Legal Disclaimer

This presentation includes "forward-looking statements." Such forward-looking statements are subject to a number of risks and uncertainties, many of which are not under AR's control. All statements, except for statements of historical fact, made in this presentation regarding activities, events or developments Antero expects, believes or anticipates will or may occur in the future, such as those regarding expected results, future commodity prices, future production targets, completion of natural gas or natural gas liquids transportation projects, future earnings, Adjusted EBITDAX, Adjusted Net Cash Provided by Operating Activities, leverage targets, future capital spending plans, improved and/or increasing capital efficiency, continued utilization of existing infrastructure, gas marketability, estimated realized natural gas, natural gas liquids and oil prices, acreage quality, access to multiple gas markets, expected drilling and development plans (including the number, type, lateral length and location of wells to be drilled, the number and type of drilling rigs and the number of wells per pad), projected well costs and cost savings initiatives, including with respect to potential incremental flowback and produced water services by AM, which are subject to approval by the Board of AM, and there can be no assurance that such approval will be obtained, future financial position, future technical improvements, future marketing opportunities, expectations regarding the amount and timing of jury awards, the receipt of which are subject to final orders and the resolutions of appeals processes and access to and cost of capital, 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 presentation. Although AR 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. Except as required by law, AR expressly disclaims any obligation to and does not intend to publicly update or revise any forward-looking statements.

AR cautions you that these forward-looking statements are subject to all of the risks and uncertainties incident to the exploration for and development, production, gathering and sale of natural gas, NGLs and oil, most of which are difficult to predict and many of which are beyond the AR’s control. 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 AR’s Annual Report on Form 10-K for the year ended December 31, 2018.

This presentation includes certain financial measures that are not calculated in accordance with U.S. generally accepted accounting principles (“GAAP”). These measures include (i) Adjusted EBITDAX, (ii) Adjusted Net Cash Provided by Operating Activities, (iii) Free Cash Flow; (iv) Net Debt, (v) PUD F&D cost per unit and (vi) leverage. Please see “Antero Definitions” and “Antero Non-GAAP Measures” for the definition of each of these measures as well as certain additional information regarding these measures, including the most comparable financial measures calculated in accordance with GAAP.

Antero Resources Corporation is denoted as “AR” in the presentation and Antero Midstream Corporation is denoted as “AM”, which are their respective New York Stock Exchange ticker symbols.
### Antero Resources Profile

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<tr>
<th>Metric</th>
<th>Value</th>
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<tbody>
<tr>
<td>Market Cap</td>
<td>$1.0 B</td>
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<tr>
<td>Enterprise Value</td>
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<tr>
<td>LTM EBITDAX</td>
<td>$1.6 B</td>
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<tr>
<td>Ownership in AM (31%)</td>
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<tr>
<td>Leverage (2)</td>
<td>2.3x</td>
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<td>Corporate Debt Ratings</td>
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<td>2019 Net Production Guidance (3)</td>
<td>3.2 Bcfe/d</td>
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<tr>
<td>Liquids/Condensate</td>
<td>149 MBbl/d</td>
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<td>Proved Reserves</td>
<td>18.0 Tcfe</td>
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<tr>
<td>Liquids (4)</td>
<td>1.1 BBbls</td>
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<tr>
<td>Core Undrilled Locations</td>
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</table>


(1) Market cap plus net debt. Includes ownership of $1.1 billion of Antero Midstream.

(2) Leverage is net debt divided by LTM Adjusted EBITDAX at 6/30/19. See appendix for details.

(3) Midpoint of guidance.

(4) Proved reserves contain 498 MMBbls of C3+ NGLs, 554 MMBbls of ethane, and 46 MMBbls of condensate/oil. Assumes approximately 415 MMBbls of additional ethane are left in the natural gas stream.
10+ Years of Premium Drilling Inventory
• Does not assume infill drilling

Liquids-rich Inventory
• AR holds 40% of the core undrilled liquids-rich locations in Appalachia

Contiguous Acreage Position Delivers Efficient Development
• Long-laterals average 12,100’ in Marcellus rich-gas drilling inventory
• Efficient gathering, compression and processing utilization
• Efficient water delivery and produced water handling

High Working and Net Revenue Interest
• ~1,100 horizontal producing wells at 100% operated and 99% average working interest
• AR has 84% average NRI in the Marcellus

Stacked Pay Resource in West Virginia
• Both deep Utica and Upper Devonian development potential over the long-term

Abundant Natural Gas and NGL Takeaway
• Underutilized transportation capacity to premium markets

Note: Rigs as of 8/30/2019.
(1) 76 wells in various stages of drilling, waiting on completion and completing are shown as undrilled locations on map.
Modest Growth Strategy is Optimal

Modest Growth Strategy Optimizes Value and Free Cash Flow
• Fills premium unutilized pipeline capacity by 2022, minimizing net marketing expense
• Results in $400 million more free cash flow in 2022 than going to maintenance capital in 2020 and staying there through 2022 (1)
• Results in 1.5x lower leverage in 2022 (1)
• Liquids-rich well economics support modest production growth

Large Natural Gas Hedge Position Supports Strategy
• 90% and ~50% of expected natural gas production for 2020 and 2021 already “sold” at an average price of $2.87/MMBtu and $2.75/MMBtu, respectively (2)

