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 AR 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, 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, future financial position, the amount and timing of any litigation settlements or awards, future technical improvements, future marketing and asset monetization opportunities, the amount and timing of any contingent payments, AR’s environmental goals, the consummation of the December 2020 senior notes offering and the use of proceeds therefrom, including the partial, contingent redemption of the 2022 senior notes, 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 the development, production, gathering and sale of natural gas, NGLs and oil, most of which are difficult to predict and many of which are beyond 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, impacts of world health events, including the COVID-19 pandemic, potential shut-ins of production due to lack of downstream demand or storage capacity, 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, 2019 and its Quarterly Report on Form 10-Q for the quarter ended September 30, 2020.

This presentation includes certain financial measures that are not calculated in accordance with U.S. generally accepted accounting principles (“GAAP”). These measures include (i) Net F&D cost, (ii) leverage and (iii) Free Cash Flow. Please see “Antero Non-GAAP Measures” for the definition as well as certain additional information regarding each measure.

References in this presentation to our December 2020 senior notes offering are to our $500 million offering of senior notes due 2026, which is expected to close January 4, 2021. References to our $350 million redemption of senior notes due 2022 are to the partial redemption of the 2022 notes using a portion of the proceeds from the December 2020 senior notes offering, which redemption is expected to occur on January 16, 2021 and is contingent upon the closing of the December 2020 senior notes offering.

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.
Executive Summary

Asset Overview

Natural Gas & NGL Macro

Appendix
Denver, CO
HEADQUARTERS

S&P 400
CONSTITUENT

3rd Largest
U.S. GAS PRODUCER

2nd Largest
U.S. NGL PRODUCER

Own 40%
OF CORE LIQUIDS-RICH UNDRILLED LOCATIONS IN APPALACHIA

1,200
ADDITIONAL DRY GAS LOCATIONS IN DRILLING INVENTORY

~93% Hedged
ON NATURAL GAS THROUGH 2021 @ $2.78/MMBtu

29% Midstream
AM VALUE HELD BY AR $1.1 B

Note: Hedge position as of 9/30/20. Rigs on map as of 12/15/20, per Rig data. AM value based on 12/18/20 share price.
1) Natural gas and NGL rankings based on 3Q20 reported production.
2) AR drilling inventory as of 6/30/20. Industry location count based on Antero analysis of undeveloped acreage in the core of the Marcellus and Ohio Utica Shales.
Addressing Senior Note Maturities

Antero has closed $751 MM in asset sales and $788 MM (1) in refinancing to date to reduce 2021-2023 debt maturities and deleverage

Announced Asset Sale Program with AM share sale (December 2019)
$100 MM AM share sale

ORRI Transaction with Sixth Street Partners (June 2020)
$402 MM in proceeds (1)

Hedge Monetization (July 2020)
$29 MM monetization

VPP with J.P. Morgan (August 2020)
$220 MM VPP sale to an affiliate of JPM

Convertible Senior Notes Offering (August 2020)
$288 MM in proceeds

Antero has closed $751 MM in asset sales and $788 MM (1) in refinancing to date to reduce 2021-2023 debt maturities and deleverage

$750 MM - $1 B Asset Sale Target Range

1) Includes two $51 MM contingent payments, the first of which was received in December 2020 and the second of which is expected to be received in 2Q 2021 if certain volume thresholds are met.

2) Pro forma for December 2020 senior notes offering and subsequent $350 MM redemption of senior notes due 2022.
Much Improved Senior Note Term Structure

Unsecured Debt Maturity Summary (Pro forma for the December 2020 senior notes offering and partial redemption of 2022s):

- Eliminated ~$2.0 B of near term maturities: $1.3 B of open market repurchases and tenders, $313 MM redemption of 2021 senior notes and $350 MM redemption of 2022 senior notes

**AR 9/30/19 Senior Note Maturity Schedule ($MM)**

<table>
<thead>
<tr>
<th>Year</th>
<th>Note Maturity</th>
<th>Par Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>2020</td>
<td>5.375% Nov 2021</td>
<td>$1,000</td>
</tr>
<tr>
<td>2021</td>
<td>5.125% Dec 2022</td>
<td>$1,100</td>
</tr>
<tr>
<td>2022</td>
<td>5.625% Jun 2023</td>
<td>$750</td>
</tr>
<tr>
<td>2024</td>
<td>4.250% Sep 2026</td>
<td>$500</td>
</tr>
<tr>
<td>2025</td>
<td>8.375% Jul 2026</td>
<td>$500</td>
</tr>
<tr>
<td>2026</td>
<td></td>
<td>$0</td>
</tr>
</tbody>
</table>

**AR Pro Forma 9/30/2020 Senior Note Maturity Schedule ($MM)**

- Remaining senior notes due 2021 have been redeemed

Pro forma for redemption of $350MM of 2022 senior notes using proceeds from the December 2020 senior note offering
Impressive Operational Momentum

**Lowered 2020 Capital Budget to $750 MM**
- Revised D&C capital budget to $750 MM in 2020, a 35% decrease from initial 2020 guidance and a 41% decrease from 2019 spending
- 2020 production growth guidance of 8% with ~$175 MM - $200 MM of estimated 2H 2020 Free Cash Flow \(^1\)
- $580 MM D&C capital expected to hold production flat in 2021

**Reduced Cost Structure**
- 30% well cost reduction from January 2019 budget to $675/lateral foot expected in 2H 2020 \(^2\)
- >80% of well cost reductions were driven by process changes and cycle time efficiencies
- Total of ~$616 MM in capital and operating cost savings expected in 2020 relative to 2019 initial budget

---

1) Free Cash Flow is a non-GAAP measure. See appendix for more information.
2) Well costs include ~$1 MM or ~$80/ft for facilities, pads and road costs per well assuming a 12,000’ lateral.
3) Maintenance capital assumes $671/ft well cost and 13,000’ laterals.
The improvement in NGL pricing, combined with a significant reduction in capital and operating costs, is expected to result in $175 - $200 MM in Free Cash Flow in 2H 2020.

