August 2, 2017

Antero Resources Announces 14% Increase in Estimated Mid-Year 3P Reserves

DENVER, Aug. 2, 2017 /PRNewswire/ -- **Antero Resources** (NYSE: AR) ("Antero" or the "Company") today announced estimated reserves as of June 30, 2017.

Highlights:

- **Increased Marcellus wellhead type curves for 199 proved undeveloped and 398 probable locations from 1.7 Bcf/1,000' to approximately 2.0 Bcf/1,000' of lateral**
- **Mid-year 2017 proved reserves increased by 7% to 16.5 Tcfe (41% liquids) from year-end 2016**
- **Pre-tax PV-10 of proved reserves at mid-year 2017 was $10.1 billion at 6/30/2017 strip pricing, including hedges**
- **$0.48 per Mcfe all-in finding and development cost for proved reserve additions for the first half of 2017**
- **3P reserves increased by 14% to 53.0 Tcfe (29% liquids)**
- **Pre-tax PV-10 of 3P reserves at mid-year 2017 was $17.0 billion at 6/30/2017 strip pricing, including hedges**

Antero's estimated proved reserves at June 30, 2017 were 16.5 Tcfe, a 7% increase compared to estimated proved reserves at December 31, 2016. Proved, probable and possible ("3P") reserves at mid-year 2017 totaled 53.0 Tcfe, which represents a 14% increase compared to year-end 2016. Proved and probable reserves comprise over 96% of the total 3P reserves.

Drill bit only finding and development cost, including revisions, was $0.47 per Mcfe for the first half of 2017. All-in finding and development cost for estimated proved reserve additions was $0.48 per Mcfe for mid-year 2017.

Paul Rady, Chairman and CEO, commented, "After announcing encouraging initial results for advanced completions in the Marcellus over the past year, our reserve engineers had the production history necessary to upgrade the type curve on almost 600 proved and probable undrilled locations from 1.7 previously to approximately 2.0 Bcf per 1,000' of lateral at mid-year 2017. Once processed, these rich gas locations deliver gas equivalent reserves of approximately 2.6 Bcfe per 1,000' of lateral assuming ethane rejection. As we expand our advanced completion footprint, we anticipate revising the type curve for a significant portion of our approximate 2,400 undeveloped locations that are still booked at 1.7 Bcf per 1,000' of lateral."

Antero's reserves at June 30, 2017 were prepared by the Company's internal reserve engineers and have not been reviewed or audited by its independent reserve engineers.

Estimated Proved Reserves

As of June 30, 2017, the Company's 16.5 Tcfe of estimated proved reserves were comprised of 59% natural gas, 40% NGLs and 1% oil. The Marcellus Shale accounted for 88% of estimated proved reserves and the Ohio Utica Shale accounted for 12%. For the first half of 2017, Antero added 1.3 Tcfe of estimated proved reserves through the drill bit, which is reflective of the continued productivity gains from the use of advanced completion techniques and longer laterals.

Included in the mid-year 2017 reserves are 294 proved undeveloped locations, or 83% of the total proved undeveloped locations in the Marcellus, booked at an approximate 2.0 Bcf/1,000' type curve. This includes an increase of 199 proved undeveloped locations that were previously booked at a 1.7 Bcf/1,000' type curve at year-end 2016 that have now been upgraded to an approximate 2.0 Bcf/1,000' type curve. The remaining 60 Marcellus proved undeveloped locations are booked at a 1.7 Bcf/1,000' type curve and are generally outside of areas where advanced completions have been applied.

Approximately 29% of Antero's combined 636,000 net acre leasehold position was classified as proved at June 30, 2017 which was in line with year-end 2016. Based on Antero's successful drilling results to date, as well as those of other operators in the vicinity of Antero's leasehold position, the Company believes that a substantial portion of its Marcellus and Ohio Utica Shale undeveloped acreage will be classified as proved over time as more wells are drilled. Virtually no West Virginia Upper Devonian or Utica locations were classified as 3P reserves at June 30, 2017, with the exception of four proved developed producing Upper Devonian locations and one proved developed producing Utica location, due to the early stage of drilling and production in the play.