Recently Announced Well Cost Reduction Supports Strategy
• 10% to 14% well cost reduction to $850/ft. or less expected by 2020 through service cost deflation, efficiency improvement and water initiatives
• $1.2 to $1.3 billion D&C capital program in 2020 approximates expected cash flow including one-time water earn-out and gas contract proceeds (3)

Strong Balance Sheet Supports Strategy
• 2.3x leverage at 6/30/2019 (4)
• Ba2 / BB / BB+ corporate debt ratings
• Credit facility affirmed in 2Q at $4.5 billion borrowing base with $2.5 billion of lender commitments and only $175 million drawn at 6/30/2019
• Ancillary assets include 31% of AM equity and $940 million hedge value at 8/30/19

(1) Based on strip pricing as of 7/31/2019. See next slide for further details on maintenance mode vs modest growth scenarios.
(2) Assumes 10% production CAGR from 2019 production guidance midpoint.
(3) Including $125 million water earn out payment from AM and $150 million in expected gas contract litigation proceeds.
(4) Leverage, which is a non-GAAP measure, is defined as net debt divided by LTM Adjusted EBITDA. For more information, please see the appendix.
A modest growth plan through 2022 provides AR with sustainable free cash flow by filling currently unutilized FT thereby eliminating ~$200 MM of annual unutilized pipeline expenses by 2022.

### Maintenance Mode vs Modest Growth

#### 2020

<table>
<thead>
<tr>
<th>Strip Price Assumptions</th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
</tr>
</thead>
<tbody>
<tr>
<td>NYMEX Henry Hub</td>
<td>$2.49</td>
<td>$2.54</td>
<td>$2.59</td>
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<tr>
<td>WTI</td>
<td>$56.70</td>
<td>$53.89</td>
<td>$52.54</td>
</tr>
<tr>
<td>C3+ NGLs(1)</td>
<td>$28.31</td>
<td>$28.70</td>
<td>$28.77</td>
</tr>
</tbody>
</table>

#### 2020 Maintenance Capital “Off-ramp”

- YE 2019E Production: 3.2 Bcfe/d
- Maintenance Capex (3): ~$700 MM
- Free Cash Flow (4): $150 MM
- Net Marketing Expense: ($260) – ($280) MM
- YE 2020E Leverage: Low 3x

#### 2022 Maintenance Mode vs Modest Growth

- YE 2021E Production (2): ~4.0 Bcfe/d
- Maintenance Capex (3): ~$900 MM
- Free Cash Flow (4): $400 MM
- Net Marketing Expense: ($70) – ($90) MM
- YE 2022E Leverage: Mid 2x

### Note:

1. C3+ NGL pricing represents Mont Belvieu strip pricing based on Antero C3+ NGL component barrel consisting of 56% C3 (propane), 10% isobutane (iC4), 17% normal butane (nC4) and 17% natural gasoline (C5+).
2. Assumes ~10% production CAGR on 2019 production guidance midpoint.
3. Maintenance capex for each respective year represents the average annual drilling and completion capital required to hold production flat from the previous year’s 4Q exit rate.
4. Free cash flow represents adjusted net cash from operating activities less D&C and land capital expenditures. See appendix for further details.

### 2022 Maintenance Mode (2022 Result)

- YE 2021E Production: 3.2 Bcfe/d
- Maintenance Capex (3): ~$700 MM
- Free Cash Flow (4): Neutral
- Net Marketing Expense: ($240) – ($260) MM
- YE 2022E Leverage: 4x

### Stripped Price Assumptions

<table>
<thead>
<tr>
<th></th>
<th>2020</th>
<th>2021</th>
<th>2022</th>
</tr>
</thead>
<tbody>
<tr>
<td>NYMEX</td>
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<td>$28.31</td>
<td>$28.70</td>
<td>$28.77</td>
</tr>
</tbody>
</table>
Firm Transportation Portfolio is a Strategic Asset

AR’s FT portfolio has delivered Appalachia-leading realized natural gas pricing quarter after quarter

Antero Resources Firm Transportation Portfolio vs. Gross Gas Production (MMcf/d)

Premium gas pricing plus realized hedge profits are expected to more than offset the cost of carrying excess transportation capacity until production fills.

Appalachia (M2/Dom S.): 625 MMBtu/d

Assumes 10% CAGR

With 2.1 Bcf/d of capacity to the Gulf Coast, AR has significant exposure to the growing LNG market and increased NYMEX-based pricing.

Total 4.7 Bcf/d

Regional markets and lowest transport cost

Other Premium Markets

Gulf Coast

Potential Maintenance Mode 2022+
Industry Leading Natural Gas Hedge Position

- Defensive strategy to protect cash flow and balance sheet
- $4.5 billion of net realized hedge gains since 2008 (1)

Antero Natural Gas Hedge Profile

Note: Percentage hedged represents percent of expected natural gas production hedged based on a 10% CAGR from the midpoint of 2019 natural gas production guidance.
1) Realized through 6/30/19.
2) Based on current hedge position and strip pricing as of 8/30/19.

~$920 MM Forecasted Hedge Value (2)
With the first full quarter of the ME2 pipeline in service in 2Q, Antero realized a $0.19 per gallon premium to Mont Belvieu on 55% of its C3+ NGLs.