2H 2020 Pricing & Production

- Fully hedged on natural gas production at $2.83 / MMBtu
- C3+ NGL strip prices up 25%+ compared to 1H 2020 (~$5+/Bbl)
- 3.5 Bcfe/d 2H 2020 production (based on annual guidance)

2H 2020 Capital

- $280 MM Capital in 2H 2020 ($260 MM D&C and $20 MM Land)
- $230 MM reduction in capital from 1H 2020

$175 - $200 MM
2H 2020 Free Cash Flow (1)

---

1) Free Cash Flow is a non-GAAP term. See appendix for more information, including certain material assumptions in projecting Free Cash Flow.
As one of the largest natural gas and NGL producers in the U.S., Antero has significant cash flow upside in a rising commodity price environment.

Top 5 U.S. Natural Gas Producers (MMcf/d)

- EQT: 3,784 MMcf/d
- XOM: 2,611 MMcf/d
- AR: 2,453 MMcf/d
- COG: 2,406 MMcf/d
- SWN: 1,880 MMcf/d

Top 5 U.S. NGL Producers (MBbls/d)

- OXY: 212 MBbls/d
- AR: 205 MBbls/d
- EOG: 140 MBbls/d
- DVN: 123 MBbls/d
- PXD: 122 MBbls/d

AR Leverage to Natural Gas Prices ($MM) (1)

- Every $0.10 per MMBtu move in natural gas prices results in an $90 MM unhedged annual revenue impact (1)

AR Leverage to C3+ NGL Prices ($MM) (2)

- Every $2 per Bbl move in C3+ NGL prices results in a $106 MM unhedged annual revenue impact (2)

Note: Natural gas and NGL producer rankings reflect company 3Q20 reports and public filings. Pro forma for all announced acquisitions to date.

1) Assumes 3Q2020 natural gas production of 2.453 Bcf/d. Note: 2.2 Bcf/d of AR natural gas volumes are hedged through 2021 at a weighted average of $2.82/MMBtu.

2) Assumes 3Q2020 C3+ NGL production of 131 MBbl/d.
Positive Natural Gas and NGL Price Momentum

Natural gas and NGL prices expected to strengthen over the coming quarters as global demand increases while supply flattens (assuming current oil price strip)

**U.S. Natural Gas**

**Supply**
- 3.0 Bcf/d reduction from 2019 to 90 Bcf/d and 7.0 Bcf/d aggregate reduction expected in 2021 due to decline in “associated gas” from shale oil basins with ~$45/Bbl WTI oil (Permian, Eagle Ford, SCOOP/STACK, Bakken)
- Flat production from gas producers who will stick to capital discipline
- High Storage of 3.9 Tcf at end of injection season in November but low storage of 1.5 Tcf expected for end of withdrawal season in April 2021

**Demand**
- LNG feedgas demand has recovered from summer cancellations to over 11 Bcf/d today. LNG exports expected to remain above 11 Bcf/d into year end with $10+/MMBtu JKM pricing
- Mexican exports up 18% YoY to 6 Bcf/d
- U.S. demand has remained steady YoY at 75 Bcf/d

**Outlook for Natural Gas**
- Bullish - $2.76 strip for 2021 with rising 2022 prices due to growing demand and flat supply

**U.S. NGLs**

**Supply**
- U.S. NGL production projected to decline by 1 MMBbl/d relative to forecast by YE 2021, driven by decline in associated gas and the “associated NGLs” in shale oil basins
- International NGL production “associated” with OPEC oil production decreased due to OPEC+ supply cut
- Lower global refinery utilization results in a decline in refinery NGLs supply as a byproduct of oil refining

**Demand**
- Resilient domestic and international demand from petrochem and residential/commercial sectors
- Rising living standards in developing countries create an inelastic demand pull for NGL products
- Asian economies recovering from COVID-19 pandemic and Chinese tariffs on LPG were lifted in early 2020

**Outlook for NGLs**
- The impact of the decline in shale oil activity on “associated NGL” supply is expected to be even more pronounced than the impact on associated gas supply while global LPG demand of ~ 10 MMBbl/d remains stable
- Bullish – Resilient demand and declining supply has already driven C3+ pricing from $15/Bbl in 2Q 2020 to over $29/Bbl today

Sources: September EIA Short Term Energy Outlook, S&P Global Platts estimates and J.P. Morgan Commodities Strategy Team Research. LPG is comprised of NGL components propane and butane.
Leading Sustainability and ESG Metrics

2025 Goals

Continued Environmental Improvement

- **50% Reduction** in already low methane leak loss rate to under 0.025% by 2025
- **10% Reduction** in GHG Intensity by 2025
- **Endeavor to Achieve Net Zero Carbon Emissions** by 2025
- **Align with TCFD and SASB Guidelines in meantime**

One of the Lowest GHG Emission Intensity Metrics in the Industry in 2019

- 100% of Fresh Water Used was Transported by Pipeline
- 88% of Total Produced Water Generated was Reused in 2020

One of the Lowest Methane Leak Loss Rates in the Industry

- Water Pipeline Eliminated 590,000 Truck Trips in 2019
- 41% of Total Water Used is Recycled and Reused Water YTD 2020

Near Zero Natural Gas Flaring

0.026 Lost Time Incident Rate in 2019, one of the Lowest in the Industry

7,556 Employee Safety Training Hours
Executive Summary

Asset Overview

Natural Gas & NGL Macro

Appendix
Energy Industry Realities

- Commodity prices are cyclical
- Energy is a capital intensive business
- Long-term planning & execution are critical

Commodity Price Risk

- Opportunistically Hedge Commodities ~93% hedged on natural gas through 2021 at $2.78/MMBtu (1)
- Utilize Firm Transport - substantially reduces basis risk in an increasingly tight Appalachia takeaway capacity
- Drive leverage lower & improve financial flexibility

Capital Intensity

- Develop highest rate of return locations across asset portfolio while maintaining flat production profile
- Drive down capital and operating costs to maximize free cash flow

Execution

- Integrated upstream and midstream planning process to generate synergies, maximize utilization and minimize operational downtime
- Stress test commodity prices and maintain multiple development plan scenarios
- Base compensation on plan execution and peer-leading ESG performance

1) Percentage hedged represents percent of expected natural gas production hedged based on natural gas production guidance of 2.375 Bcf/d in 2020 and flat production in 2021.
AR Business Strategy