Estimated proved developed reserves increased by 20% from year-end 2016 to 8.3 Tcfe at June 30, 2017. The Company added 76 Marcellus and 25 Ohio Utica wells to estimated proved developed reserves in the first half of 2017. The percentage of estimated proved reserves classified as proved developed increased to 50% at June 30, 2017 from 45% at year-end 2016. The average heating content of the Marcellus and Utica proved undeveloped locations is 1250 BTU and 1235 BTU, respectively, and the average lateral length is approximately 9,100 feet per location.

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 888 Bcfe of proved undeveloped reserves to the probable category in the first half of 2017 to comply with the SEC five-year development rule. The proved undeveloped locations were reclassified primarily as a result of fewer wells being needed to meet production growth targets due to the enhanced productivity from advanced completions. Antero's 8.2 Tcfe of estimated proved undeveloped reserves will require an estimated $3.3 billion of future development capital over the next five years, resulting in an estimated average future development cost for proved undeveloped reserves of $0.40 per Mcfe. The future development capital is based on a combination of current contracted rates and spot market rates based on today's market pricing.

Antero incurred estimated capital costs of approximately $939 million during the first half of 2017, including drilling and completion costs of $629 million, proved property acquisitions of $179 million and leasehold additions of $130 million. Assuming the $939 million of capital costs, mid-year 2017 all-in finding and development cost for proved reserve additions from all sources, including revisions, was $0.48 per Mcfe.

Summary of Changes in Estimated Proved Reserves (in Bcfe)	
Balance at December 31, 2016	**15,386**
Extensions, discoveries and additions	479
Purchases of estimated proved reserves	620
Revisions[1]	857
Partial ethane recovery	453
Reclassification to probable due to SEC 5-year development rule	(888)
Production	(393)
Balance at June 30, 2017	**16,514**

1) Revisions include 742 Bcfe of performance revisions as a result of the Company's advanced completions program and 115 Bcfe of price revisions.

Costs Incurred ($ Millions)	
Proved leasehold acquisitions:	$179
Leasehold additions	130
Drilling and completion	629
Total costs incurred	**$939**

Finding and Development Costs ($/ Mcfe)	
All-in F&D cost for proved reserve additions[1]	$0.48
Drill bit only F&D cost[2]	$0.47

1) Total costs incurred divided by the summation of 479 Bcfe for extensions, discoveries and additions, 620 Bcfe for purchases and 857 Bcfe for revisions.
2) Drilling and completion costs divided by the summation of 479 Bcfe for extensions, discoveries and additions and 857 Bcfe for revisions.

The table below summarizes both SEC and strip pricing as of June 30, 2017 and the associated PV-10 for estimated proved reserves and hedge values:

	2017 Mid-Year			
Benchmark Pricing:	**SEC Pricing**	**Strip Pricing[1]**	**Variance**	**% Variance**
WTI Oil Price ($/Bbl)	$48.85	$52.06	$3.21	7%

Appalachian Oil Price ($/Bbl)(2)	$43.33	$48.05	$4.72	11%
Nymex Natural Gas Price ($/MMBtu)	$3.07	$3.00	$(0.07)	(2)%
Appalachian Natural Gas Price ($/MMBtu)(2)	$2.88	$2.74	$(0.14)	(5)%
C3+ Natural Gas Liquids ($/Bbl)	$26.68	$30.84	$4.14	16%
C2+ Natural Gas Liquids ($/Bbl)(3)	$16.40	$18.77	$2.37	14%
Pre-Tax PV-10 Values ($ Billions):				
Estimated proved reserves PV-10	$8.0	$8.4	$0.4	5%
Hedge PV-10 (4)	1.3	1.7	0.4	31%
Total PV-10	$9.3	$10.1	$0.8	9%

1) Strip pricing as of June 30, 2017 for each of the first ten years and flat thereafter.
2) Represents SEC and strip prices as of June 30, 2017 on a weighted average Appalachian index basis related to company-specific sales points.
3) Represents realized NGL price including regional market differentials.
4) Hedge PV-10 at strip pricing differs from mid-year 2017 mark-to-market value of $2.0 billion due to the application of a higher discount rate.