Diversified exposure to both international and domestic markets results in blended C3+ NGL pricing at a premium to Mont Belvieu.

Note: 2020 blend of 70% international / 30% domestic assumes ME2 is fully in service with 275,000 Bbl/d of capacity.

1) Based on Antero C3+ NGL component barrel consists of 56% C3 (propane), 10% isobutane (iC4), 17% normal butane (nC4) and 17% natural gasoline (C5+).
Mariner East 2 has improved AR’s 1H 2019 C3+ NGL price differential to Mont Belvieu by $6.33/Bbl vs 1H18, flipping to a slight premium to Mont Belvieu

Antero Blended C3+ NGL Differential vs. Mont Belvieu

AR’s blended C3+ NGL price realization vs Mont Belvieu has improved by $6.33/Bbl from 1H18

Additionally, since the start up of Mariner East 2, AR’s domestic C3+ NGL realizations vs Mont Belvieu have improved by nearly 30%

Note: AR differential to Mont Belvieu is Based on Antero C3+ NGL component barrel consists of 56% C3 (propane), 10% isobutane (Ic4), 17% normal butane (Nc4) and 17% natural gasoline (C5+).
Marcellus Drilling and Completion Efficiencies Continue

Marcellus Drilling Days - Spud to Spud

Marcellus Avg. Lateral Feet Drilled per Day

Marcellus Avg. Lateral Length Drilled per Well

Marcellus Completion Stages per Day

Note: Percentage increase and decrease arrows represent change in Marcellus data from 2014 to 2Q 2019.
Targeted Marcellus Well Cost Reductions

All of the coming well cost reductions have been tested on a pilot basis and are within Antero’s control.

Targeted Marcellus Well Cost Reductions (January 2019 AFE to 2020 Target)

($MM)

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<td>$11.6</td>
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<td>0.70</td>
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<td>$8.00</td>
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$1.2 - $1.7 MM per Well Targeted Reduction (10% - 14% Reduction)

Assumes 12,000 foot lateral

Majority of water savings expected to begin on January 1, 2020

Already achieved cost reductions include service cost deflation, sand sourcing logistics, well optimization and completion efficiencies.

Targeted cost reductions include further efficiencies and sand savings, drier completions and trucking cost savings from the implementation of expanded produced water services via AM.

All of the coming well cost reductions have been tested on a pilot basis and are within Antero’s control.
AR has achieved approximately $500,000 per well in cost reductions since the January 2019 budget, the remaining ~$950,000 per well expected to begin in 2020.

Well Cost Reduction Components

Targeted Marcellus Well Cost Reductions Percentage Breakdown (1)

- Service Cost Deflation + Efficiency Gains: $650,000 (45%)
- Water Savings: $800,000 (55%)

Majority of water savings initiatives to begin on January 1, 2020.

Assumes 12,000’ lateral length

Well Cost Reduction Calculation (Midpoint of Target Range)

$1.45 MM = $120 / ft Reduction

$970 – $120 = $850 / ft

$1.45 MM per well Cost Reduction Target (1)

1) Total per well cost reduction of $1.45 MM and percentages breakout are based on the midpoint of total targeted well cost savings.
Southwest Marcellus Peer Well Costs ($/Foot of Lateral)

AR targeting $850/ft or lower

Note: Based on company public data via press releases and investor presentations unless denoted as otherwise.

1) AR 2020 target based on midpoint of $830/ft. to $870/ft. well cost range. See previous slide for details.

2) Represents IHS data. Peers include CNX, EQT, RRC and SWN.
AR is targeting ~$60 MM or at least 30% reduction in LOE unit costs through its water savings initiatives for 2020, driven by local treatment of flowback water.
Antero has the liquidity, scale, premium inventory, capital efficiency and hedge support to continue to develop in today’s commodity price environment

Strong Financial Position

- Low 2x leverage with $730 MM absolute debt reduction since 2014 (1)
- AM share ownership of $1.1 B provides ~$200 MM of annual cash flow via dividends
- World class hedge book with ~$940 MM of forecasted hedge value (1)
- $4.5 B borrowing base reaffirmed in 2Q19
- Only $175 MM drawn on revolver with $2.5 B in lender commitments
- Strong corporate debt ratings of Ba2/BB/BB+

Scale and Capital Efficiency

- Large, growing production base with capital spending approximately within cash flow
- Low annual maintenance capital on sizable production base
- Peer-leading liquids-rich inventory provides running room and diversified commodity mix through price cycles

Note: Revolver borrowings as of 6/30/2019. AR market cap and AM share value as of 8/30/2019.
1) Leverage and liquidity as of 6/30/2019. Hedge value assumes strip pricing as of 8/30/2019. See appendix for Non-GAAP items and reconciliation. Leverage is calculated as net debt / LTM adjusted EBITDAX.
Antero’s Senior Notes have traded favorably relative to many of its Appalachian peers

Yield to Worst

Montage Resources 8.875% due 2023
Gulfport Energy 6.375% due 2026
Ascent Resources 7.000% due 2026
CNX Resources 7.250% due 2027
Southwestern Energy 7.750% due 2027
Range Resources 4.875% due 2025
Antero Resources 5.000% due 2025
EQT 3.900% due 2027