Antero Resources Principles

Build Scale with Natural Gas & Liquids Diversification

Maintain Strong Balance Sheet and Financial Flexibility

Mitigate Commodity Price Risk With Hedges and Firm Transportation

Priorities

1. Balance capital spending with cash flow

2. Maintain liquidity & strengthen balance sheet with medium term leverage target below 2-times

3. Develop highest rate of return locations across asset portfolio

4. Use hedges and firm transport to protect cash flow and balance sheet

Tied to management & employee compensation plan metrics

Note: Leverage is a non-GAAP financial measure. Please see the appendix for more information.
Drilling and completion efficiencies and midstream cost savings are expected to result in approximately $616 million of savings in 2020 compared to AR’s 2019 initial budget

**Cost Savings Update**

**Well Cost Reduction Progress**

- 2020 D&C of $705/lateral foot, a 27% reduction from $970/ft at the beginning of 2019
- $750 MM revised D&C capital budget for 2020, a ~$400 MM reduction from the initial 2020 budget and 41% below 2019, with no change to production guidance

**Water Savings Driving LOE Lower**

- 3Q20 represented a 54% reduction from 2019
- Expect to save $90 MM in 2020 as a result of increased blending operations combined with reduced trucking costs

**GP&T and Net Marketing Expense Reduction**

- $68 MM of midstream fee reductions in 2020 with Antero Midstream and other third party midstream providers
- Targeting $100 MM reduction in 2020 net marketing expense (1)

**G&A Cost Reduction**

- 18% reduction due to headcount reductions in 2019, natural employee attrition and a reduction across the board in expenses

**2020 Savings** (1)

- $334 MM ($970/ft - $705/ft) x 12,000’ = $3.18 MM
- $3.18 MM per well x 105 wells = $334 MM

+ $90 MM ~54% reduction from 2019

+ $168 MM

+ $24 MM

Grand Total Cost Reset for 2020 = ~$616 MM

Note: Cost reductions are based on 2020 guidance vs original 2019 guidance

1) Based on midpoint 2020 guidance.
Balance Capex with Cash Flow – Drilling & Completion Efficiencies

**Average Lateral Length per Well**

- 2014: 6,017
- 2015: 6,017
- 2016: 6,017
- 2017: 6,017
- 2018: 6,017
- 2019: 6,017
- YTD 2020: 6,017
- **Achieved March 2020:** 11,253
- **Record:** New U.S. Record

**Lateral Drilling Feet per Day**

- 2014: 5,934
- 2015: 6,209
- 2016: 6,484
- 2017: 6,991
- 2018: 7,265
- 2019: 7,265
- YTD 2020: 7,265
- **Achieved June 2020:** 11,253
- **Record:** New U.S. Record

**Completion Stages per Day**

- 2014: 5.8
- 2015: 8.0
- 2016: 13.0
- 2017: 25.0
- 2018: 25.0
- 2019: 25.0
- YTD 2020: 25.0
- **Achieved April 2020:** 13.0
- **Record:** New U.S. Record

**Drill Out Feet per Day**

- 2014: 979
- 2015: 1,430
- 2016: 1,772
- 2017: 1,781
- 2018: 2,795
- 2019: 2,795
- YTD 2020: 2,795
- **Achieved March 2020:** 6,017
- **Record:** New U.S. Record

Note: Percentage increase and decrease arrows represent change in Marcellus data from 2014 through YTD 2020 (through September 2020).
### Maintenance Capital Calculation

- The average AR rich Marcellus well produces 3.27 Bcfe net in the calendar year when brought online mid-year.
- Assume new wells average ½ year of production.

Production can be held flat with ~65 wells:

213 Bcfe ÷ 3.27 Bcfe per well = 65.1 wells

**Maintenance D&C Capital**

65 wells $8.7 MM per well = **$566 MM**

---

### Field and Operating Capital

- Roads
- Working interest optimization
- Pad construction costs

**Maintenance Field Capital:**

~$14 MM

---

### Antero Average Development Well

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Avg. Lateral Length per Well</td>
<td>13,000'</td>
</tr>
<tr>
<td>Bcfe/1,000’</td>
<td>2.71</td>
</tr>
<tr>
<td>Wellhead Gas BTU</td>
<td>1265</td>
</tr>
<tr>
<td>Well Cost ($671/ft)</td>
<td>$8.7 MM</td>
</tr>
<tr>
<td>Net F&amp;D Cost</td>
<td>$0.305/Mcfe</td>
</tr>
<tr>
<td>C2 Recovery (1)</td>
<td>35% to 40%</td>
</tr>
<tr>
<td>Well Spacing</td>
<td>830'</td>
</tr>
</tbody>
</table>

### First Year Recovery Volumes

<table>
<thead>
<tr>
<th>Description</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gross (Bcfe)</td>
<td>6.42</td>
</tr>
<tr>
<td>Net (Bcfe)</td>
<td>5.16</td>
</tr>
</tbody>
</table>

---

Note: Maintenance capital is net of ORRI transaction and VPP transaction. Net F&D cost assumes 81% net revenue interest.

1) Reflects increased ethane volume with start up of Shell Cracker in 2021. Ethane sold at a premium to natural gas price.
Through a combination of proceeds from the December 2020 senior notes offering, Free Cash Flow and the ORRI contingent payment, AR is expected to have more than sufficient liquidity to repay the December 2022 bond maturity.