Assuming SEC prices, the pre-tax present value discounted at 10% ("pre-tax PV-10") of the June 30, 2017 estimated proved reserves was $8.0 billion, a 117% increase from year-end 2016. Including Antero's hedges as of June 30, 2017 and assuming SEC prices, the pre-tax PV-10 value of estimated proved reserves was $9.3 billion, which represents a 39% increase from year-end 2016 pre-tax PV-10 values. The GAAP standardized measure is based on SEC pricing, after tax, and does not include hedge values. For further discussion on pre-tax PV-10 values, please read "Non-GAAP Disclosure."

Assuming future strip benchmark pricing and applying company-specific production weighting for Appalachian index pricing as of June 30, 2017, the pre-tax PV-10 value of the same mid-year 2017 estimated proved reserves was $8.4 billion. This represents a 5% increase over the corresponding SEC reserve based pre-tax PV-10, before hedges. Including Antero's hedges, the pre-tax PV-10 value of estimated proved reserves was $10.1 billion assuming strip pricing, a 3% increase compared to year-end 2016.

Assuming SEC prices, the pre-tax PV-10 of the June 30, 2017 estimated proved developed reserves was $5.4 billion, which represents an 86% increase compared to year-end 2016.

Assuming future strip benchmark pricing and applying company-specific production weighting for Appalachian index pricing as of June 30, 2017, the pre-tax PV-10 value of the estimated proved developed reserves was $5.5 billion, a 2% increase over the corresponding SEC reserve based pre-tax PV-10, before hedges, and an 8% increase compared to year-end 2016.

Proved, Probable and Possible Reserves

Antero estimates that it had mid-year 2017 3P reserves of 53.0 Tcfe, a 14% increase from year-end 2016. The 14% increase in 3P reserves was driven by a combination of increased type curves in certain areas driven by continued productivity gains from advanced completions, first-half 2017 leasehold acquisitions and an increase in ethane recovery. Approximately 69 million and 954 million barrels of ethane are accounted for as natural gas rather than liquids in proved and 3P reserves as of June 30, 2017, respectively, as this ethane is assumed to remain in the natural gas stream until such time as pricing supports full ethane recovery. As of June 30, 2017, the Company's 53.0 Tcfe of 3P reserves were comprised of 71% natural gas, 28% NGLs and 1% oil. The Marcellus and Ohio Utica Shale comprised 45.7 Tcfe and 7.3 Tcfe of the 3P reserves, respectively.

Importantly, 44.0 Tcfe of Antero's 45.7 Tcfe, or 96% of estimated 3P reserves in the Marcellus were classified as proved and probable reserves ("2P"), reflecting the low risk and statistically repeatable nature of Antero's Marcellus drilling. The 44.0 Tcfe of 2P reserves includes 398 probable locations that were increased from the 1.7 Bcf/1,000' type curve to the approximate 2.0 Bcf/1,000' type curve. Further, 6.9 Tcfe of Antero's 7.2 Tcfe, or 96% of estimated 3P reserves in the Ohio Utica were classified as 2P.

The tables below summarize Antero's estimated 3P reserve volumes as of June 30, 2017 using SEC pricing, categorized by operating area as well as PV-10 values of Antero's 3P reserve volumes using both SEC and strip pricing:

	Marcellus Shale				Ohio Utica Shale			
	Gas (Bcf)	Liquids (MMBbl)	Total (Bcfe)	Gross Locations	Gas (Bcf)	Liquids (MMBbl)	Total (Bcfe)	Gross Locations
Proved	8,219	1,065	14,609	972	1,518	65	1,905	264
Probable	21,673	1,289	29,408	2,795	4,387	94	4,950	608
Possible	1,390	56	1,727	222	316	6	353	59
Total 3P	**31,282**	**2,410**	**45,744**	**3,989**	**6,221**	**165**	**7,208**	**931**
% Liquids(1)			32%				14%	