High Yield Market is Rarely Closed to E&P Issuers

- The high yield market has not had any E&P issuances for four months or more on only three occasions in the past 12 years
- BB credits like Antero have the most access

Historical High Yield E&P Issuances

- Average monthly WTI ($/bbl)
- Total monthly High Yield E&P issuance proceeds ($MM)
- Average Antero YTW (%) (2)

Total HY E&P transaction proceeds since 2008: $244bn (497 transactions) (1)

Denotes periods with >4 months without E&P HY issuances


1) Represents count of tranches issued.
2) Based on highest YTW across outstanding tranches.
Material demand growth through 2023 plus base decline requires 80 Tcf of new supply

Source: S&P Global Platts. Platts supply forecast through 2023 is within a 2% tolerance of EIA’s supply forecast over the same period. See Antero’s September 2019 “Natural Gas Fundamentals” presentation at www.anteroresources.com/investors for more detail.

1) Historical and forecasted volumes from Platts Analytics. Current volumes as of August 2019.

2) Top five basins/plays that are included in the Rest of U.S. are GOM, SCOOP/STACK, Green River, Barnett, and Anadarko.

3) Base decline calculated using 4Q over 4Q forecast production rates for all wells producing as of year-end 2018 based on Platts bottoms up well by well analysis.
Natural Gas Prices Must Support Dry Gas Development

- Only 32% of the new gas supply needed in the 2019 through 2023 period is forecast to come from **associated gas plays** where natural gas price is not the driving factor for development.
- Remaining 68% of new gas supply must come from **dry gas plays** where producers generally need high-$2.00 to low-$3.00/MMBtu NYMEX natural gas prices to generate a 25% IRR on a half-cycle basis.

![Rich vs. Dry New Supply](image)

- **80 Tcf New Supply Needed Through 2023** (1)
  - 22% Associated Gas Plays (Permian, DJ, Bakken, Scoop/Stack, Appalachia Rich)
  - 68% Dry Gas Plays (NE Marcellus (Susquehanna), SW Marcellus Dry, Utica Dry, Greater Haynesville, Eagle Ford Dry, Rest of U.S.)
  - 10% Appalachia Rich Gas

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1) S&P Global Platts Analytics forecasted supply growth.
Liquids producers with associated gas have superior well economics in the current commodity price environment

Natural Gas Breakeven Price by Region – 25% ROR Half Cycle Breakeven Prices


1) Breakeven price is defined as half cycle pre-tax ROR of 25%. Assumes average 2020-2023 strip WTI oil price of $54.42/Bbl as of 6/30/2019 and C3+ NGL pricing of $29/Bbl. Assumes 12% lower well costs than 2018 budgeted Marcellus costs and 20% lower LOE per unit costs.
2) AR half cycle well economics assume 12,000’ lateral lengths and 69% of AM gathering and compression fees paid by AR to AM to account for AR’s midstream dividend stream from AM (based on 31% ownership of AM).
3) Based on Platts current lower 48 dry marketed natural gas production of 80 Bcf/d at 8/30/2019.

69% of current natural gas supply
Gas rig count is responding to lower natural gas prices with a 14% reduction in horizontal gas rigs since March.

Completion crew count is down 11% since April.

**Horizontal Gas Rig Counts vs NYMEX Henry Hub**

Source: U.S. rig counts from Baker Hughes as of 8/30/2019.

Note: NYMEX Henry Hub price represents natural gas front month futures settlement history.
LNG Demand Growth for Years

3.9 Bcf/d of LNG capacity growth expected in 2019 with multiple “2nd wave” projects seeking FID

AR is a top U.S. LNG supplier with commitments expected to reach 700 MMcf/d by YE 2019

U.S. LNG Export Capacity (2016-2026)

U.S. LNG Export Capacity 2016-2026: In Service, Under Construction, and Approved/Waiting on FID

- **In Service**: 7.1 Bcf/d
- **Under Construction**: 5.5 Bcf/d
- **FID Approved**: 2.7 Bcf/d
- **Waiting on FID**: 18.6 Bcf/d

Total = 33.9 Bcf/d

Antero Total Supply Commitments
Current Supply: 630 MMcf/d
4Q 2019 Supply: 70 MMcf/d
Total: 700 MMcf/d

- Antero supplies 70 MMcf/d to Freeport LNG
- Antero supplies 330 MMcf/d to Cove Point LNG
- Antero supplies 300 MMcf/d to Sabine Pass LNG

A sustainable development plan is critical in volatile markets:

- **Scale / Liquids Diversification**: 2nd Largest NGL producer and 5th largest gas producer with ~1,600 premium undrilled core locations with breakeven natural gas prices well below current strip pricing (1)

- **Ongoing Capital Efficiency Initiatives**: Targeting 10% - 14% lower well costs and lower D&C capital in 2020 (2) and at least 30% lower per unit LOE over the next 12 months

- **World Class Hedge Book**: 100% of natural gas hedged in 2019 and ~90% and ~50% of projected natural gas production hedged in 2020 and 2021, at attractive prices

- **Industry-Leading FT Portfolio**: Delivers NYMEX-plus natural gas pricing (3) and Mont Belvieu-plus NGL pricing on LPG exported volumes

- **Strong Balance Sheet**: 2.3x leverage, $1.6 B of liquidity and strong credit ratings of Ba2/BB/BB+ (4)

The AR business model delivers multiple ways to “Win”

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(1) Strip pricing as of 7/31/2019.
(2) Refer to slide 12 for details. Assumes similar well completion activity to 2019 guidance of ~120 wells turned in line.
(3) After adjusting for Btu.
(4) See appendix for Non-GAAP items and reconciliation. Leverage is calculated as net debt / LTM adjusted EBITDAX. Leverage as of 6/30/19.
Appendix
Midstream simplification transaction results in ownership of one publicly traded midstream entity and better aligns management ownership between the two entities.