### AR Year-End 2020E Liquidity Relative to Remaining 2022 Bond Maturity ($MM)

<table>
<thead>
<tr>
<th>Description</th>
<th>Amount ($MM)</th>
</tr>
</thead>
<tbody>
<tr>
<td>9/30/2020 Liquidity</td>
<td>$1,083</td>
</tr>
<tr>
<td>2021 Senior Notes Redemption</td>
<td>$313</td>
</tr>
<tr>
<td>ORRI Contingent Payment</td>
<td>$102</td>
</tr>
<tr>
<td>4Q 2020E Free Cash Flow</td>
<td>$180</td>
</tr>
<tr>
<td>Net Proceeds From Dec-20 Offering</td>
<td>$144</td>
</tr>
<tr>
<td>Pro Forma 12/31/2020E Liquidity</td>
<td>$1,196</td>
</tr>
<tr>
<td>Remaining 2022 Senior Notes Par Value</td>
<td>$311</td>
</tr>
</tbody>
</table>

**Notes:**

1. Liquidity represents borrowing availability under AR’s credit facility based on $2.64 B of lender commitments, $730 MM of letters of credit and $827 MM of borrowings as of 9/30/2020.
2. Includes $102 million of contingent payments, $51 million of which was earned based on volume thresholds met during the third quarter of 2020. The remainder may be earned based on achieving volume thresholds through the first quarter of 2021, which has been included for comparison purposes to outstanding 2022 bonds.
4. Proceeds are net of redemption of $350 MM of senior notes due 2022 and include initial purchaser’s discount and expected legal, auditor and aggregate rating agency fees that total $6 million.
### Develop Highest ROR Locations

#### AR Resource Overview

**Large Delineated Drilling Inventory**
- Diverse set of locations
- AR holds ~1,400 liquids-rich locations, or 40% of the core undrilled liquids-rich locations in Appalachia
- ~1,200 undrilled dry gas locations

**Contiguous Acreage Position Delivers Efficient Development**
- Long-laterals average 12,100’ in Marcellus rich-gas drilling inventory
- Efficient gathering, compression and processing utilization, and water re-use opportunities generates synergies and capital savings

**High Working Interest and Net Revenue Interest**
- ~1,000 horizontal Marcellus producing wells are 100% operated and have 99% average working interest
- AR has 83% average PDP NRI in the Marcellus, 81% development NRI for the next three years and 84% thereafter (1)

---


1) Net revenue interest (NRI): Net of ORRI transaction. Assumes Antero achieves production thresholds under ORRI agreement generating contingent payments and satisfying development commitments.
Antero currently recovers only 30% of the ethane in its rich gas stream while rejecting 70% of the ethane, sending it to pipeline sales in the natural gas stream.

**Antero NGL Barrel Composition (2020 Guidance)**

- Ethane (C2) ~55,000 Bbl/d
- Propane (C3) 56%
- Normal Butane (C4) 17%
- IsoButane (iC4) 10%
- Pentanes (C5+) 17%

**AR’s C2+ NGL Barrel Composition**

- Ethane ~55,000 Bbl/d (30% of Barrel)
- C3+ NGLs ~123,000 Bbl/d (70% of Barrel)

**AR’s C3+ NGL Barrel Composition**

- Propane (C3) 56%
- Normal Butane (C4) 17%
- IsoButane (iC4) 10%
- Pentanes (C5+) 17%

**Note:** Based on Antero 2020 production guidance. Antero C3+ NGL component barrel consists of 56% C3 (propane), 10% isobutane (iC4), 17% normal butane (Nc4) and 17% natural gasoline (C5+).
**Producer Disadvantaged:**
E&Ps in Permian, Rockies, Mid-Con & Bakken

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**Producer Advantaged & Unconstrained:**
Antero Resources in Appalachia

---

AR is the largest C3+ producer with the most international exposure in Appalachia

---

**Who Captures the Arb at Marcus Hook?**

- **Answer:** AR and other Appalachian E&P’s
  - Direct sales to most attractive international (ARA & FEI) & domestic markets
  - Fixed terminal rates
  - Local fractionation & marketing to sell purity products in-basin for local demand

  **Results in “Mont Belvieu plus” pricing netbacks captured “at the dock” by AR**

---

**Who Captures the Arb at the Gulf Coast?**

- **Answer:** Midstream & LPG off-takers (not E&P’s)
  - No direct E&P access to international markets (i.e. producers only receive Mont Belvieu linked pricing)
  - No local fractionation to sell marketable purity products in-basin

  **Results in “Mont Belvieu Minus” pricing “before the dock”**
Diversified exposure to both international and domestic markets results in Antero realizing a premium to Mont Belvieu on its C3+ NGL pricing.

### Antero 2020 C3+ NGL Pricing Outlook (1)

<table>
<thead>
<tr>
<th>Sales Point</th>
<th>Domestic %</th>
<th>International %</th>
<th>Combined %</th>
</tr>
</thead>
<tbody>
<tr>
<td>Hopedale</td>
<td>50%</td>
<td>Marcus Hook</td>
<td>100%</td>
</tr>
<tr>
<td>Expected Premium / (Discount) to Mont Belvieu ($/Gal)</td>
<td>$0.00 - $0.05</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

1) Based on Antero C3+ NGL component barrel consisting of 56% C3 (propane), 10% isobutane (IC4), 17% normal butane (NC4) and 17% natural gasoline (C5+).
AR’s C3+ NGL Barrel Spot Pricing

Weekly Benchmark Index Pricing as of 12/21/20 – Net of Shipping

This data reflects benchmark pricing estimates and does not directly reflect Antero’s realized prices or hedges.

Assumes 2020 AR C3+ NGL Volumes of 118,000 Bbl/d

- Propane (C3): 56% (~62 MBbl/d)
  - Global Weighted C3/C4 Average Price: $32.05/Bbl
  - Mont Belvieu Non-Tet
    - Propane: $0.64/gal (27,580 Bbl/d)
    - N. Butane: $0.86/gal (3,560 Bbl/d)
    - IsoButane: $0.68/gal (11,800 Bbl/d)
    - Pentanes: $1.02/gal (20,060 Bbl/d)
    - Total: $28.57/Bbl

Antero Estimated Domestic Sales
100% Mont Belvieu Linked

Antero Estimated International Sales
38.5 Mb/d C3, 16.5 Mb/d C4
(Assumes 50% ARA, 50% FEI)

- 50% Europe (ARA) Net of Shipping
  - Propane: $0.70/gal (19,250 Bbl/d)
  - Butane: $0.84/gal (8,250 Bbl/d)

- 50% Asia (FEI) Net of Shipping
  - Propane: $0.76/gal (19,250 Bbl/d)
  - Butane: $0.86/gal (8,250 Bbl/d)

Weekly Indicated Weighted Average Price:

- 1Q20: $21.31
- 2Q20: $15.55
- 3Q20: $22.50
- 4QTD: $26.86
- Current: $30.20

Domestic Weighted Average Price: $28.57/Bbl

Shipping rates assumed are detailed on pages 2 and 3 of Antero’s Weekly International LPG Pricing Update presentation. Please see Antero website for more information.

