Company Presentation

MAY 2018

Cautionary Statement

This presentation includes "forward-looking statements". Such forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond AR's control. All statements, except for statements of historical fact, made in this release regarding activities, events or developments AR expects, believes or anticipates will or may occur in the future, such as those regarding future commodity prices, future production targets, completion of natural gas or natural gas liquids transportation projects, future earnings, Consolidated Adjusted EBITDAX, Stand-Alone E&P Adjusted EBITDAX, Consolidated Adjusted Operating Cash Flow, Stand-Alone Adjusted Operating Cash Flow, Free Cash Flow, 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, future financial position, future technical improvements and future marketing opportunities, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. All forward-looking statements speak only as of the date of this release. Although Antero believes that the plans, intentions and expectations reflected in or suggested by the forward-looking statements are reasonable, there is no assurance that these plans, intentions or expectations will be achieved. Therefore, actual outcomes and results could materially differ from what is expressed, implied or forecast in such statements.

AR cautions you that these forward-looking statements are subject to all of the risks and uncertainties, most of which are difficult to predict and many of which are beyond the AR's control, incident to the exploration for and development, production, gathering and sale of natural gas, NGLs and oil. These risks include, but are not limited to, commodity price volatility, inflation, lack of availability of drilling and production equipment and services, environmental risks, drilling and other operating risks, regulatory changes, the uncertainty inherent in estimating natural gas and oil reserves and in projecting future rates of production, cash flow and access to capital, the timing of development expenditures, and the other risks described under the heading "Item 1A. Risk Factors" in AR's Annual Report on Form 10-K for the year ended December 31, 2017.

Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

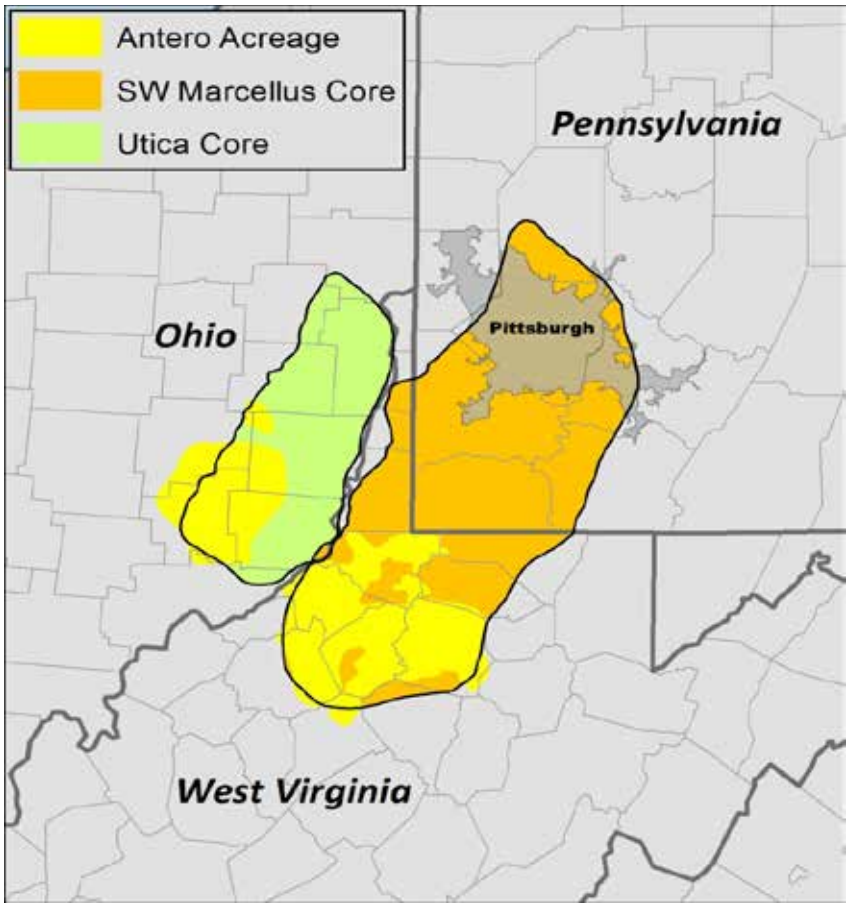
This presentation includes certain financial measures that are not calculated in accordance with U.S. generally accepted accounting principles ("GAAP"). These measures include (i) Consolidated Adjusted EBITDAX, (ii) Stand-Alone E&P Adjusted EBITDAX, (iii) Consolidated Adjusted Operating Cash Flow, (iv) Stand-Alone E&P Adjusted Operating Cash Flow, (v) Free Cash Flow. 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, Antero Midstream Partners LP is denoted as "AM" and Antero Midstream GP LP is denoted as "AMGP", which are their respective New York Stock Exchange ticker symbols.

The Size and Scale to Capitalize on the Resource

Antero Resources Profile

Market Cap……..	$6.0B
Enterprise Value…….	$9.6B
Corporate Debt Ratings…….	Ba2 / BB+ / BBB-
Stand-Alone Leverage……..	2.5x
Net Production (2018E)….....	2.7 Bcfe/d
Liquids.....	130,000 Bbl/d
3P Reserves……....	54.6 Tcfe
Net Acres……..…….	620,000
Core Drilling Locations…….	3,295
Hedge Mark to Market……..	$1.2B
AR Midstream Ownership (53%)	$2.7B

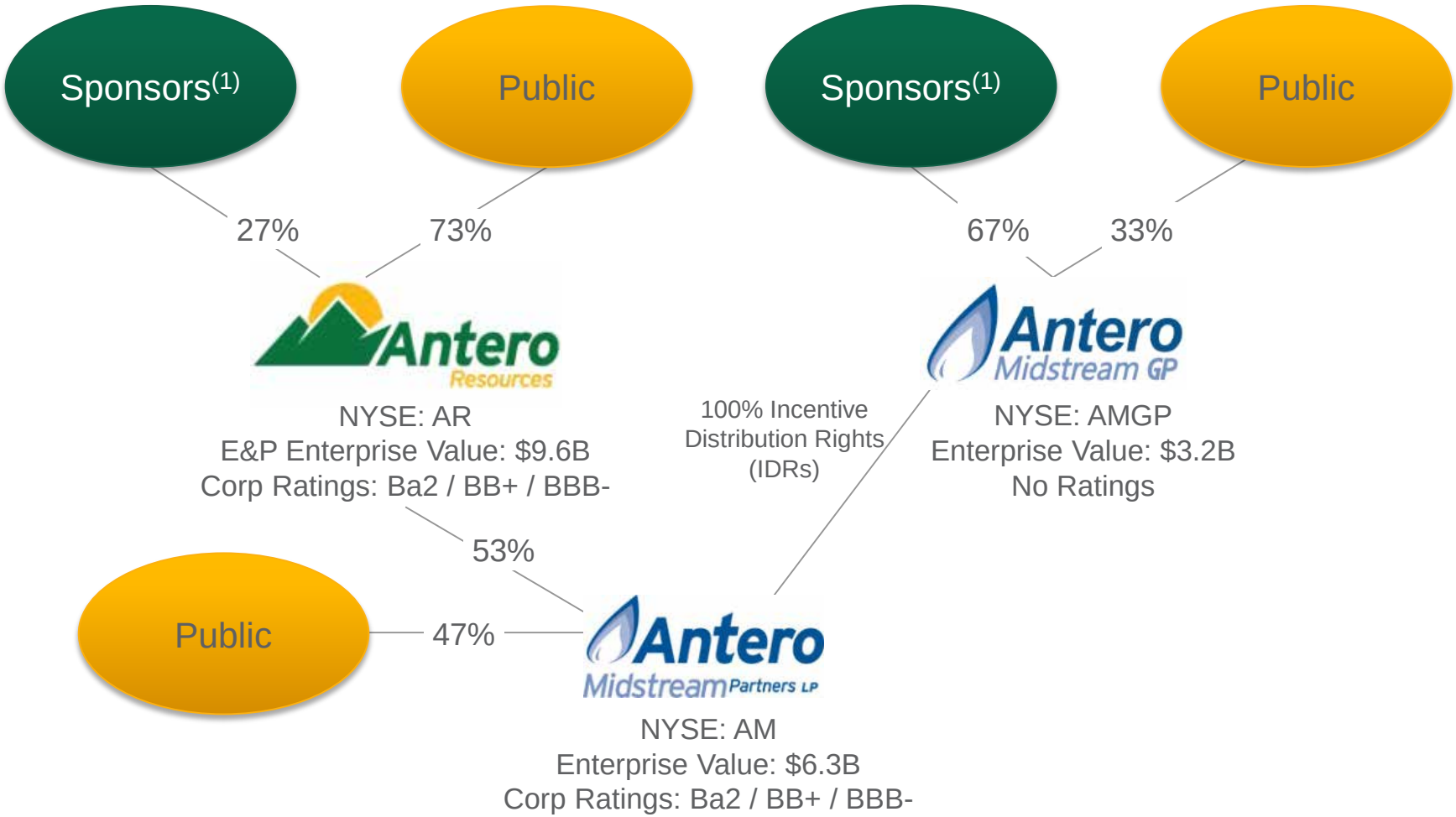


AR LISTED NYSE

Note: Equity market data as of 4/30/18. Balance sheet data, hedge mark to market, and reserves as of 3/31/18. Enterprise value excludes AM net debt. See 2018 Guidance in Appendix.

Organizational Structure

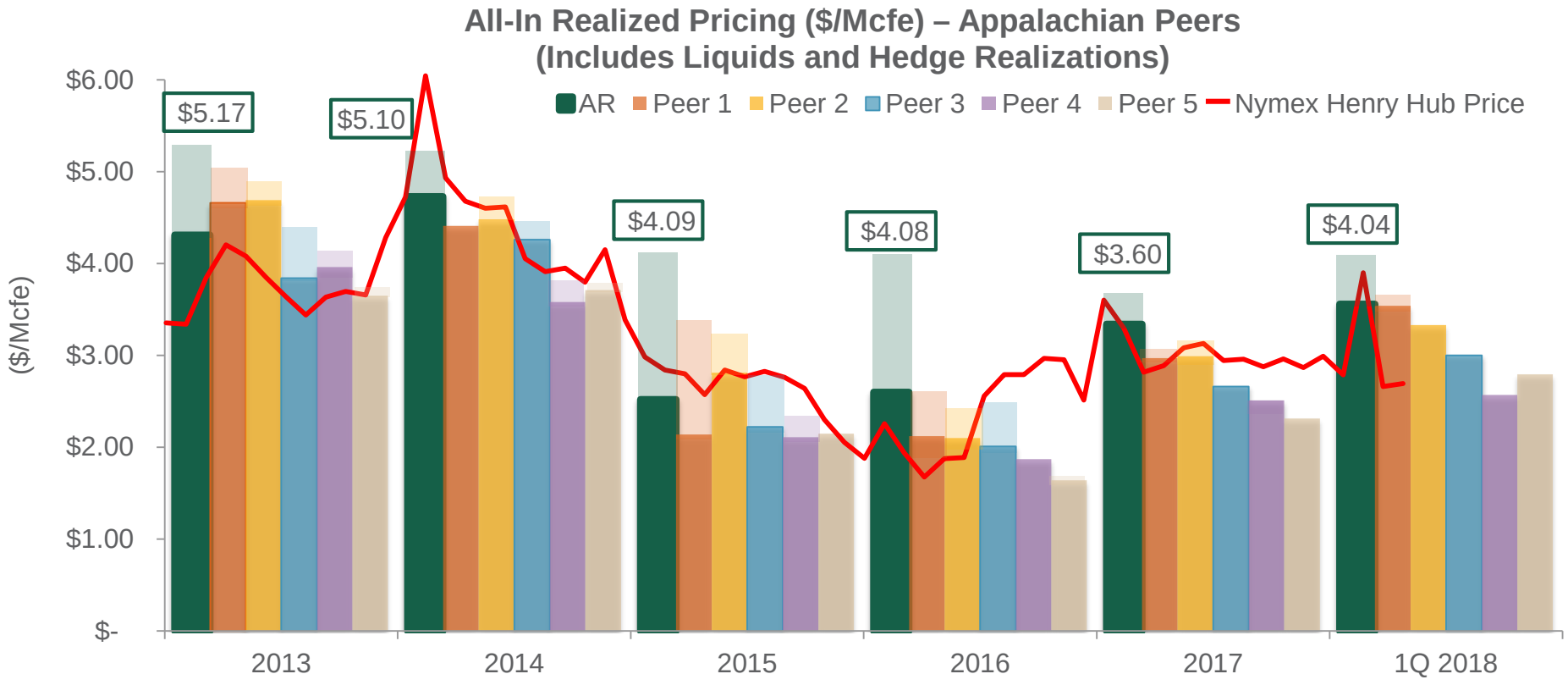
A $17B Integrated Natural Gas and NGL Business



Note: Enterprise value as of 4/30/18. AR E&P enterprise value excludes $2.7 Bn of ownership value in AM and AM net debt.
(1) Sponsors represent Warburg Pincus, Yorktown & senior management.