	Combined 3P Reserves			
	Gas (Bcf)	Liquids (MMBbl)	Total (Bcfe)	Gross Locations
Proved(2)	9,737	1,130	16,514	1,236
Probable	26,059	1,383	34,358	3,403
Possible	1,706	62	2,080	281
Total 3P	**37,502**	**2,575**	**52,952**	**4,920**
% Liquids(1)			29%	

1) Represents liquids volumes as a percentage of total volumes. Combined liquids comprised of 1,170 million barrels of ethane, 1,279 million barrels of C3+ NGLs and 126 million barrels of oil
2) 437 of the 1,236 proved locations were undeveloped locations

Pre-Tax 3P PV-10 Values ($ Billion):	**SEC Pricing**	**Strip Pricing(1)**	**Variance**	**% Variance**
3P Reserves PV-10	$13.3	$15.3	$2.0	15%
Hedge PV-10 (2)	1.3	1.7	0.4	31%
Total PV-10	$14.6	$17.0	$2.4	16%

1) Strip pricing as of June 30, 2017 for each of the first ten years and flat thereafter.

2) Hedge PV-10 at strip pricing differs from mid-year 2017 mark-to-market value of $2.0 billion due to the application of a higher discount rate.

Assuming SEC prices, the pre-tax PV-10 of the June 30, 2017 3P reserves was $13.3 billion before hedges and $14.6 billion including hedges. Assuming mid-year 2017 future strip pricing, with adjustments similar to SEC pricing, the pre-tax PV-10 of the same year-end 2016 3P reserves was $15.3 billion which represents a 15% increase over the corresponding SEC reserve based pre-tax PV-10, before hedges. Including Antero's hedges, the pre-tax PV-10 value of estimated 3P reserves was $17.0 billion assuming strip pricing, a 2% increase compared to year-end 2016. For further discussion on pre-tax PV-10 values, please read "Non-GAAP Disclosure."

Non-GAAP Disclosure

Certain selected financial information in this release is unaudited. Additional unaudited financial information will be provided in Antero's Quarterly Report on Form 10-Q for the quarter ended June 30, 2017, which the Company intends to file with the SEC on August 2, 2017. In this release, Antero has provided a number of unaudited metrics, which include all-in finding and development cost per unit and drill bit only finding and development cost per unit. These non-GAAP metrics are commonly used in the exploration and production industry by companies, investors and analysts in order to measure a company's ability of adding and developing reserves at a reasonable cost. The finding and development costs per unit are statistical indicators that have limitations, including their predictive and comparative value. In addition, because the finding and development costs per unit do not consider the cost or timing of future production of new reserves, such measures may not be adequate measures of value creation. These reserve metrics may not be comparable to similarly titled measurements used by other companies.

Calculations for all-in and drill bit only finding and development cost per unit are based on estimated and unaudited costs incurred in the first half of 2017 and can be found in the footnotes to the table on page two of this release. The calculations for both all-in and drill bit only finding and development cost per unit do not include future development costs required for the development of proved undeveloped reserves.

Pre-tax PV-10 values and pre-tax PV-10 values including hedges are non-GAAP financial measures as defined by the SEC. Antero believes that the presentation of these pre-tax PV-10 values are relevant and useful to its investors because it presents the discounted future net cash flows attributable to reserves and hedges prior to taking into account corporate future income taxes and the Company's current tax structure. The Company further believes investors and creditors use pre-tax PV-10 values as a basis for comparison of the relative size and value of its reserves and hedges as compared with other companies. Antero believes that PV-10 estimates using strip pricing and including hedges 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"). With respect to PV-10 calculated as of an interim date, it is not practical to calculate the taxes for the related interim period because GAAP does not provide for disclosure of standardized measure on an interim basis.

Notwithstanding their use for comparative purposes, the Company's non-GAAP financial measures may not be comparable to similarly titled measure employed by other companies.

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.

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, except for statements of historical fact, made in this release regarding activities, events or developments the Company expects, believes or anticipates will or may occur in the future, such as those regarding future development costs, future capital spending plans, expected drilling and development plans, plans with respect to the rejection of ethane and the prices we will receive for future production as well as future production volumes are 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. 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, 2016 and any subsequently filed Quarterly Report on Form 10-Q.

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 not 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 June 30, 2017, 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.