1) Assumes midpoint of Antero guidance for domestic price discount to Mont Belvieu of $0.10/gal.
2) Weighted average assumes 55 MBbl/d international and 63 MBbl/d domestic.
3) Excludes Antero Hedges.
4) Weighted average assumes 55 MBbl/d international and 63 MBbl/d domestic.
5) Quarter to date calculation reflects latest average of Weekly Indicated Weighted Average Price published on page 4 of Antero’s weekly international LPG Pricing Update presentation.
NGL prices have risen on an absolute basis and relative to WTI since March/April lows.

AR Monthly Realized C3+ NGL Price

Source: Bloomberg actuals through November 2020. Forecasted C3+ pricing based ICE pricing and on Antero C3+ NGL component barrel consisting of 56% C3 (propane), 10% isobutane (iC4), 17% normal butane (nC4) and 17% natural gasoline (C5+). Assumes blended sales of 50% domestic and 50% international.
Antero’s average unhedged half cycle rate of return for its near-term development program areas is 58%.

### Antero Half Cycle Well Economics by BTU Regime

<table>
<thead>
<tr>
<th>BTU Regime</th>
<th>Pre-tax Rate of Return (ROR)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Marcellus - Highly Rich Gas 1250 BTU</td>
<td>60%</td>
</tr>
<tr>
<td>Utica - Dry Gas 1050 BTU</td>
<td>59%</td>
</tr>
<tr>
<td>Marcellus - Highly Rich Gas 1225 BTU</td>
<td>58%</td>
</tr>
<tr>
<td>Marcellus - High Rich Gas 1275 BTU</td>
<td>57%</td>
</tr>
<tr>
<td>Marcellus - Highly Rich Gas 1215 BTU</td>
<td>53%</td>
</tr>
<tr>
<td>Utica - Highly Rich Gas/Condensate 1235 BTU</td>
<td>45%</td>
</tr>
</tbody>
</table>

**2020 + 2021 Weighted Average: 58%**

---

Note: Assumptions 9/30/2020 strip pricing. Half cycle burdened, post-ORRI with 71% of AM fee, variable FT costs and no charge for G&A or land. Assumes 13,000' lateral lengths, 180 days spud to 1st sales and 2,000 lb/ft completions.
Antero has some of the lowest natural gas breakeven prices in Appalachia as highlighted in a recent JP Morgan research report.

2021-2022 Natural Gas Unhedged Breakevens - 15% ROR Full Cycle Breakeven Prices

Breakeven analysis source: J.P. Morgan Equity Research estimates in December 8, 2020 report.

1) Breakeven price is defined as full cycle pre-tax ROR of 15%.
2) Assumes average WTI price of $45.22/Bbl and $44.63/Bbl in 2021 and 2022, respectively. J.P. Morgan assumed Antero C3+ NGL price of $26.67/Bbl and $24.78/Bbl in 2021 and 2022, respectively.
Antero is very well hedged on its forecast natural gas production through 2021

Antero Natural Gas Hedge Profile (1)

Hedge Commodities - Natural Gas Price Exposure Mitigated Through 2021

---

Note: Percentage hedged represents percent of expected natural gas production hedged based on natural gas production guidance of 2.375 Bcf/d in 2020 and assuming maintenance level capital and flat production in 2021 and 2022.

1) Strip pricing and hedge position as of 12/18/2020.
4.2 Bcf/d Firm Gas Takeaway

Midwest Markets

- 25 MBbl/d Ethane
- 30 MBbl/d Ethane
- In Service 2H 2022
- 525 MMcf/d
- Gulf East
- TCO Pool
- 9%
- Atlantic Seaboard
- 51%
- Maritime
- 13%
- Regional
- 19%
- Midwest
- 51%
- Gulf Coast
- 370 MMcf/d

Regional Markets

- 22 MBbl/d Ethane Export
- Marcus Hook
- 55 MBbl/d NGL Export
- Cove Point

LT Destination

- Antero 3.2 Bcf/d Marcellus & Utica Firm Processing
- 1,400 MMcf/d
- To TCO Pool
- 389 MMcf/d
- 1,503 MMcf/d

Map:
- Gulf Coast
- Midwest Markets
- South America
- Europe
- Asia

Antero Firm Commitments

- Firm Gas Takeaway = 4.2 Bcf/d
- LNG Firm Sales = 700 MMcf/d
- Firm Processing = 3.2 Bcf/d
- Firm Ethane Takeaway and Future Sales = 77 MBbl/d
- Ethane Cracker = 30 MBbl/d
- Firm NGL C3+ Export Takeaway = 55 MBbl/d
AR’s firm transportation commitments decline by over 800 MMcf/d by year-end 2024, resulting in a ~$100 MM reduction in annualized net marketing expense (unutilized pipeline cost)

AR has already given formal notice to release 300 MMcf/d of firm transportation commitments effective during 2021 and expects to continue releasing excess capacity upon renewal dates assuming maintenance level capital spending.
AR’s firm transportation portfolio provides price stability, production flow assurance, and premium pricing vs. Appalachia-dependent producers.

**Antero Basis vs. Appalachia Basis ($/Mcf)**

- **Appalachia Differentials**
  - Green line: Appalachian Average Basis
  - Red line: Appalachia Differentials

- **Antero Realized Differential**
  - Green dotted line: Antero Realized Differential
  - Green line: Antero Average Basis

---

**Antero Basis**

- Low volatility, high reliability
- Premium to NYMEX
- “Insurance policy” for consistent production flow
- Ability to hedge liquid NYMEX Henry Hub index

**Appalachia Basis**

- High volatility, low reliability
- Significant discount to NYMEX
- Frequent shut-ins
- Less liquid hedge markets

---

**Note:** Pricing reflects pre-hedge pricing.

1) Reflects discount to NYMEX for Appalachia in-basin pricing at Dominion South & TETCO M2 indices.
2) Represents simple average discount to NYMEX for Antero firm transportation capacity. Includes BTU adjustment for 1100 BTU gas.
With uncertainty on future pipeline projects in Appalachia, Antero is one of the few natural gas producers in Appalachia that can take advantage of rising NYMEX natural gas prices without the risk of widening local basis and being forced to shut-in production.