The Leader in All-In Realized Pricing in Appalachia…

Integrated strategy including the most effective firm transportation portfolio, NGL production growth, midstream build out and hedging resulted in the highest all-in realized prices amongst the peer group

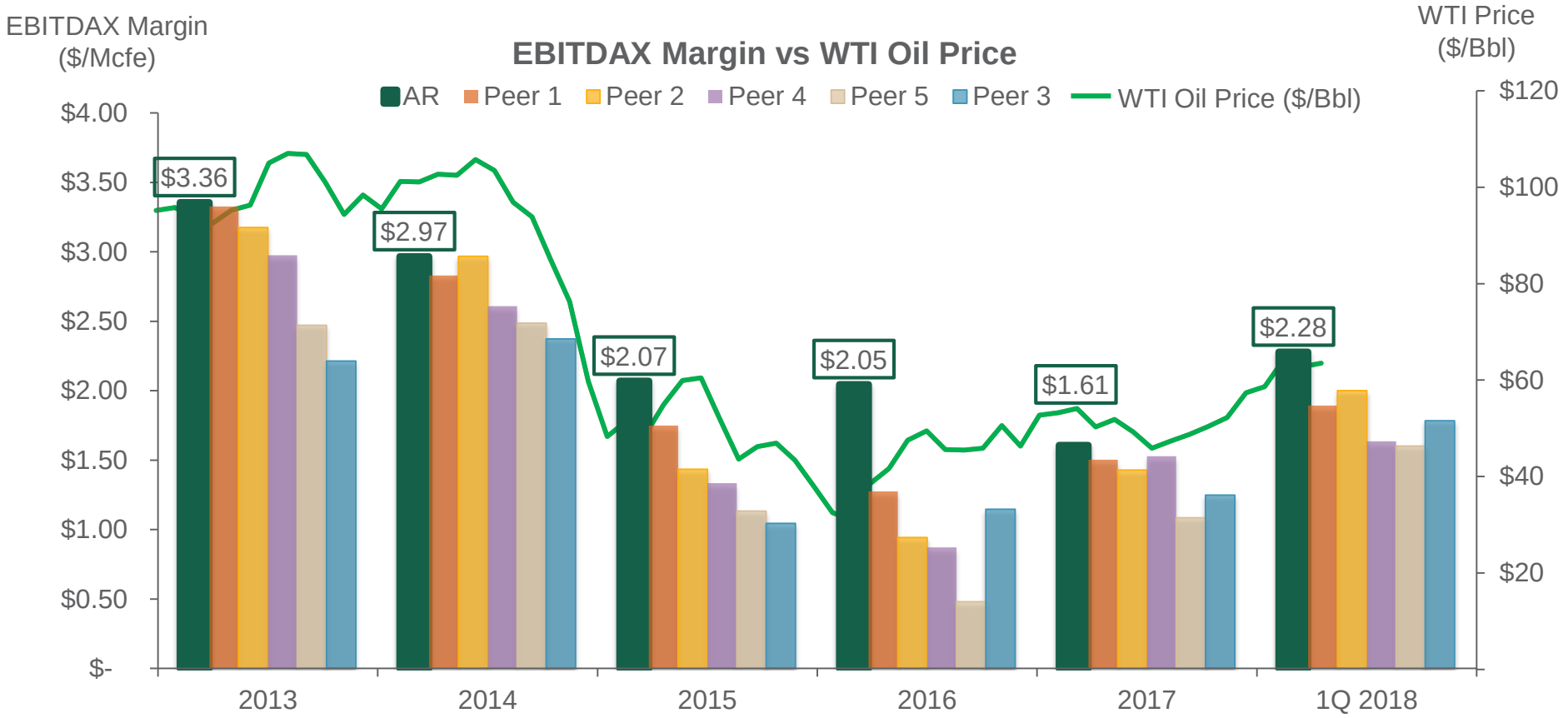


Antero Has Been the Leader in Natural Gas Equivalent Prices For Over Five Years

Source: Public data from company 10-Ks. Peers include CNX, COG, EQT, RRC and SWN. All-in realized natural gas equivalent pricing includes liquids and hedge realizations for the period. Hedge realizations is the stippled top portion of each bar.

…More Importantly, The Leader in EBITDAX Margin Too

Antero's integrated strategy has generated the highest EBITDAX margins in its peer group for over five years



On a Stand-Alone EBITDAX Margin Basis, Antero has Consistently Outperformed its Appalachian Peers Through Up and Down Commodity Cycles

Source: SEC filings and company press releases. AR 2017 margins exclude $0.10/Mcfe negative impact from WGL and SJR natural gas contract disputes. Peers include CNX, COG, EQT, RRC & SWN.
(1) AR and EQT EBITDAX include distributions from midstream ownership. Cash costs for AR and EQT represent stand-alone GPT, production taxes, LOE and cash G&A. Post-hedge and post net marketing expense where applicable.

A Cash Flow Inflection Point

- Announced New Long Lateral Development Plan Averaging 11,500' per Well
- Step Change in Capital Efficiency Reduces 5-Year D&C Capex by $2.9B
- Highest Leverage to NGL Prices Among Top NGL Producers
- The Size & Scale to Capitalize on Resource

Sustainable Cash Flow Growth

Generating 5-Year Free Cash Flow of $1.6B at YE Strip & $2.8B at $60 Oil

Disciplined Returns Focus

→ 28% Full Cycle Returns
→ 23% 5-Year Debt-Adjusted Production CAGR per share
→ 22% 5-Year Cash Flow CAGR per share

Joining an Elite E&P Group With:

- **Scale**
- **Double Digit Growth**
- **Low Leverage**
- **Free Cash Flow**

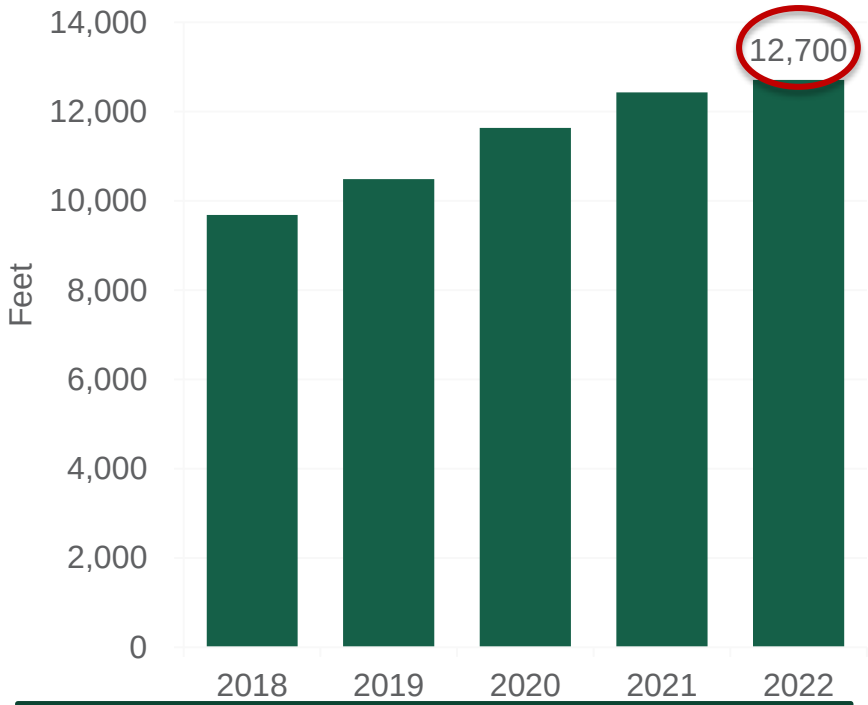
Note: See definitions for free cash flow and assumptions behind long-term targets in Appendix; free cash flow definition includes maintenance land spending, but excludes discretionary land spending.

New Long Lateral Development Plan

5-Year Plan Averages 11,500’

59% of Inventory Now ≥ 10,000’ Lateral Length

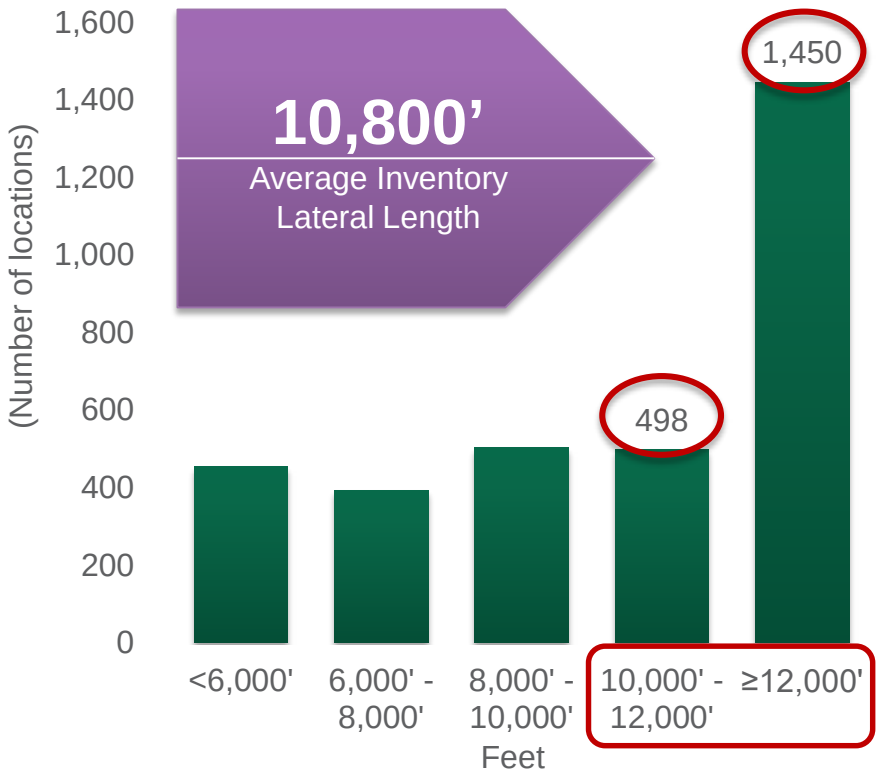
Average Lateral Length per Completed Well