**Simplified Structure**

- **Management**
  - 9%
  - 31%
  - 10%

- **Original Private Equity Investors**
  - 3%
  - 3%
  - 10%
  - 10%

- **Public**
  - 88%
  - 49%

309 MM shares

**NYSE: AR**

508 MM shares

**NYSE: AM**

Note: Ownership levels as of June 12, 2019.
Antero’s Sustainability Focus

Environmental Stewardship

- Active member of industry leading greenhouse gas reduction partnerships that promote a science-based, active approach to reduce emissions and improve environmental performance

GHG Emissions

- Antero is an industry leader in greenhouse gas (GHG) emissions intensity with only 3.1 tons CO2e / MBOE in 2018

  Total GHG Emissions and Intensity (CO2e)

<table>
<thead>
<tr>
<th>Year</th>
<th>Thousand Metric Tons</th>
<th>Tons / MBOE</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017</td>
<td>506</td>
<td></td>
</tr>
<tr>
<td>2018</td>
<td>479</td>
<td>3.1</td>
</tr>
</tbody>
</table>

  - Methane leak loss rate of 0.06% in 2018, well below ONE Future industry and upstream sector targets of 1.00% and 0.28%, respectively, by 2025

    Methane Leak Loss Rate

    | Industry Target | Upstream Sector Target | AR |
    |-----------------|------------------------|----|
    | 1.00%           | 0.28%                  | 0.06% |

Water Management

- Antero Clearwater Facility recycles wastewater and reduces deployment of local trucks by 10 million miles annually, reducing GHG emissions by 30K tons CO2 annually

- Extensive freshwater pipeline network eliminated 790,000 water truck trips in 2018.

- AR receives a Low-Medium Water Risk rating from World Resources Institute

For more information, please visit: [https://www.anteroresources.com/sustainability/](https://www.anteroresources.com/sustainability/)
AR holds 40% of the core undrilled liquids-rich locations in Appalachia and has lower breakeven natural gas price than dry gas producers.
Completion Crew Count is Responding to Price

Completion crew has recently responded to lower natural gas and oil prices with an 11% reduction in active completion crews since April.

Monthly Average U.S. Completion Crews

1Q 2019 NYMEX Henry Hub: $3.15/MMBtu

2Q 2019 NYMEX Henry Hub: $2.64/MMBtu

3Q 2019 NYMEX Henry Hub: $2.23/MMBtu

Source: Completion crews from Primary Vision.
Note: NYMEX Henry Hub price represents natural gas futures settlement history.
AR has hedged approximately 100% and 50% of its expected oil production for 2H 2019 and 2020, respectively, at attractive prices above current strip prices.

**Antero Oil Hedge Profile**

- **WTI Swap Volume (Bbl/d)**: 10,000 Bbl/d
- **Antero WTI Swap Price ($/Bbl)**: $59.25

**Note:** Percentage hedged represents percent of expected oil production hedged based on a 10% CAGR from the midpoint of 2019 production guidance.  
1) Based on hedge position and strip pricing as of 8/30/19.

**~$20 MM Forecasted Hedge Value**

APPENDIX | HEDGES
Capital required to maintain flat production is driven by the base decline rate, which is a function of growth over the prior 12 months, as well as the beginning production level and capital efficiency.

**AR Annual 4Q Decline Rates and Maintenance Capex**

First Year Decline Rate (1)  
Annual Maintenance Capital ($MM) (1)

- **4Q19 production**: 3.2 Bcfe/d  
  - (29%)  
  - ~$700

- **4Q20 production**: 3.6 Bcfe/d  
  - (30%)  
  - ~$750

- **4Q21 production**: 4.0 Bcfe/d  
  - (30%)  
  - ~$900

Antero’s average F&D cost on its 5 year PUD inventory in YE 2018 proved reserve base was $0.44/Mcfe (2)

Note: Based on Antero reservoir engineering team analysis.

1) Represents capital required each year to maintain production at the respective target levels of each year. Decline rate represents Q4 over Q4 change in production.