Appalachian Takeaway Capacity is a Strategic Advantage

Potential Future Capacity

Basin Transport Capacity
Basin Dry Gas Production
Marketed Dry Gas Production Forecast
Blended Appalachian Differential to NYMEX
Appalachian Basis “Blowout”

Appalachian Differentials Likely to Widen

Expected “Call” on Appalachia Production to meet U.S. Demand

Current Basin Takeaway Capacity (33 Bcf/d)


1) Basis capacity based on pipeline flow data scrapes.
2) Production forecast and maintain Mountain Valley Pipeline (MVP) In-Service date in 2H 2021 based on Platt’s Estimate.
Corporate Presentation

- Executive Summary
- Asset Overview
- Natural Gas & NGL Macro
- Appendix
Significant Reduction in Drilling Rigs

- Since March 6th, the total U.S. rig count has declined by 441 rigs, or ~58%, and oil focused rig count has declined by 61%
  - NGL production “associated” with shale oil activity represents 68% of total U.S. NGL production and is expected to decline due to the recent collapse in oil prices and rig count.

### U.S. Oil & Gas Drilling Rig Count Since 3/6/2020

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Permian</td>
<td>429</td>
<td>180</td>
<td>(382) (61%)</td>
<td>10.7</td>
<td>1,698</td>
</tr>
<tr>
<td>Eagle Ford</td>
<td>79</td>
<td>30</td>
<td>(49) (62%)</td>
<td>5.0</td>
<td>682</td>
</tr>
<tr>
<td>Bakken</td>
<td>52</td>
<td>14</td>
<td>(38) (73%)</td>
<td>2.1</td>
<td>530</td>
</tr>
<tr>
<td>SCOOP/STACK</td>
<td>41</td>
<td>14</td>
<td>(27) (66%)</td>
<td>3.7</td>
<td>462</td>
</tr>
<tr>
<td>DJ Niobrara</td>
<td>28</td>
<td>9</td>
<td>(19) (68%)</td>
<td>2.0</td>
<td>440</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>629</td>
<td>247</td>
<td><strong>(382)</strong> (61%)</td>
<td><strong>23.6</strong></td>
<td><strong>3,811</strong></td>
</tr>
</tbody>
</table>

### Appalachia/Haynesville

| Marcellus            | 32       | 24         | (8) (25%)           | 27.4                                | 765                               |
| Haynesville          | 41       | 45         | 4                   | 12.5                                | 42                                |
| Utica                | 14       | 9          | (5) (36%)           | 6.3                                 | 142                               |
| **Total**            | 87       | 78         | **(9)** (10%)       | **46.2**                            | **949**                           |

| Other                | 50       | -          | **(50)** (100%)     | 20.4                                | 815                               |
| **Total U.S.**       | 766      | 325        | **(441)** (58%)     | 90.2                                | 5,576                             |

Rig reduction led by oil focused areas with a 382 rig, or 61% reduction since March 6th

- Down 11% from 3/6/20
- Down 8% from 3/6/20

Source: Baker Hughes and S&P Global Platts.

2) NGL production per Platts monthly average C2+ NGL estimate for November 2020 as of 11/30/2020. Assumes ~2.7 MMBbl/d of ethane, or 46% of total C2+ NGL forecast.
Significant Reduction in Completion Crews

Since March 6th, U.S. completion spread count has declined by 154 crews, or 49%, and oil focused completion crew count has declined by 53%

### U.S. Oil & Gas Drilling Completion Crew Count Since 3/6/2020

<table>
<thead>
<tr>
<th></th>
<th>Change Since 3/6/20</th>
<th>Current Dry Gas Production Bcf/d (1)</th>
<th>Current NGL Production MBbls/d (2)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>3/6/2020 12/11/2020</td>
<td>%</td>
<td></td>
</tr>
<tr>
<td><strong>Oil Focused</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Permian</td>
<td>125 73 (52) (42%)</td>
<td>10.7</td>
<td>1,698</td>
</tr>
<tr>
<td>Eagle Ford</td>
<td>44 20 (24) (55%)</td>
<td>5.0</td>
<td>682</td>
</tr>
<tr>
<td>Bakken</td>
<td>31 9 (22) (71%)</td>
<td>2.1</td>
<td>530</td>
</tr>
<tr>
<td>SCOOP/STACK</td>
<td>28 6 (22) (79%)</td>
<td>3.7</td>
<td>462</td>
</tr>
<tr>
<td>DJ Niobrara</td>
<td>19 8 (11) (56%)</td>
<td>2.0</td>
<td>440</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>247 116 (131) (53%)</td>
<td>23.6</td>
<td>3,811</td>
</tr>
<tr>
<td><strong>Appalachia/Haynesville</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Appalachia</td>
<td>26 19 (7) (27%)</td>
<td>33.7</td>
<td>907</td>
</tr>
<tr>
<td>Haynesville</td>
<td>18 14 (4) (22%)</td>
<td>12.5</td>
<td>42</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td>44 33 (11) (25%)</td>
<td>46.2</td>
<td>949</td>
</tr>
<tr>
<td><strong>Other</strong></td>
<td>26 14 (12) (46%)</td>
<td>20.4</td>
<td>815</td>
</tr>
<tr>
<td><strong>Total U.S.</strong></td>
<td>317 163 (154) (49%)</td>
<td>90.2</td>
<td>5,576</td>
</tr>
</tbody>
</table>

- **26% of U.S. dry gas production**
- **68% of U.S. NGL production**
- **Down 11% from 3/6/20**
- **51% of U.S. dry gas production**
- **17% of U.S. NGL production**
- **Down 8% from 3/6/20**

Completion spread count reduction led by oil focused areas with a 131, or 53% spread reduction since March 6th

NGL production “associated” with shale oil activity represents 68% of total U.S. NGL production and is expected to decline due to the collapse in oil prices and rig count

Source: Primary Vision and S&P Global Platts. Appalachian completion crew count based on Antero internal estimate to address discrepancies in Primary Vision data for Appalachia.