	2018	2019	2020	2021	2022
Wells Completed(1)	145	155	160	165	165

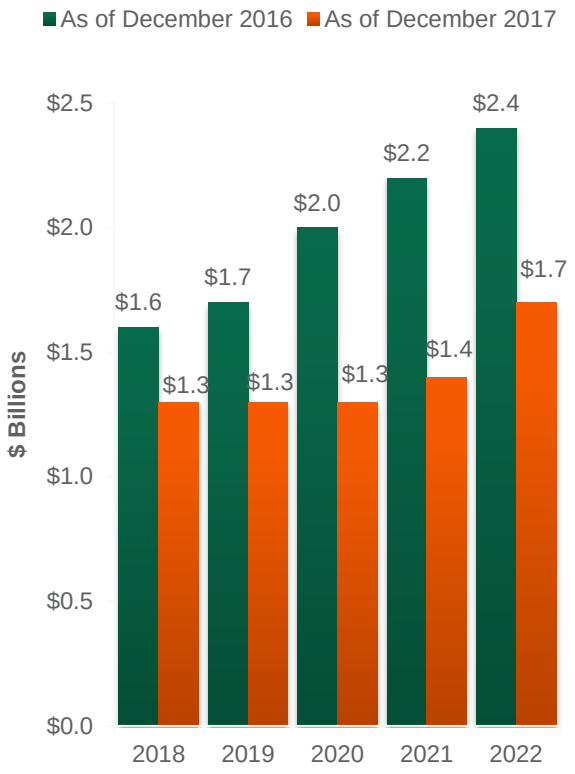
1) *Wells completed reflects midpoint of targeted completions per year.*

Core Drilling Inventory by Lateral Length



Step Change in Capital Efficiency

Consolidated Drilling & Completion Capital Expenditures



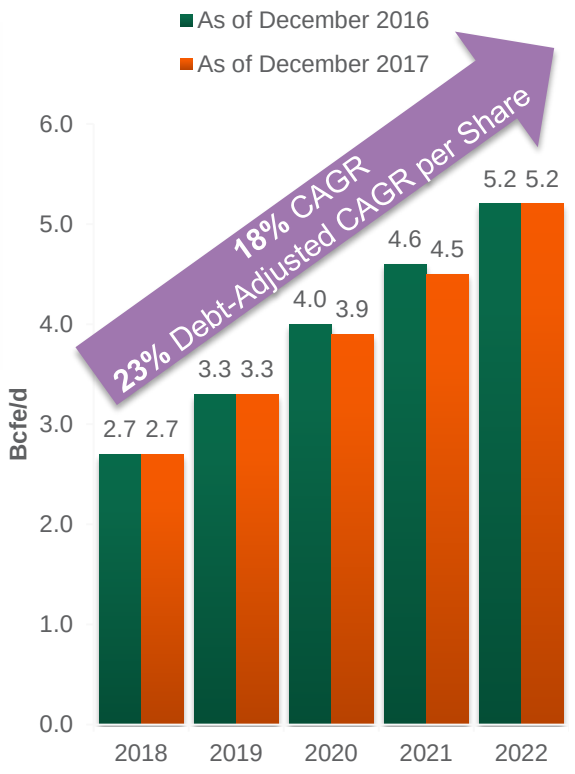
$2.9B Capex Reduction Over 5 Years

Cumulative Reduction in Drilling & Completion Capital

Same Production Targets

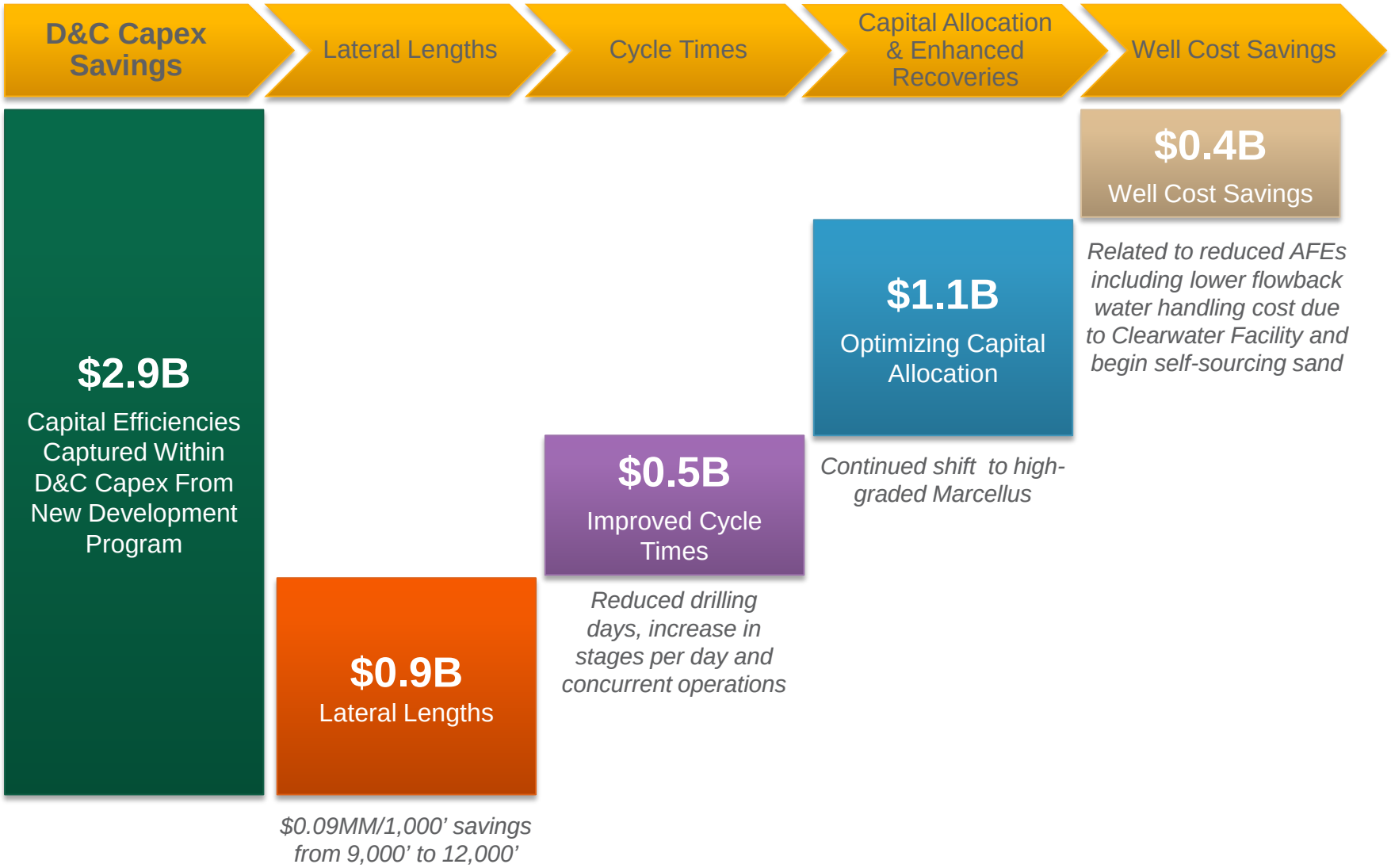
20% Production CAGR 2018-2020
15% Production CAGR 2021-2022

Production Targets



Same Production Growth With Much Less Capital Spending

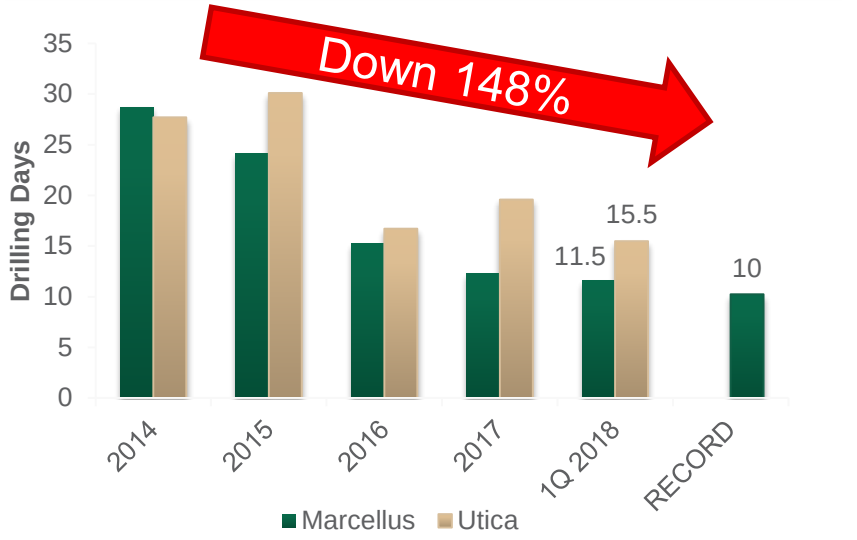
Breakdown of D&C Capex Savings



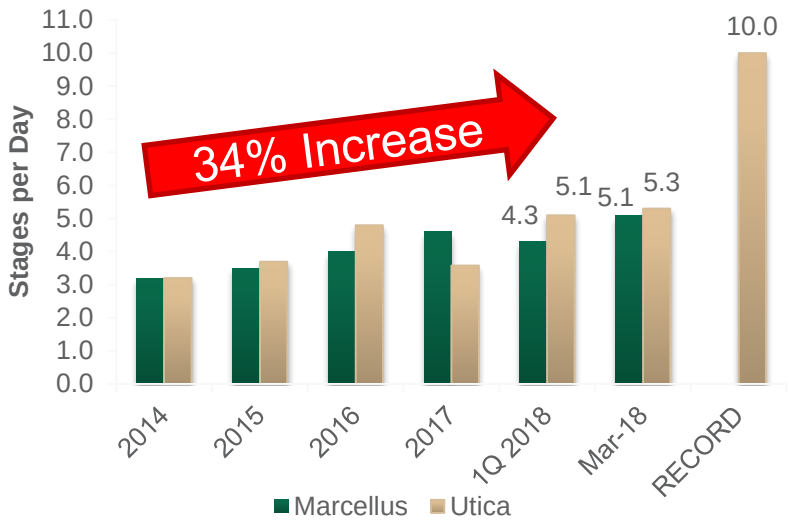
Note: See appendix for further detail on D&C capital.

