely used by the investment community in the valuation, comparison and analysis of companies. However, the Company notes that the SEC prohibits companies from aggregating proved, probable and possible reserves in filings with the SEC due to the different levels of certainty associated with each reserve category.*

*This release provides a summary of Antero's reserves as of December 31, 2015, assuming partial ethane "rejection" where sales demand for ethane is not available. Ethane rejection occurs when ethane is left in the wellhead natural gas stream when the natural 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 natural gas at the outlet of the processing plant is higher. Producers will generally elect to "reject" ethane at the processing plant when the price received for the ethane in the natural gas stream is greater than the price received for the ethane being sold as a liquid after fractionation, net of fractionation costs. When ethane is recovered in the processing plant, the Btu content of the residue natural gas is lower, but a producer is then able to recover the value of the ethane sold as a separate natural gas liquid product. In addition, natural gas processing plants can produce the other NGL products (propane, normal butane, isobutene and natural gasoline) while rejecting ethane.*

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