Material Impact to NGL Production in the U.S.

The drilling and completion activity decline is expected to have a pronounced negative impact on U.S. NGL supply, 68% of which comes from shale oil plays.

U.S. C2+ NGL Production Forecast (MBbl/d)

Gulf Coast LPG Export Capacity

Gulf Coast export capacity is now plentiful, which has helped clear the domestic market and has tightened Mont Belvieu LPG pricing to international pricing.

Source: Platts Analytics data as of November 30, 2020.
Domestic and international LPG prices are improving on a relative basis to crude oil, driven by resilient global demand for LPG from petrochemicals and res/com.

C3+ NGL Prices & % of WTI

Far East Index (FEI) Propane Prices & % of Brent

Source: ICEdata Mont Belvieu, Far East Index, WTI and Brent strip pricing as of 12/18/2020

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+).

2) Forecasted C3+ NGLs represent ICEdata Mont Belvieu strip pricing as of 12/18/2020. Forecasted FEI propane represents ICEdata Far East Index propane strip pricing as of 12/15/2020.
NGL Pricing Outlook

- Limited liquidity in the futures market for C3+ NGL products often does not capture anticipated value further out in the curve.
- A bottoms-up analysis of supply/demand fundamentals suggests NGL prices have significant upside to the current strip.

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+). Citi Research price deck published 10/05/2020. ICEdata Mont Belvieu strip pricing as of 12/18/2020.
Rate of growth in U.S. LPG production and export expected to soften due to the decline in drilling and completion activity in shale oil basins

Demand in Asia absorbs U.S. supply growth

Source: Poten & Partners as of November 2020.
Antero is well positioned for both the commodity price outlook and energy transition as a large, low cost natural gas and NGL producer with strong ESG metrics.

- **Scale / Operating Leverage**: 3rd Largest natural gas producer and 2nd largest NGL producer in the U.S. with exposure to strengthening commodity prices.

- **Material Cost Reduction Initiatives**: AR has targeted ~$616 MM in reductions to 2020 capital and operating expenses.

- **Asset Sale Progress**: AR has announced $751 MM of asset sales since December 2019.

- **Unsecured Financing**: Issued $288 MM of convertible senior notes and $500 MM senior notes due 2026 to refinance a portion of near-term maturities.

- **Free Cash Flow Profile**: Expect to generate $175 - $200 MM (1) of 2H2020 Free Cash Flow at current strip prices.

- **Robust Liquidity**: Pro forma YE 2020 estimated liquidity of $1.2 (2) B to address the 2022 bond maturities.

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1) Free Cash Flow is a non-GAAP term. See appendix for more information, including certain material assumptions in projecting Free Cash Flow.

2) Pro forma for $175 - $200 MM 2H2020 forecast Free Cash Flow. Includes $313 MM redemption of 2021 notes and $102 million of contingent payments, $51 million of which was earned based on volume thresholds met during the third quarter of 2020. The remainder may be earned based on achieving volume thresholds through the first quarter of 2021. Includes net proceeds from the December 2020 senior notes offering and the redemption of $350 MM of senior notes due 2022.
Antero Resources Executive Summary

Asset Overview

Natural Gas & NGL Macro

Appendix
Strategic Updates in 2020

**Senior Notes Offering (Expected to close 01/04/2021)**
- $500 MM senior notes offering due 2026
  - Coupon rate of 8.375%
  - Demonstrates access to unsecured debt financing

**Convertible Note Issuance (8/18/2020)**
- $288 MM convertible senior note issuance due 2026
  - Coupon rate of 4.25% with $4.34 per share strike price

**Closed VPP Transaction (8/11/2020)**
- $220 MM VPP sale to an affiliate of J.P. Morgan
  - Net production of 60 MMcf/d for second half of 2020, 75 MMcf/d in 2021 then declines to 40 MMcf/d by the first half of 2027
  - Transaction value based on pricing of NYMEX Henry Hub, less $0.60/MMBtu (transport costs and basis differentials)
  - Attractive mid-single digit cost of capital for PDP asset

**Announced Cash Tender Offer for 2021, 2022 & 2023 Notes (8/24/2020)**
- $367 MM of senior notes purchases:
  - Purchased $183 MM of 2021 senior notes at a 2% discount price of $98
  - Through modified Dutch tender offer purchased $88 MM of the 2022 senior notes at a 14% discount price of $86 and $96 MM of the 2023 senior notes at a 22% discount price of $78

**Closed ORRI Transaction With Sixth Street Partners (6/12/2020)**
- Overriding royalty interest (ORRI) transaction with Sixth Street for proceeds of $402 MM
- $300 MM cash received at closing plus up to $102 MM of future payments over the next twelve months
  - $102 MM consists of two contingent payments of up to $51 MM each based on volume thresholds relating to expected cumulative production net to the ORRI through 9/30/2020 and 3/31/2021, respectively
  - Monetized $29 MM of gas hedges in July 2020 to align hedges with 2021 projected net volumes adjusted for ORRI

**Debt Repurchases and Borrowing Base (4Q 2019 through 4Q 2020)**
- Have repurchased $2.0 B of senior notes including open market purchases, debt tender offer and 2021-2022 senior note redemptions - absolute debt reduction of ~$220 MM (17% discount) and annualized interest expense reduction of $41 MM
- Antero’s $2.85 B borrowing base remains unchanged following the ORRI and VPP transactions
• **Significant Reduction in Well Costs already “in-hand”**

  - Reduced well costs by ~30% ($3.5 million per well)

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**Marcellus Well Cost Reductions (January 2019 AFE to Current 2020)**

Note: Well costs include ~$1 MM or ~$80/ft for facilities, pads and road costs per well assuming a 12,000’ lateral.
• **Materially Reducing LOE**
  – Reducing LOE by 45% in 2020 (~$90 MM+)

**Antero Lease Operating Expense Reductions (2020 Target)**

- **2020E LOE Pre-Water Savings Initiatives**
  - $194.0
  - $0.15/Mcfe

- **Existing Wells Produced Water (after 90 days, 70% of total)**
  - $42.0
  - $42 MM ($0.03/Mcfe) reduction driven by $6/Bbl savings related to wells already on sales

- **New 2020 Completions Produced Water (after 90 days, 30% of total)**
  - $32.0
  - $32 MM ($0.03/Mcfe) reduction driven by $6/Bbl savings related to new wells in 2020

- **Continued Water Initiative + Efficiencies**
  - $16.0
  - $16 MM ($0.01/Mcfe) reduction driven by trucking performance, service cost deflation and efficiencies

- **2020E LOE Target**
  - $104.0
  - $0.08/Mcfe

45% Reduction ($90 MM+)
The U.S. currently has ~37 days of supply, or 12% below the 5-year average.