Drilling and Completion Efficiencies

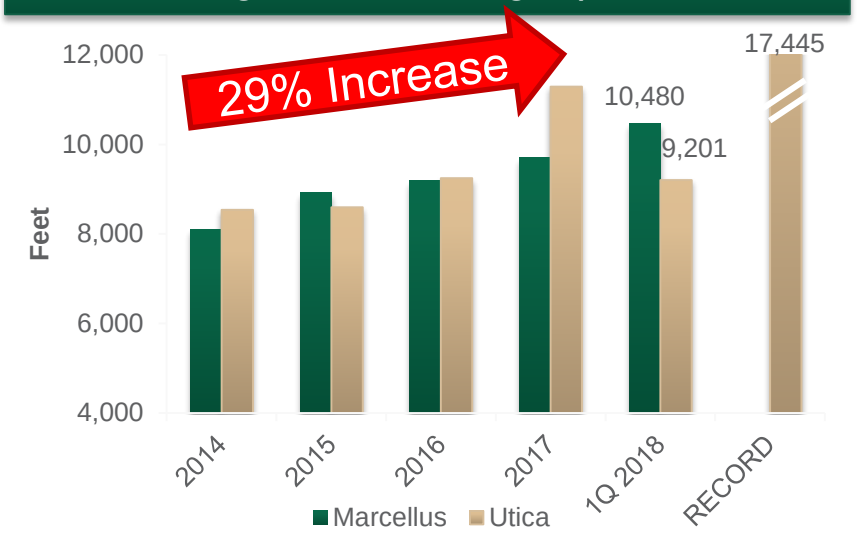
Drilling Days



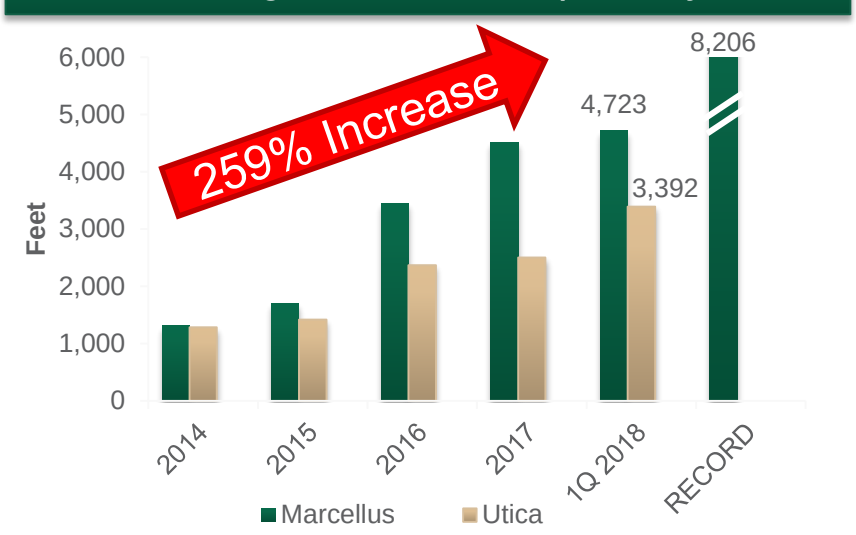
Completion Stages per Day



Average Lateral Length per Well



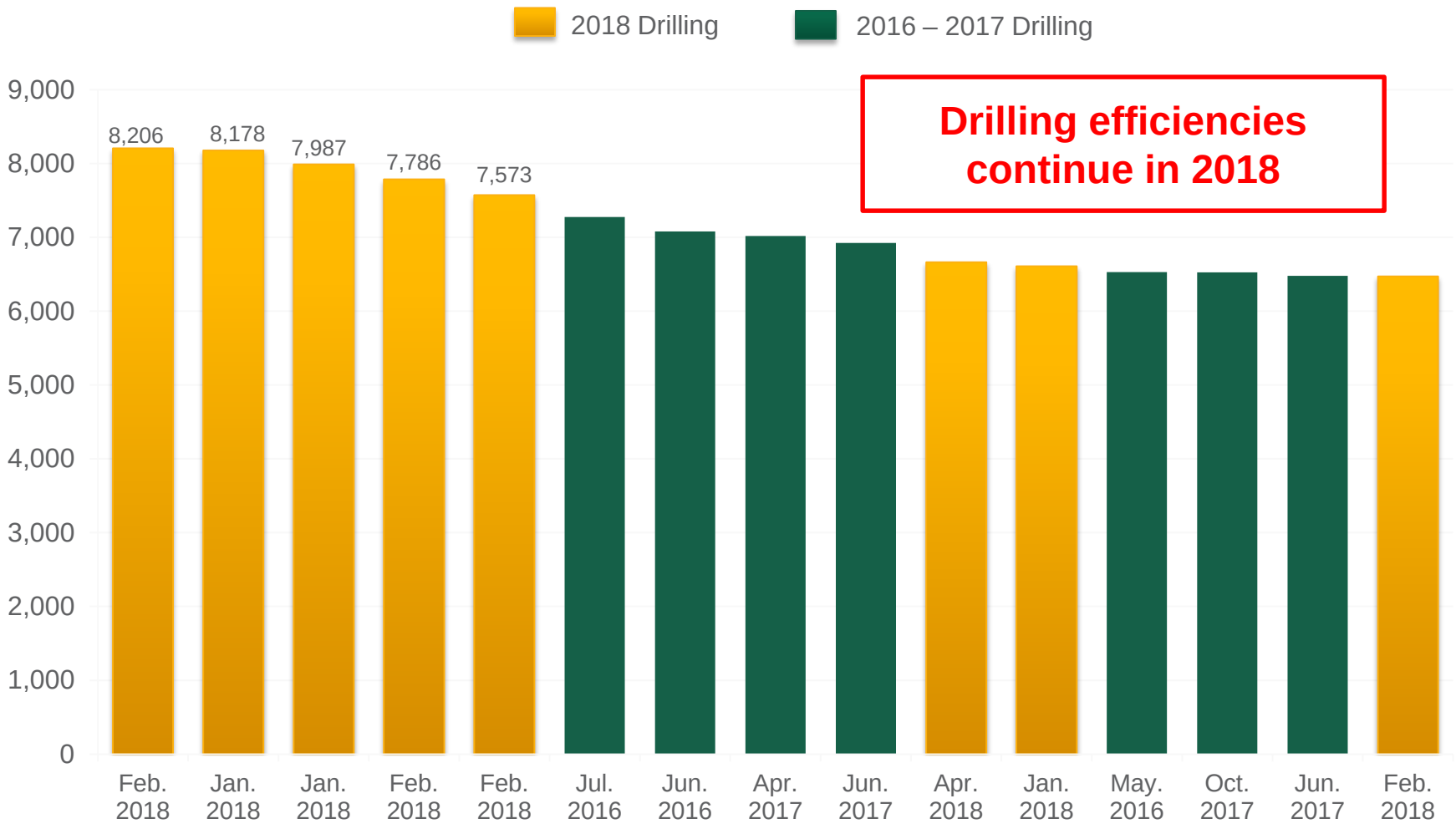
Average Lateral Feet per Day



Note: Percentage increase and decrease arrows represent change in Marcellus data from 2014 to 1Q 2018.

Drilling Best Lateral Footage in 2018

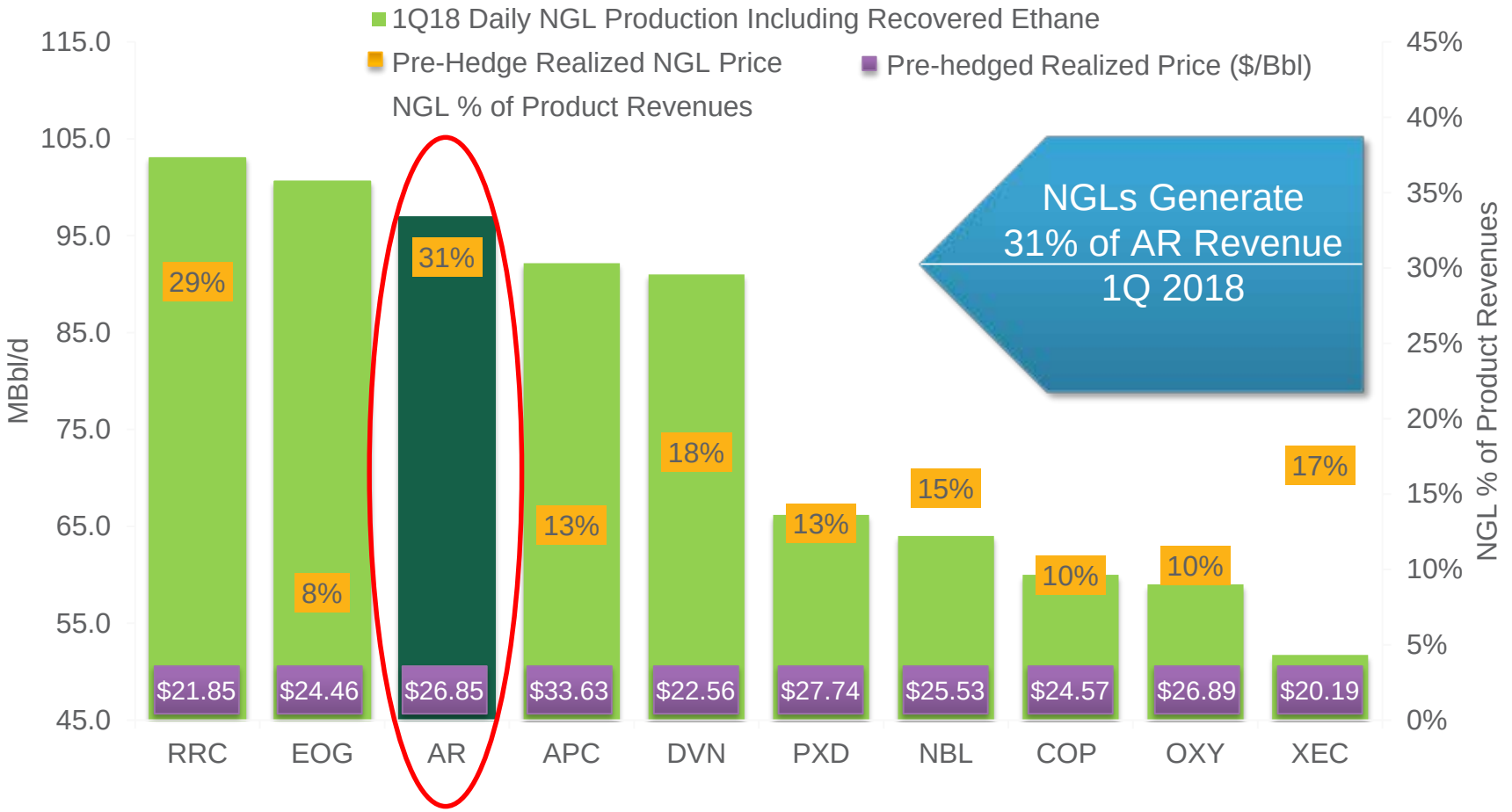
Antero Top 15 Marcellus Lateral Footage Days (24 Hour Period)



8 out of Antero's Top 15 Marcellus Lateral Footage Days Have Occurred in 2018

Highest Leverage to NGL Prices Among Top Producers

Top NGL Producers in the U.S.



Antero Has The Highest NGL Price Exposure Among Top NGL Producers

Source: SEC filings and company press releases.
Note: Realized prices are weighted average including ethane (C2) where applicable. Percent of total product revenues is calculated on a pre-hedge basis.