2) PUD F&D cost is a non-GAAP financial measure. For more information, please see the appendix.
## Antero Capitalization – 6/30/19

<table>
<thead>
<tr>
<th>As of June 30, 2019 ($MM)</th>
<th>Antero Resources</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cash</td>
<td>$0</td>
</tr>
<tr>
<td>Debt</td>
<td></td>
</tr>
<tr>
<td>Revolving Credit Facility</td>
<td>$175</td>
</tr>
<tr>
<td>5.375% Senior Notes Due Nov. 2021</td>
<td>$1,000</td>
</tr>
<tr>
<td>5.125% Senior Notes Due Dec. 2022</td>
<td>$1,100</td>
</tr>
<tr>
<td>5.625% Senior Notes Due Jun. 2023</td>
<td>$750</td>
</tr>
<tr>
<td>5.000% Senior Notes Due Mar. 2025</td>
<td>$600</td>
</tr>
<tr>
<td>Net unamortized premium</td>
<td>$1</td>
</tr>
<tr>
<td>Net unamortized debt issuance costs</td>
<td>($24)</td>
</tr>
<tr>
<td><strong>Total Debt</strong></td>
<td><strong>$3,602</strong></td>
</tr>
<tr>
<td><strong>Net Debt (Total Debt - Cash)</strong></td>
<td><strong>$3,602</strong></td>
</tr>
<tr>
<td>LTM Adjusted EBITDA</td>
<td><strong>$1,589</strong></td>
</tr>
<tr>
<td><strong>Debt / LTM Adjusted EBITDA</strong></td>
<td><strong>2.3x</strong></td>
</tr>
<tr>
<td>Credit Facility Lender Commitments</td>
<td><strong>$2,500</strong></td>
</tr>
<tr>
<td>Liquidity&lt;sup&gt;(1)&lt;/sup&gt;</td>
<td><strong>$1,624</strong></td>
</tr>
</tbody>
</table>

<sup>(1)</sup> Net of $701 million in letters of credit as of June 30, 2019.
Owning and controlling the infrastructure is critical to sustainable development; Antero Midstream provides a customized midstream solution.

**Midstream Ownership Benefits**

- Takeaway assurance and reliable project execution
- Never missed a completion date with fresh water delivery system
- Just-in-time capital investment
- Unparalleled downstream visibility
- Attractive return on investment (3.5x ROI for AR) *(1)*

*(1) ROI reflects cash proceeds received by AR from (1) the sale of AM shares via the AM IPO, (2) proceeds from the water drop down transaction and (3) current market value of AR's ownership in AM as of 8/30/2019, all divided by the capital invested by AR prior to AM’s IPO.*
Appalachia Liquids-Rich Development Fee Analysis

Liquids-rich development requires integrated gathering, compression, and processing infrastructure and requires additional midstream services compared to dry gas development.

Appalachia Liquids-Rich Gathering Through Processing Fee Analysis ($/MMBtu)\(^{(1)}\)

\[
\begin{array}{ccccccccc}
\text{$/MMBtu} & A & B & C & D & E & F & AR/AM & G & H & I \\
\hline
\text{Appalachian Study Average: $1.00/MMBtu} & & & & & & & & & & \\
\$1.20 & & & & & & & & & & \\
\$1.10 & & & & & & & & & & \\
\$1.00 & & & & & & & & & & \\
\$0.90 & & & & & & & & & & \\
\$0.80 & & & & & & & & & & \\
\$0.70 & & & & & & & & & & \\
\$0.60 & & & & & & & & & & \\
\$0.50 & & & & & & & & & & \\
\$0.40 & & & & & & & & & & \\
\$0.30 & & & & & & & & & & \\
\$0.20 & & & & & & & & & & \\
\$0.10 & & & & & & & & & & \\
\$0.00 & & & & & & & & & & \\
\end{array}
\]

Note: Most midstream fees are disclosed on a $/MMBtu basis. AR’s fees are disclosed on a $/Mcf basis and must be converted to a $/MMBtu basis to appropriately compare to others. (i.e. AR fees are divided by 1.25 to account for 1250 BTU gas)

APPENDIX | GATHERING AND COMPRESSION FEES

Note: Excludes dry gas gathering agreements that do not require liquids-rich natural gas processing services. All gathering & compression fees normalized to 1,250 Btu gas, two stage compression and CPI adjusted based on individual contract specifications. Analysis based on public and private company disclosures for Appalachia midstream contracts. Peers include EQT, CNX, MR and private operators.

1. AR’s $1.93/Mcfe GP&T costs in 2Q19 includes costs above plus fractionation, liquids transportation, and long-haul gas transportation on an Mcfe basis over total production (vs. MMBtu basis above for only processed volumes).
Antero Definitions

**Net Debt**: Net Debt is calculated as total debt less cash and cash equivalents. Management uses Net Debt to evaluate its financial position, including its ability to service its debt obligations.

**Proved Undeveloped (PUD) F&D Cost Per Unit**: Proved undeveloped F&D costs per unit is a non-GAAP metric 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. Proved undeveloped F&D costs per unit is a statistical indicator that has limitations, including its predictive and comparative value. This reserve metric may not be comparable to similarly titled measurements used by other companies. There are no directly comparable financial measures presented in accordance with GAAP for proved undeveloped F&D costs per unit, and therefore a reconciliation to GAAP is not practicable.

The calculation for proved undeveloped F&D cost per unit is based on future development costs required for the development of proved undeveloped reserves, divided by total proved undeveloped reserves.
Antero Non-GAAP Measures

Adjusted EBITDAX

Adjusted EBITDAX as defined by the Company represents income or loss, including noncontrolling interests, before interest expense, interest income, gains or losses from commodity derivatives and marketing derivatives, but including net cash receipts or payments on derivative instruments included in derivative gains or losses other than proceeds from derivative monetizations, income taxes, impairment, depletion, depreciation, amortization, and accretion, exploration expense, equity-based compensation, gain or loss on early extinguishment of debt, gain or loss on sale of assets, gain or loss on changes in the fair value of contingent acquisition consideration, contract termination and rig stacking costs, and equity in earnings or loss of Antero Midstream. Adjusted EBITDAX also includes distributions received from limited partner interests in Antero Midstream common units prior to the closing of the simplification transaction on March 12, 2019.