Source: EnVantage Inc. and Energy Information Administration (EIA) as of 11/30/20.
LPG export arbs have widened to their highest levels since Antero began exporting in early 2019, providing strong realized NGL pricing for Antero.

Source: Bloomberg actuals for pricing through 12/18/2020.
NGLs play an essential role in the domestic and international industrial, residential, commercial and transportation industries.

<table>
<thead>
<tr>
<th>Primary Sectors</th>
<th>Methane</th>
<th>Ethane</th>
<th>Propane</th>
<th>Butane</th>
<th>Iso-Butane</th>
<th>Pentane</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas</td>
<td>C2</td>
<td>C3</td>
<td>C4</td>
<td>IC4</td>
<td>C5</td>
<td></td>
</tr>
<tr>
<td>All</td>
<td>Chemical Industrial</td>
<td>Industrial Residential Commercial, Chemical</td>
<td>Industrial Transportation</td>
<td>Industrial</td>
<td>Transportation</td>
<td></td>
</tr>
<tr>
<td>Power</td>
<td>Ethylene Production (For plastics)</td>
<td>Heating, Crop drying, Commercial, Propylene</td>
<td>Winter Gasoline Blending</td>
<td>Alkylate feed to produce gasoline</td>
<td>Gasoline blend and diluent</td>
<td></td>
</tr>
</tbody>
</table>

Higher Heating Value

1000 BTU

4000 BTU
Antero intends to “net share settle” the convertible notes but will have the option upon conversion to settle in cash, shares, or any combination:

- Non-callable for 3.5 years
- Callable on or after 3/1/24 if stock price exceeds 130% of conversion price for a specified period of time

Antero repurchased ~37 MM shares since 4Q19 at an average price of $1.75

### Net Share Settle Illustration

**Conversion example at $6.00/share**
- Conversion value = $6.00 x 66.3 MM = $398 MM
- Settled in cash = $288 MM
- In shares = $110 MM ÷ $6.00 per share = **18.3 MM shares or 6.8% dilution**

<table>
<thead>
<tr>
<th>Stock appreciation from $3.62</th>
<th>0%</th>
<th>38%</th>
<th>66%</th>
<th>93%</th>
<th>121%</th>
<th>149%</th>
<th>176%</th>
<th>204%</th>
<th>232%</th>
<th>259%</th>
</tr>
</thead>
<tbody>
<tr>
<td>AR Share Price Assumption at Conversion ($/Share)</td>
<td>$3.62</td>
<td>$5.00</td>
<td>$6.00</td>
<td>$7.00</td>
<td>$8.00</td>
<td>$9.00</td>
<td>$10.00</td>
<td>$11.00</td>
<td>$12.00</td>
<td>$13.00</td>
</tr>
<tr>
<td>Settled in Shares ($MM)</td>
<td>$0</td>
<td>$110 MM</td>
<td>$176 MM</td>
<td>$242 MM</td>
<td>$309 MM</td>
<td>$375 MM</td>
<td>$441 MM</td>
<td>$508 MM</td>
<td>$574 MM</td>
<td>$663</td>
</tr>
<tr>
<td>Number of Shares</td>
<td>18 MM</td>
<td>25 MM</td>
<td>30 MM</td>
<td>34 MM</td>
<td>38 MM</td>
<td>40 MM</td>
<td>42 MM</td>
<td>44 MM</td>
<td>44 MM</td>
<td>66.3 MM</td>
</tr>
</tbody>
</table>

Note: $3.62 share price reflects closing price on date of issuance. Based on pre-conversion shares outstanding of 268 MM. Chart assumes conversion at maturity. The impact of a “make-whole fundamental change” is not incorporated in the chart above.
**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, contract termination and rig stacking costs, simplification transaction fees, and gain or loss on sale of assets. Adjusted EBITDAX also includes distributions received with respect to limited partner interests in Antero Midstream Partners 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 natural gas industry to measure operating performance without regard to items excluded from the calculation of such term, which may vary substantially from company to company depending upon accounting methods and the 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 and legal structure from its consolidated 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 effects of certain recurring and non-recurring items that materially affect the Company’s net income or loss, 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.

**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.

**Leverage:** Leverage is calculated as LTM Adjusted EBITDAX divided by net debt.

**F&D Cost:** Net F&D costs 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. Net F&D costs 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 Net F&D costs, and therefore a reconciliation to GAAP is not practicable.

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

Free Cash Flow:

Free Cash Flow is a measure of financial performance not calculated under GAAP and should not be considered in isolation or as a substitute for cash flow from operating, investing, or financing activities, as an indicator of cash flow, or as a measure of liquidity. The Company defines Free Cash Flow as Net Cash Provided by Operating Activities, less drilling and completion capital and leasehold capital plus earnout payments.

The Company has not provided projected Net Cash Provided by Operating Activities or a reconciliation of Free Cash Flow to projected Net Cash Provided by Operating Activities, the most comparable financial measure calculated in accordance with GAAP. The Company is unable to project Net Cash Provided by Operating Activities for any future period because this metric includes the impact of changes in operating assets and liabilities related to the timing of cash receipts and disbursements that may not relate to the period in which the operating activities occurred. The Company is unable to project these timing differences with any reasonable degree of accuracy without unreasonable efforts. Targeted 2020 Free Cash Flow is based on current strip pricing.

Free Cash Flow is a useful indicator of the Company’s ability to internally fund its activities and to service or incur additional debt. There are significant limitations to using Free Cash Flow 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 Free Cash Flow reported by different companies. Free Cash Flow does 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.