Outstanding Corporate Level Well Economics

Well Economics Support Investment

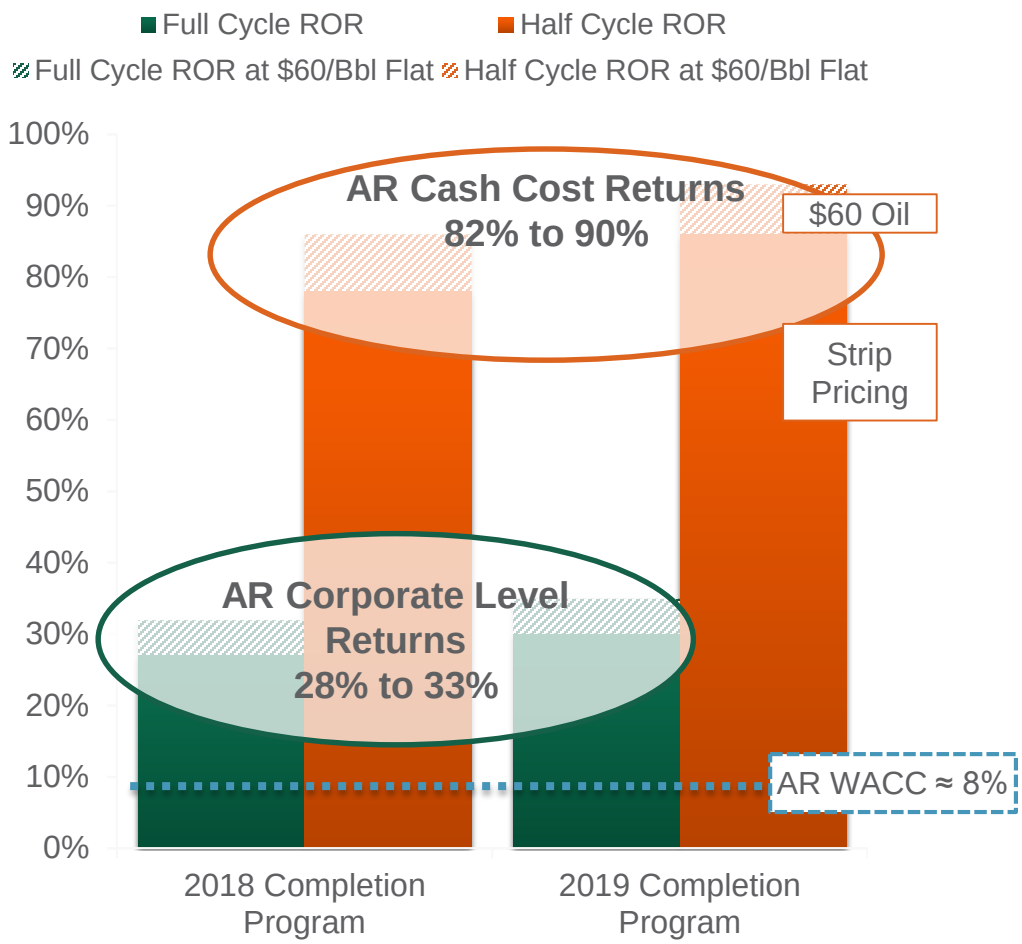
ROR Well in Excess of Cost of Capital

28% Corporate Level ROR

2018 & 2019 Full Cycle Returns

Assumes YE 2017 Strip & Excludes Hedging Impact

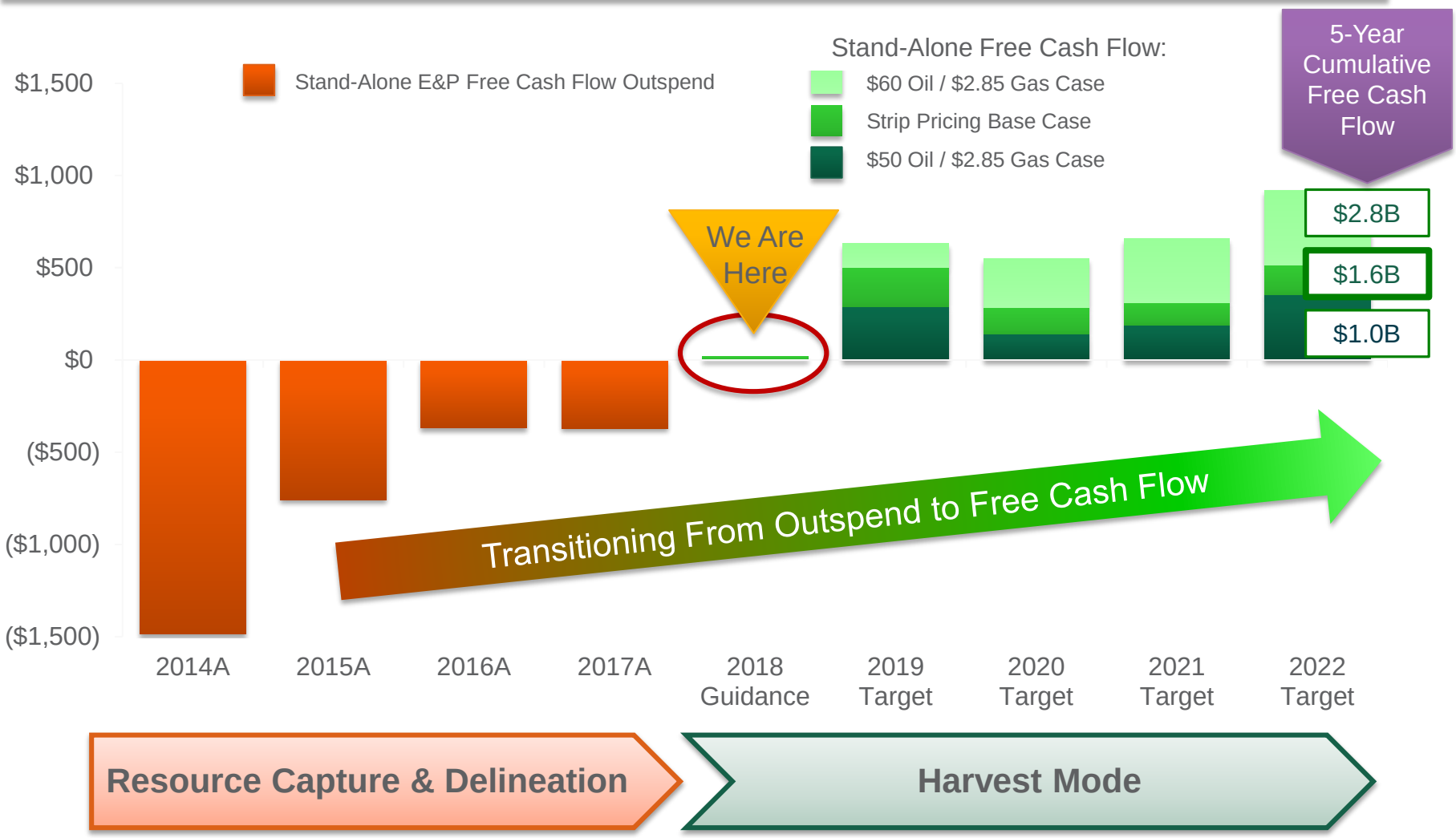
Single Well Economics – Excluding Hedges



Note: Half cycle burdened with 60% of AM fees to give credit for AM ownership/distributions and firm transportation variable fees. Full cycle burdened with G&A, land costs, 100% of AM fees and full FT costs. See Appendix for detailed assumptions for full cycle and half cycle single well economics; WACC calculated using CAPM.

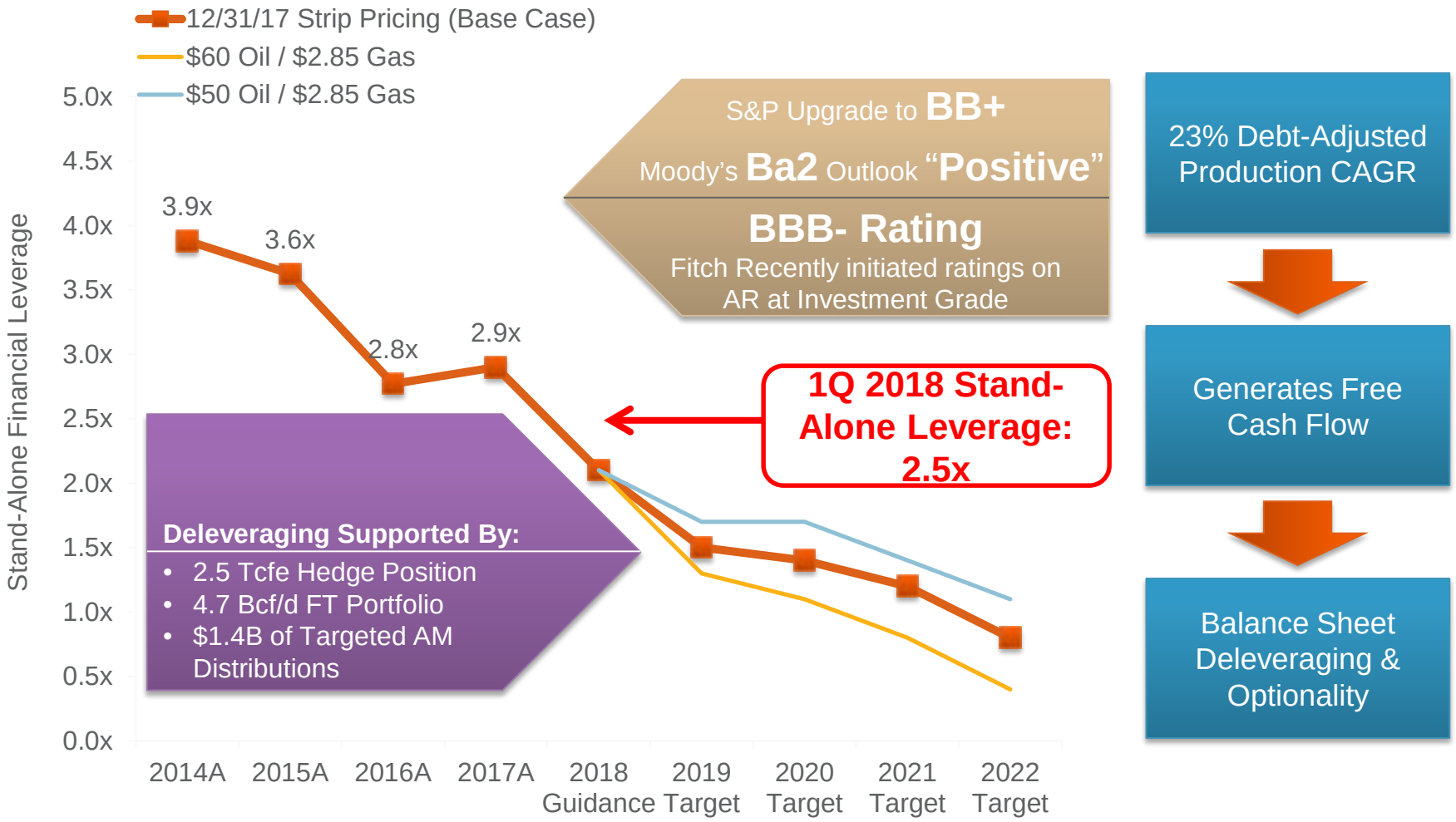
Lower Capital & Higher Liquids → Free Cash Flow

D&C Capital Investment Fully Funded with Cash Flow
→ $1.6B of Targeted Free Cash Flow Over the Next 5 Years



Note: See definitions for free cash flow and assumptions behind long-term targets in Appendix; free cash flow definition includes $200MM maintenance land spending, but excludes $300MM discretionary land spending.