The GAAP financial measure nearest to Adjusted EBITDAX is net income or loss including noncontrolling interest that will be reported in Antero’s condensed consolidated financial statements. While there are limitations associated with the use of Adjusted EBITDAX described below, management believes that this measure is useful to an investor in evaluating the Company’s financial performance because it:

- is widely used by investors in the oil and gas industry to measure a company’s operating performance without regard to items excluded from the calculation of such term, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired, among other factors;
- helps investors to more meaningfully evaluate and compare the results of Antero’s operations from period to period by removing the effect of its capital structure from its operating structure; and
- is used by management for various purposes, including as a measure of Antero’s operating performance, in presentations to the Company’s board of directors, and as a basis for strategic planning and forecasting. Adjusted EBITDAX is also used by the board of directors as a performance measure in determining executive compensation.

There are significant limitations to using Adjusted EBITDAX as a measure of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect the Company’s net income, the lack of comparability of results of operations of different companies and the different methods of calculating Adjusted EBITDAX reported by different companies. In addition, Adjusted EBITDAX provides no information regarding a company’s capital structure, borrowings, interest costs, capital expenditures, and working capital movement or tax position.
Adjusted Net Cash Provided by Operating Activities and Free Cash Flow

Adjusted Net Cash Provided by Operating Activities as presented in this presentation represents net cash provided by operating activities excluding net cash provided by operating activities from Antero Midstream Partners consolidated from January 1, 2019 through March 12, 2019. Adjusted Net Cash Provided by Operating Activities is widely accepted by the investment community as a financial indicator of an oil and gas company’s ability to generate cash to internally fund exploration and development activities and to service debt. Adjusted Net Cash Provided by Operating Activities is also useful because it is widely used by professional research analysts in valuing, comparing, rating and providing investment recommendations of companies in the oil and gas exploration and production industry. In turn, many investors use this published research in making investment decisions. Free Cash Flow as defined by the Company represents Adjusted Net Cash Provided by Operating Activities, less drilling and completion capital, less drilling and completion capital paid to Antero Midstream Partners from January 1 to March 12, 2019, less land capital.

There are significant limitations to using Adjusted Net Cash Provided by Operating Activities and Free Cash Flow as measures of performance, including the inability to analyze the effect of certain recurring and non-recurring items that materially affect the company’s net income, the lack of comparability of results of operations of different companies and the different methods of calculating Adjusted Net Cash Provided by Operating Activities and Free Cash Flow reported by different companies. Adjusted Net Cash Provided by Operating Activities and Free Cash Flow do not represent funds available for discretionary use because those funds may be required for debt service, land acquisitions and lease renewals, other capital expenditures, working capital, income taxes, exploration expenses, and other commitments and obligations.

Adjusted Net Cash Provided by Operating Activities and Free Cash Flow are not measures of financial performance under GAAP and should not be considered in isolation or as a substitute for cash flows from operating, investing, or financing activities, as an indicator of cash flows, or as a measure of liquidity. Furthermore, we may calculate such measures differently from similarly titled measures used by other companies.
# LTM Adjusted EBITDAX Reconciliation

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount</th>
</tr>
</thead>
<tbody>
<tr>
<td>Net income and comprehensive income attributable to Antero Resources Corp.</td>
<td>$744,966</td>
</tr>
<tr>
<td>Commodity derivative fair value gains</td>
<td>$(85,692)</td>
</tr>
<tr>
<td>Gains on settled commodity derivatives</td>
<td>$187,678</td>
</tr>
<tr>
<td>Marketing derivative fair value gains</td>
<td>$43</td>
</tr>
<tr>
<td>Losses on settled marketing derivatives</td>
<td>$(21,471)</td>
</tr>
<tr>
<td>Gain on sale of assets</td>
<td>$951</td>
</tr>
<tr>
<td>Gain on deconsolidation of Antero Midstream Partners LP</td>
<td>$(1,406,042)</td>
</tr>
<tr>
<td>Interest expense</td>
<td>$226,390</td>
</tr>
<tr>
<td>Income tax expense</td>
<td>$193,555</td>
</tr>
<tr>
<td>Depletion, depreciation, amortization, and accretion</td>
<td>$909,012</td>
</tr>
<tr>
<td>Impairment of unproved properties</td>
<td>$567,707</td>
</tr>
<tr>
<td>Exploration expense</td>
<td>$2,042</td>
</tr>
<tr>
<td>Gain on change in fair value of contingent acquisition consideration</td>
<td>$100,840</td>
</tr>
<tr>
<td>Equity-based compensation expense</td>
<td>$34,167</td>
</tr>
<tr>
<td>Equity in (earnings) loss of Antero Midstream Partners LP</td>
<td>$(58,411)</td>
</tr>
<tr>
<td>Equity in (earnings) loss of unconsolidated affiliates</td>
<td>$(15,402)</td>
</tr>
<tr>
<td>Distributions from Antero Midstream Partners LP</td>
<td>$178,925</td>
</tr>
<tr>
<td>Contract termination and rig stacking</td>
<td>$13,964</td>
</tr>
<tr>
<td>Simplification transaction fees</td>
<td>$6,297</td>
</tr>
<tr>
<td>Adjusted EBITDAX</td>
<td>$1,588,519</td>
</tr>
<tr>
<td>AR bank credit facility</td>
<td>$175,000</td>
</tr>
<tr>
<td>5.375% AR senior notes due 2021</td>
<td>$1,000,000</td>
</tr>
<tr>
<td>5.125% AR senior notes due 2022</td>
<td>$1,100,000</td>
</tr>
<tr>
<td>5.625% AR senior notes due 2023</td>
<td>$750,000</td>
</tr>
<tr>
<td>5.000% AR senior notes due 2025</td>
<td>$600,000</td>
</tr>
<tr>
<td>Net unamortized premium</td>
<td>$1,095</td>
</tr>
<tr>
<td>Net unamortized debt issuance costs</td>
<td>$(23,716)</td>
</tr>
<tr>
<td>Total debt</td>
<td>$3,602,379</td>
</tr>
<tr>
<td>Less: AR cash and cash equivalents</td>
<td>—</td>
</tr>
<tr>
<td>Net Debt</td>
<td>$3,602,379</td>
</tr>
</tbody>
</table>
### Antero Resources Net Debt to EBITDAX