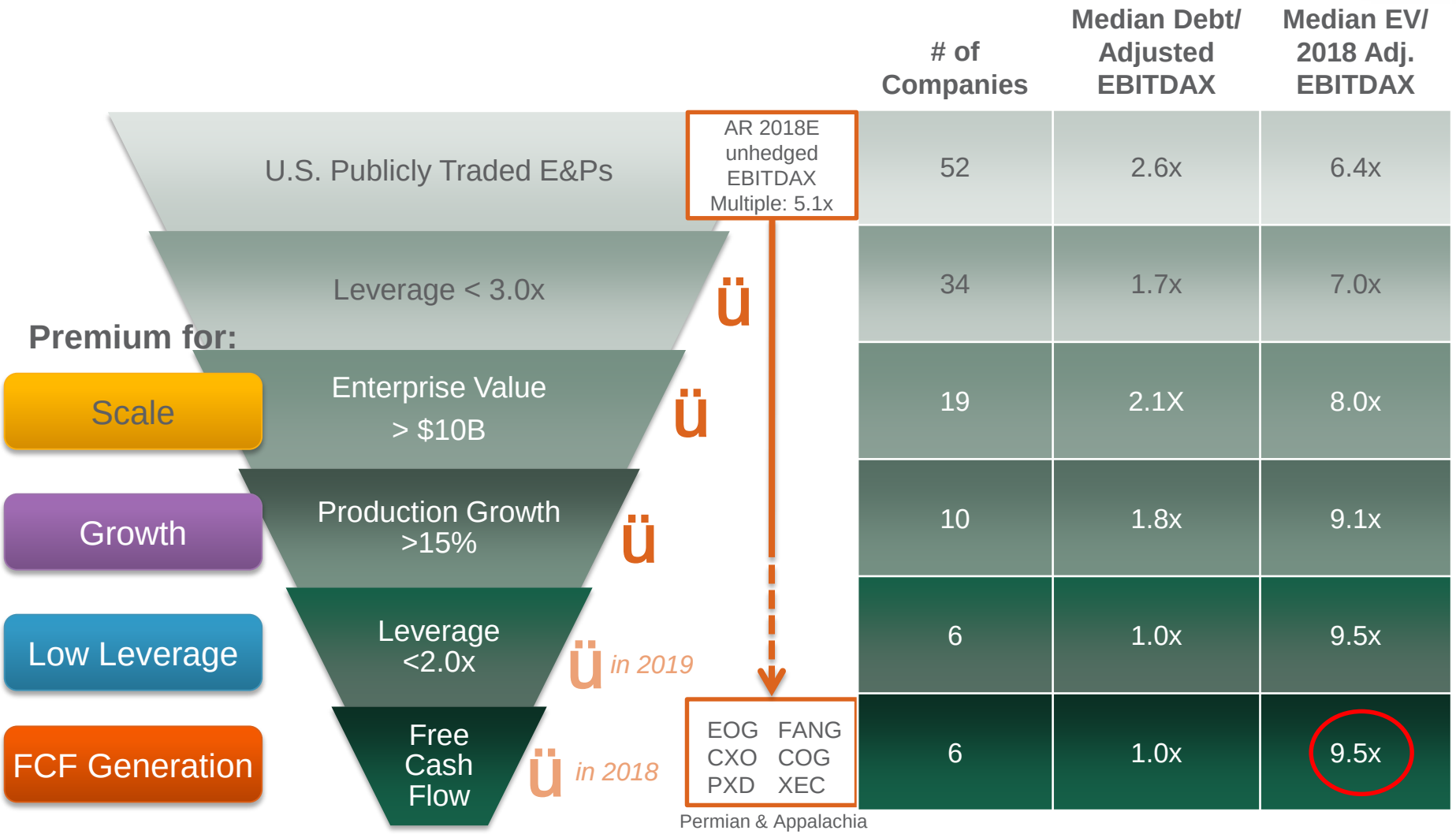
Cash Flow Growth → Deleveraging Profile



Leverage targets inclusive of $500 MM of maintenance and discretionary land capex from 2018 - 2022

Note: See Appendix for key definitions and assumptions. Stand-alone financial leverage is calculated by dividing year-end stand-alone debt by last twelve months stand-alone EBITDAX. Note all free cash flow after land spending is assumed to be used for debt reduction.

Antero Profile Should Drive Multiple Expansion



	# of Companies	Median Debt/ Adjusted EBITDAX	Median EV/ 2018 Adj. EBITDAX
U.S. Publicly Traded E&Ps	52	2.6x	6.4x
Leverage < 3.0x	34	1.7x	7.0x
Enterprise Value > $10B	19	2.1X	8.0x
Production Growth >15%	10	1.8x	9.1x
Leverage <2.0x	6	1.0x	9.5x
Free Cash Flow	6	1.0x	9.5x

Joining an Elite Group of E&Ps With Scale, Double Digit Growth, Low Leverage & Free Cash Flow Generation

Source: Bloomberg & Antero Estimates as of 4/30/18.

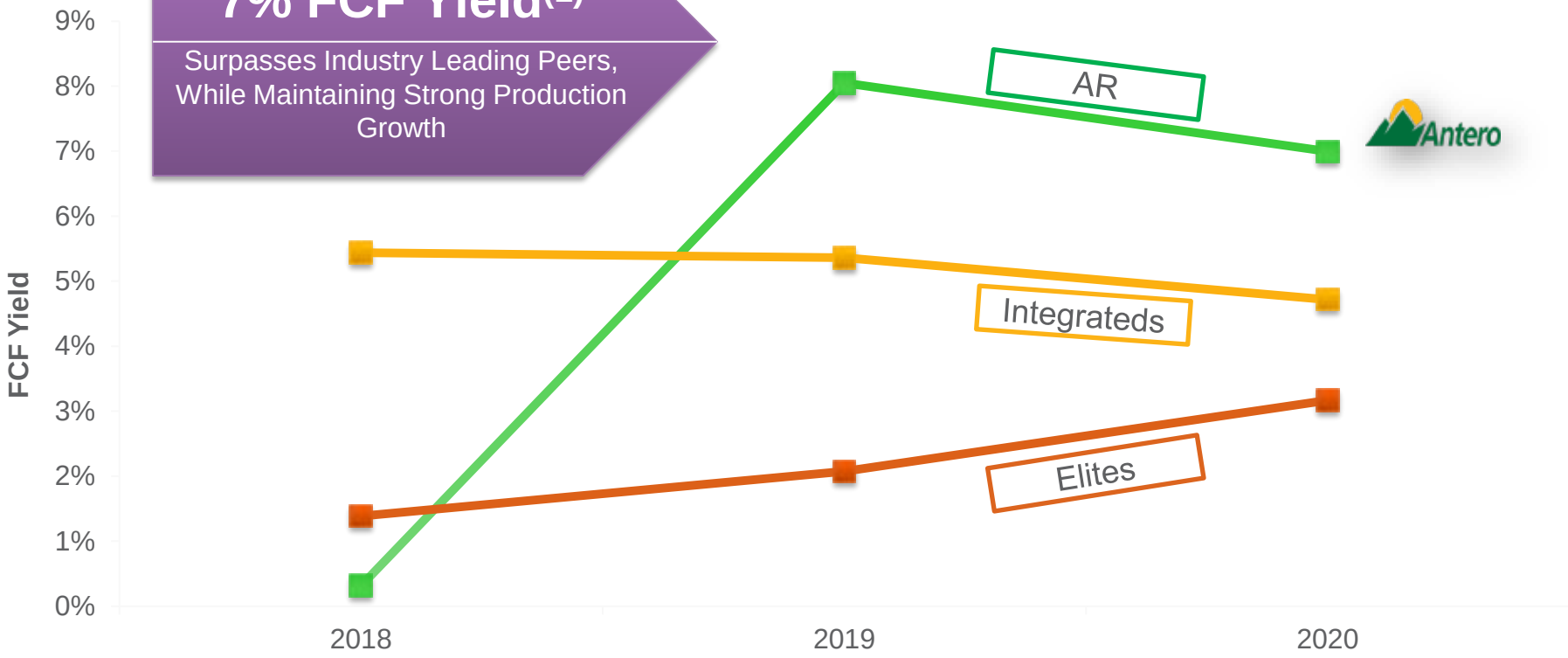
(1) Adjusted EBITDAX and Adjusted Operating Cash Flow are non-GAAP measures. AR EV/EBITDAX multiple also reflects an enterprise value that excludes AR ownership of AM, and EBITDAX excludes AM distributions received by AR, for comparative purposes with peer E&P multiples. For additional information regarding these measures, please see "Antero Definitions" and "Antero Non-GAAP Measures" in the Appendix.

Attractive Free Cash Flow Yield

Assuming current stock prices, Antero should deliver free cash flow yield well in excess of both the integrateds and the "best in class" E&P peers

AR
7% FCF Yield(1)

Surpasses Industry Leading Peers, While Maintaining Strong Production Growth

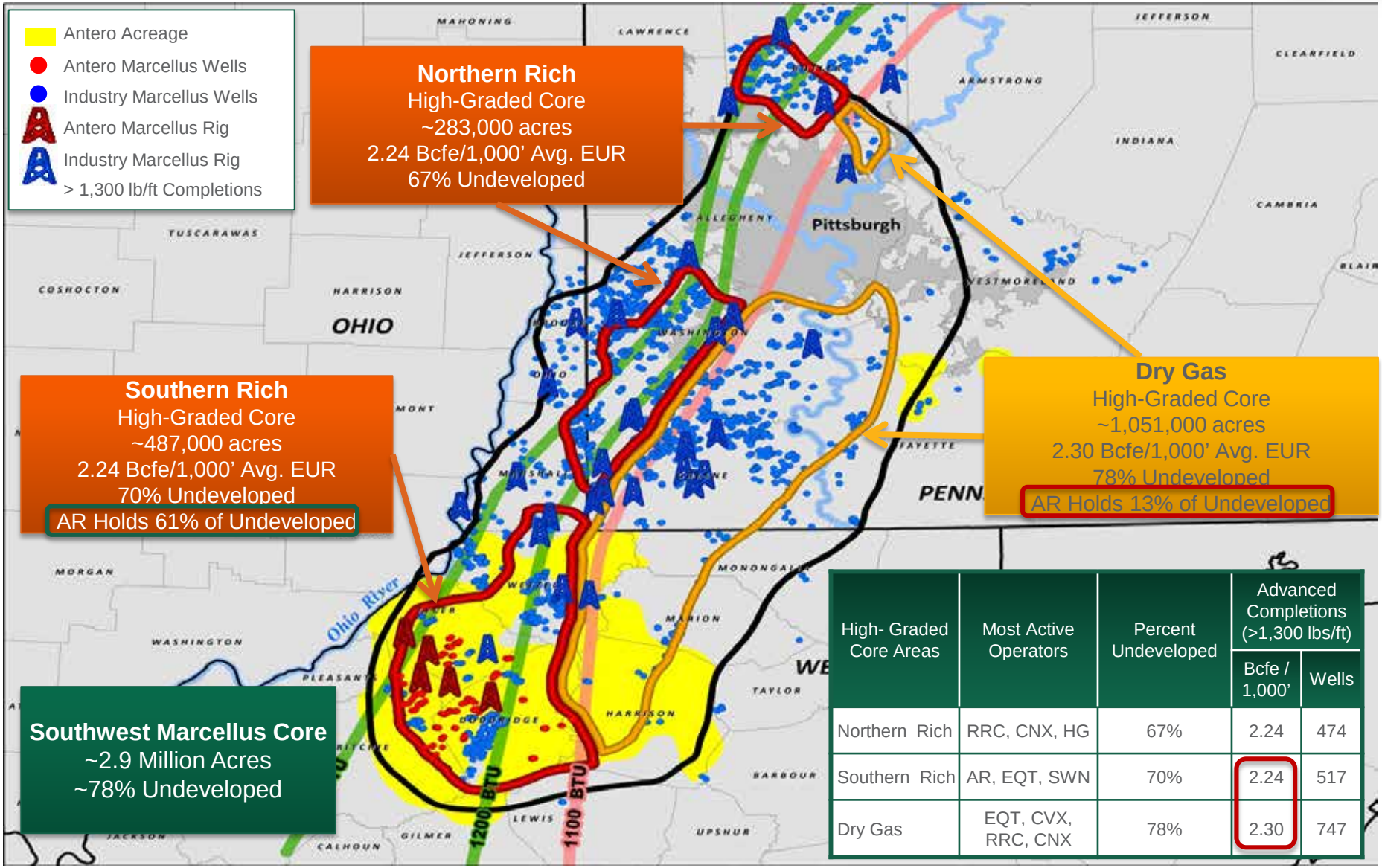


Free Cash Flow Yields Exceed Both Best-In-Class Peers & Integrated Oil & Gas Companies

Note: See definitions for free cash flow and assumptions behind long-term targets in Appendix. "Elite" group of peers includes COG, CXO, EOG, FANG, PXD, XEC; "Integrated" group includes XOM & CVX.
Source: Bloomberg. Represents free cash flow yield for the base case at 12/31/17 strip pricing.
(1) Represents free cash flow divided by current market capitalization as of 4/30/18.

Scale & Growth: Liquids-Rich Resource Meets Capital Efficiency

Positioned in the Core of the Core



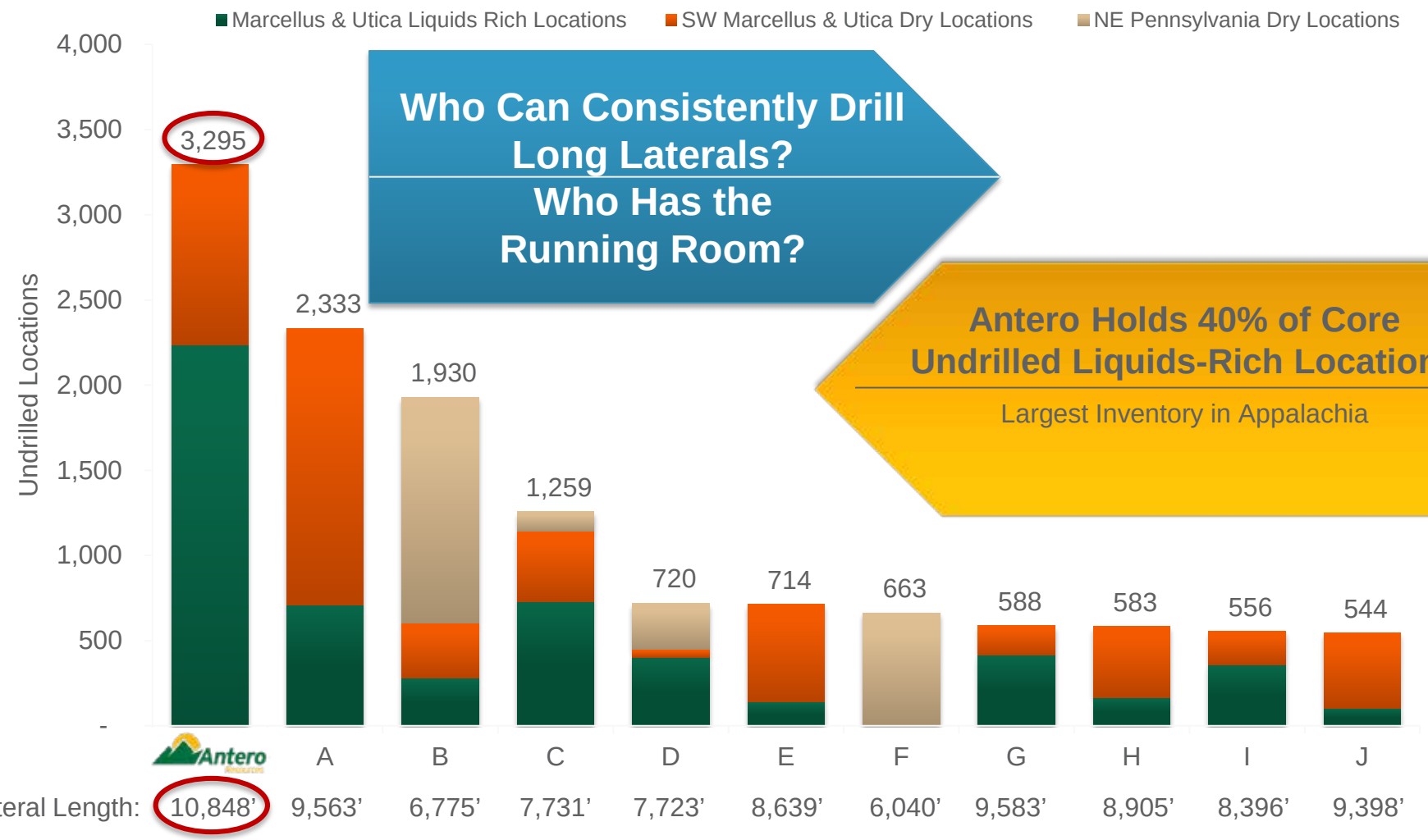
High- Graded Core Areas	Most Active Operators	Percent Undeveloped	Advanced Completions (>1,300 lbs/ft)	
			Bcfe / 1,000'	Wells
Northern Rich	RRC, CNX, HG	67%	2.24	474
Southern Rich	AR, EQT, SWN	70%	2.24	517
Dry Gas	EQT, CVX, RRC, CNX	78%	2.30	747

Antero is Very Well Positioned in the Core of the Core

Note: Core area excludes 600,000 urban acres mostly around Pittsburgh, PA. EURs assume full ethane rejection. Based on Antero reserve engineering of most recent state and internal production data.

Largest Undrilled Core Drilling Inventory

Undrilled Core Marcellus & Utica Locations(1)



Who Can Consistently Drill Long Laterals?

Who Has the Running Room?

Antero Holds 40% of Core Undrilled Liquids-Rich Locations

Largest Inventory in Appalachia

(1) *Peers include Ascent, CHK, CNX, COG, CVX, EQT, GPOR, HG, RRC and SWN. Based on Antero analysis of undeveloped acreage in the core of the Marcellus and Utica plays.*

A Pioneer in Longer Lateral Development in Appalachia

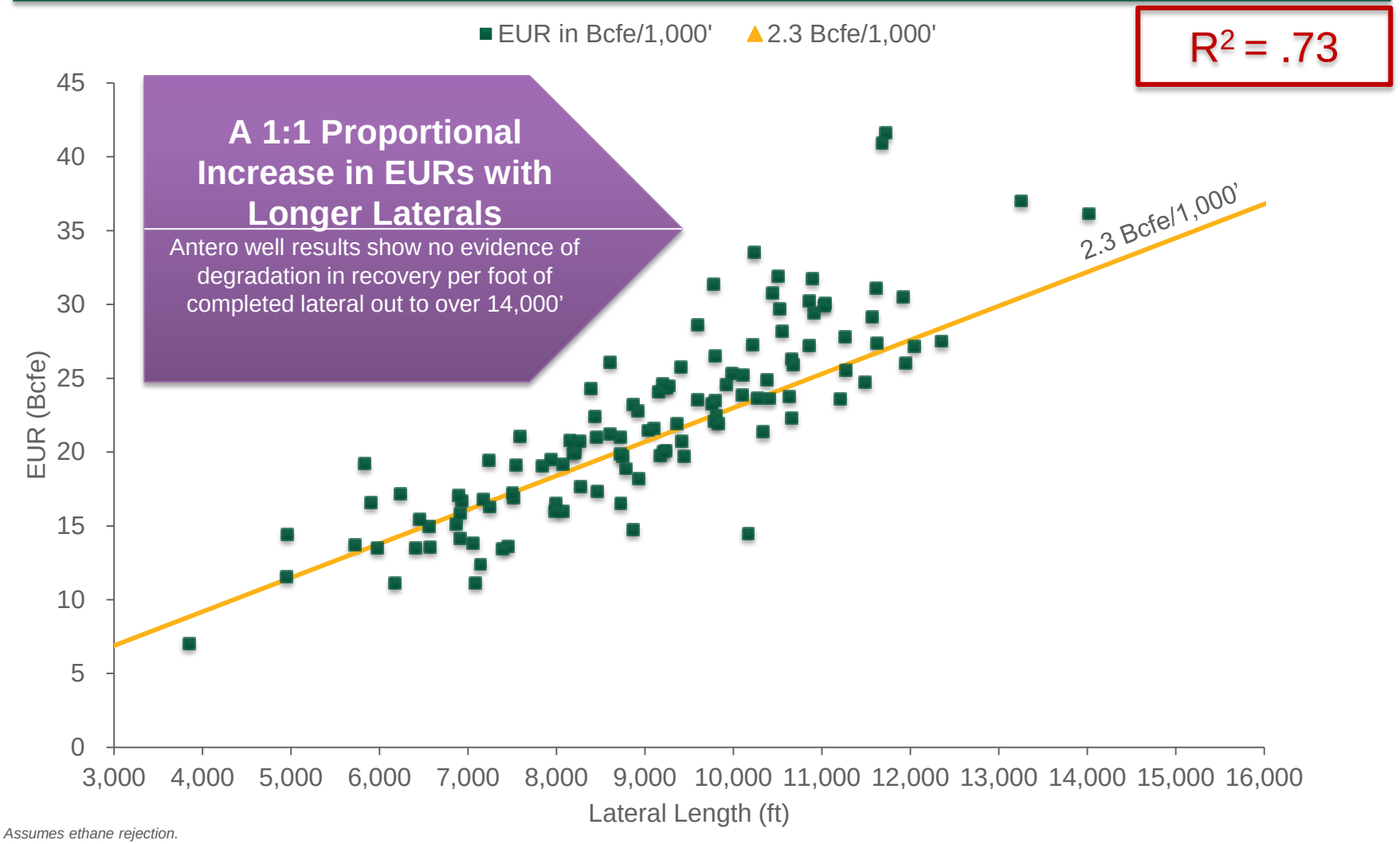
Antero Historical & Future Lateral Length Program

Antero	# of Wells	Avg. Lateral Length
Total Drilling Program to Date	945	8,275
2018-2022 Program(2)	790	11,425
Wells to Date ≥10,000'	245	10,700

(1) *All laterals rounded to the nearest thousand.*
(2) *Represents wells placed to sales.*

Longer Laterals Scale the Resource

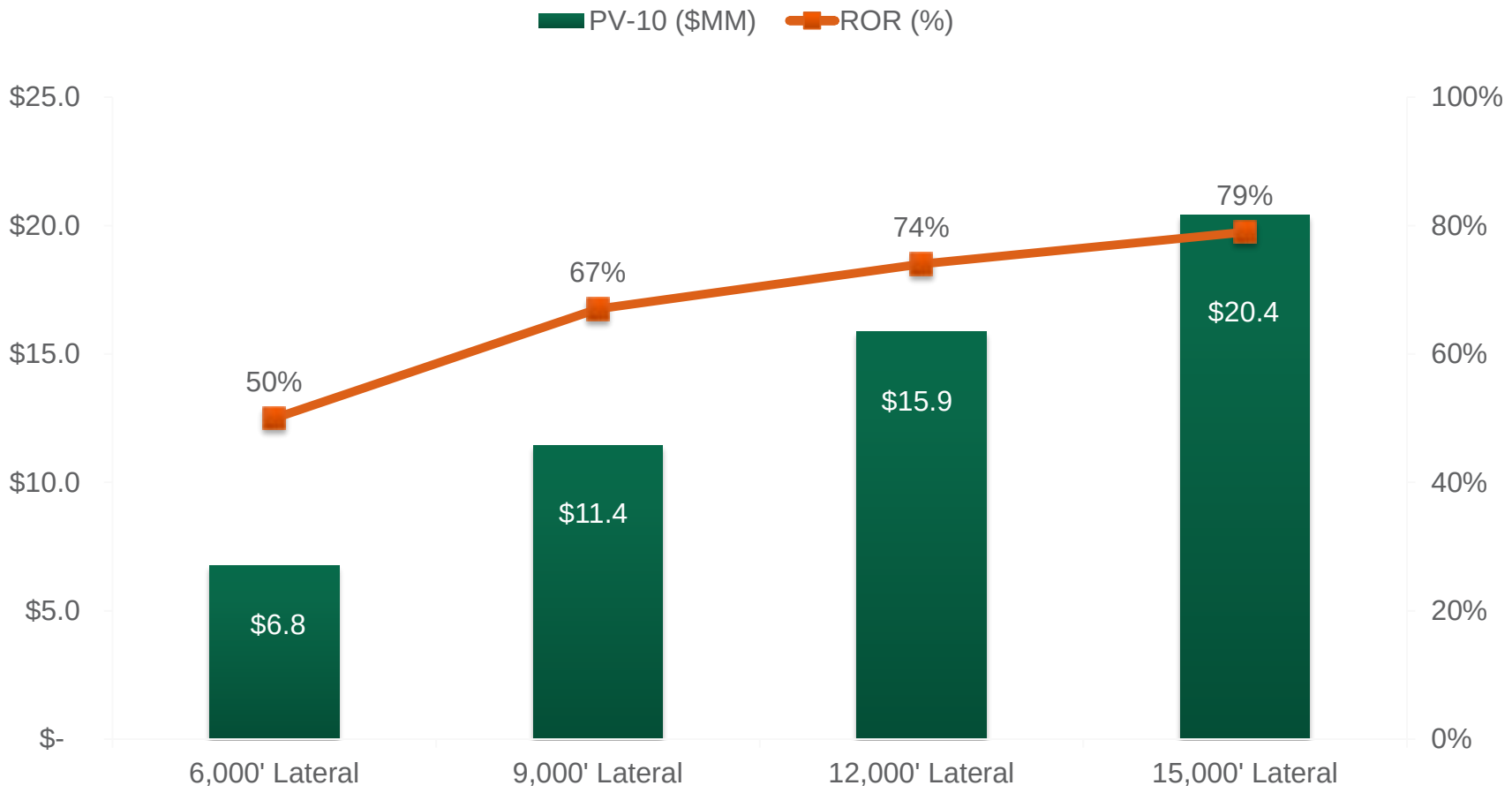
EURs by Marcellus Lateral Lengths



Note: Assumes ethane rejection.