#### Net Debt to Adjusted EBITDAX Reconciliation (Annual)

<table>
<thead>
<tr>
<th></th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>2Q19</th>
</tr>
</thead>
<tbody>
<tr>
<td>$ Millions</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Debt</td>
<td>$4,248</td>
<td>$4,082</td>
<td>$3,890</td>
<td>$3,635</td>
<td>$3,855</td>
<td>$3,602</td>
</tr>
<tr>
<td>Less: Cash</td>
<td>(16)</td>
<td>(17)</td>
<td>(18)</td>
<td>(20)</td>
<td>--</td>
<td>--</td>
</tr>
<tr>
<td>Net Debt</td>
<td>$4,232</td>
<td>$4,065</td>
<td>$3,872</td>
<td>$3,615</td>
<td>$3,855</td>
<td>$3,602</td>
</tr>
<tr>
<td>Production Volumes (Bcfe)</td>
<td>368</td>
<td>545</td>
<td>676</td>
<td>822</td>
<td>989</td>
<td>294</td>
</tr>
<tr>
<td>$ Millions</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Natural Gas, Oil, Ethane and NGL sales</td>
<td>$1,741</td>
<td>$1,379</td>
<td>$1,757</td>
<td>$2,751</td>
<td>$3,659</td>
<td>$906</td>
</tr>
<tr>
<td>Realized commodity derivative (losses)</td>
<td>136</td>
<td>857</td>
<td>1,003</td>
<td>214</td>
<td>243</td>
<td>45</td>
</tr>
<tr>
<td>Distributions from Antero Midstream</td>
<td>89</td>
<td>112</td>
<td>132</td>
<td>159</td>
<td>48</td>
<td></td>
</tr>
<tr>
<td><strong>All-In Revenue</strong></td>
<td><strong>$1,877</strong></td>
<td><strong>$2,324</strong></td>
<td><strong>$2,872</strong></td>
<td><strong>$3,097</strong></td>
<td><strong>$4,061</strong></td>
<td></td>
</tr>
<tr>
<td>Gathering, compression, processing, and transportation</td>
<td>537</td>
<td>853</td>
<td>1,146</td>
<td>1,441</td>
<td>1,793</td>
<td>567</td>
</tr>
<tr>
<td>Production and ad valorem taxes</td>
<td>86</td>
<td>77</td>
<td>69</td>
<td>91</td>
<td>122</td>
<td>31</td>
</tr>
<tr>
<td>Lease operating expenses</td>
<td>28</td>
<td>36</td>
<td>51</td>
<td>94</td>
<td>142</td>
<td>41</td>
</tr>
<tr>
<td>Net Marketing Expense / (Gain)</td>
<td>50</td>
<td>123</td>
<td>106</td>
<td>108</td>
<td>154</td>
<td>74</td>
</tr>
<tr>
<td>General and administrative (before equity-based compensation)</td>
<td>86</td>
<td>108</td>
<td>110</td>
<td>119</td>
<td>132</td>
<td>36</td>
</tr>
<tr>
<td><strong>Total Cash Costs</strong></td>
<td><strong>$786</strong></td>
<td><strong>$1,196</strong></td>
<td><strong>$1,483</strong></td>
<td><strong>$1,853</strong></td>
<td><strong>$2,344</strong></td>
<td><strong>$749</strong></td>
</tr>
<tr>
<td>Adjusted EBITDAX</td>
<td><strong>$1,091</strong></td>
<td><strong>$1,128</strong></td>
<td><strong>$1,384</strong></td>
<td><strong>$1,244</strong></td>
<td><strong>$1,717</strong></td>
<td><strong>$252</strong></td>
</tr>
<tr>
<td>Net Debt to Adjusted EBITDAX</td>
<td>3.9x</td>
<td>3.6x</td>
<td>2.8x</td>
<td>2.9x</td>
<td>2.2x</td>
<td>2.3x</td>
</tr>
</tbody>
</table>