The Longer, the Better…

Single Well Economics by Lateral Lengths



~60% Improvement in ROR from a 6,000’ Lateral to a 15,000’ Lateral

Note: Represents half cycle economics at YE 2017 strip pricing for a 1250 Btu Marcellus well. See Appendix for further assumptions on single well economics.

Declining Well Costs → Longer Laterals the Next Step

41% | 43% Lower Costs

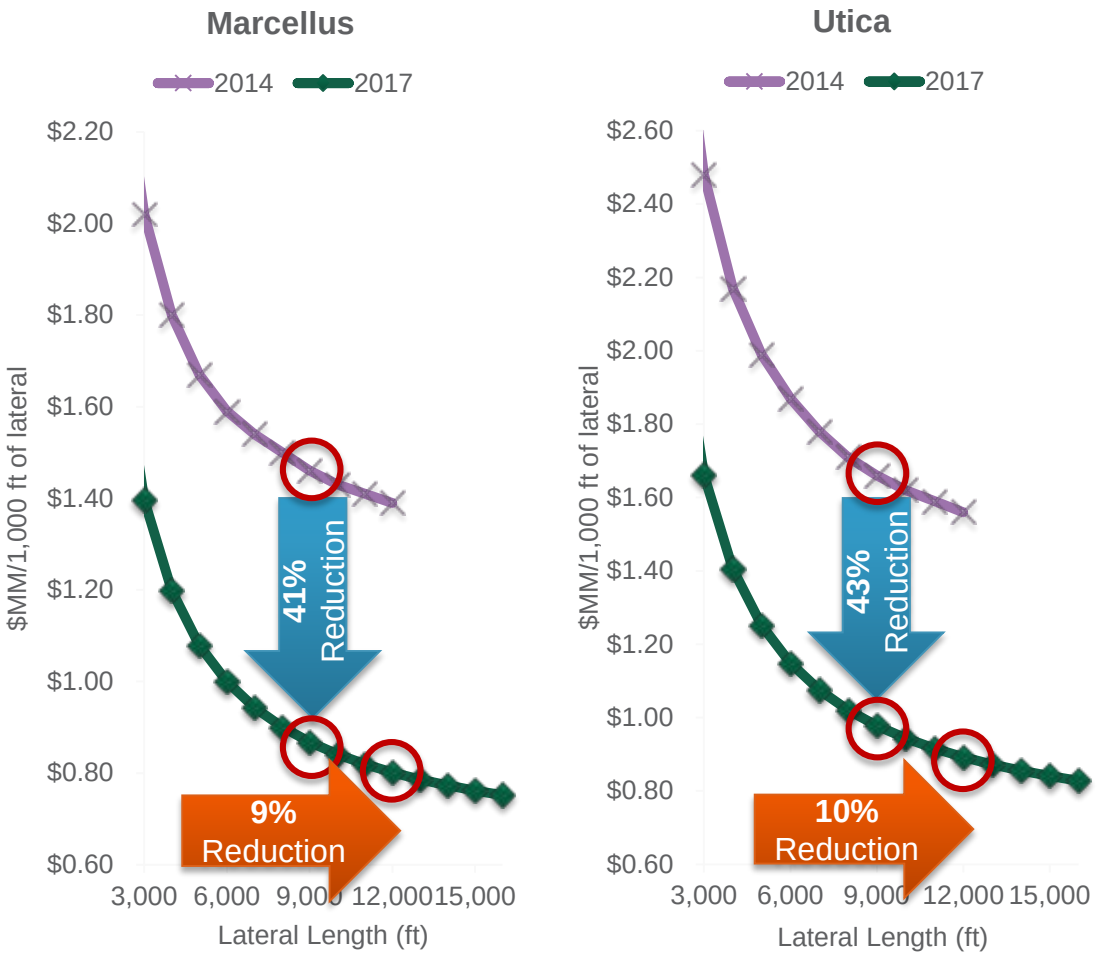
Marcellus | Utica reduction in well costs from 2014 to 2017 for a 9,000' lateral

- 54% from efficiencies
- 45% from service costs

9% | 10% Cost Benefit

Marcellus | Utica reduction in well cost per 1,000' lateral going from 9,000' to 12,000' laterals

Historical Well Costs



Note: Well costs reflect 2,000 pound per foot completions. See Appendix for further assumptions.

Operating Evolution Continues

Achievements to Date

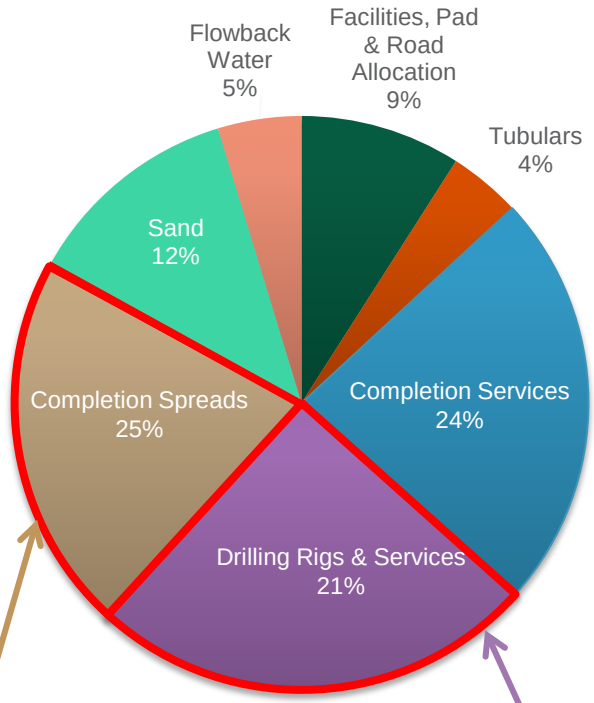
42%
Decline in well costs since 2014

=

46%
Vendor-related cost reductions

54%
Permanent cost efficiencies

2018 Marcellus Well Cost(1)



100% of Completion Spreads Under Contract Through 2019

Antero has 100% of 2018 Rigs and 50% of 2019 Rigs Under Fixed Rate Contracts with Average Rig Rates Declining Towards $17,500/day in 2018 as Higher Rig Rate Contracts Roll Off

Next Steps in Efficiency Evolution

Drilling Rigs/Services

→ Fit-for-purpose rigs with dual operation capabilities to improve cycle times

→ Improved drillout efficiency

→ Penetration rates still increasing with new downhole motors

Completion Spreads/Services

→ Concurrent operations with larger pads allowing simultaneous drilling and completion and easier access

→ More wells per pad

→ Automated completion equipment to increase stages per day

Sand

→ 100 mesh sand for easier pumping & fewer screenouts

→ Self-sourcing sand to reduce supply cost

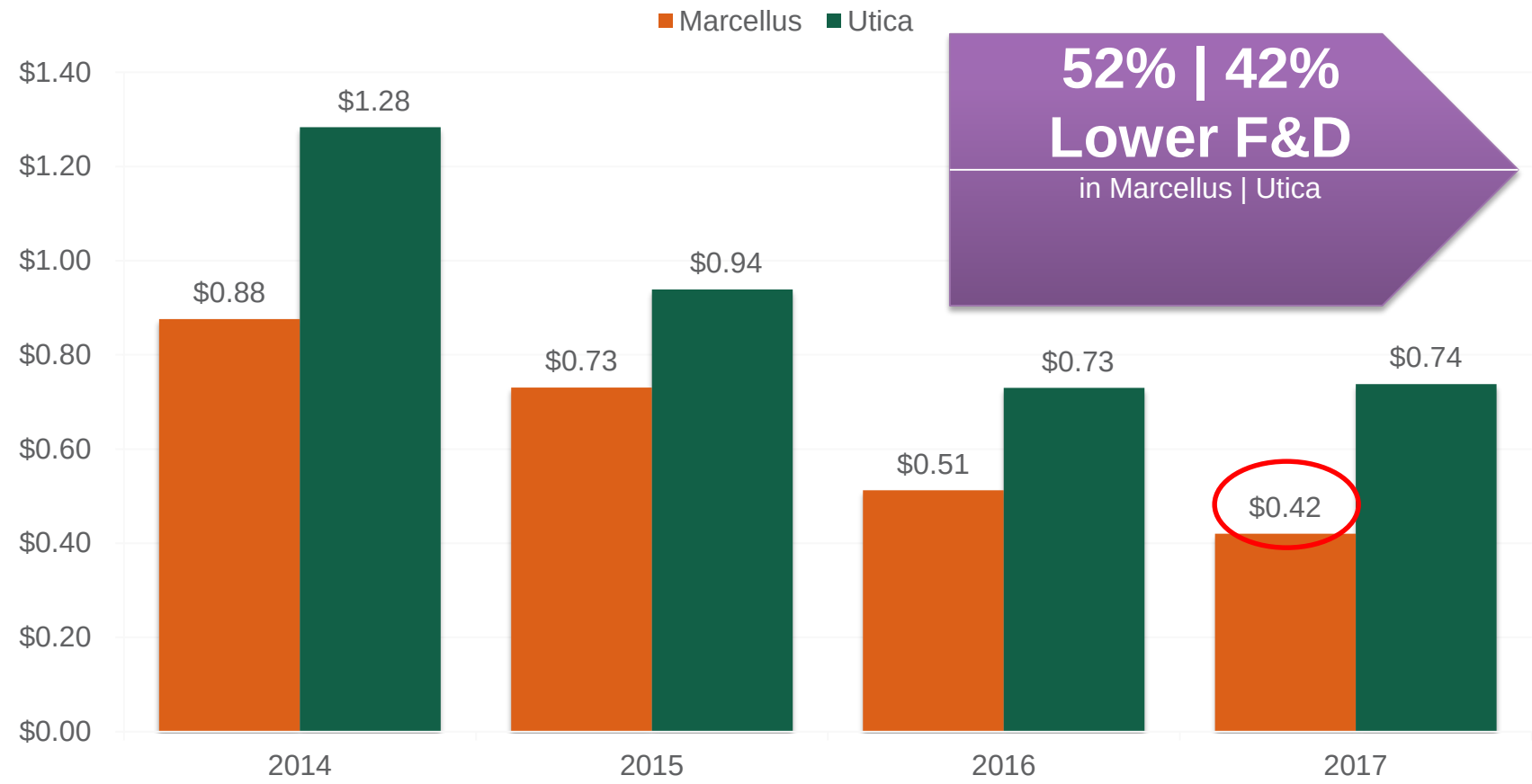
→ Regional sand mines in the Permian expected to reduce demand for Northern White sand

Efficiencies Expected to Offset Service Cost Inflation

(1) *Based on Marcellus 11,000 foot lateral and 2,000 pounds per foot AFE. Assumes nine wells per pad.*

Dramatically Lower F&D Cost

F&D Cost per Mcfe(1)(2)

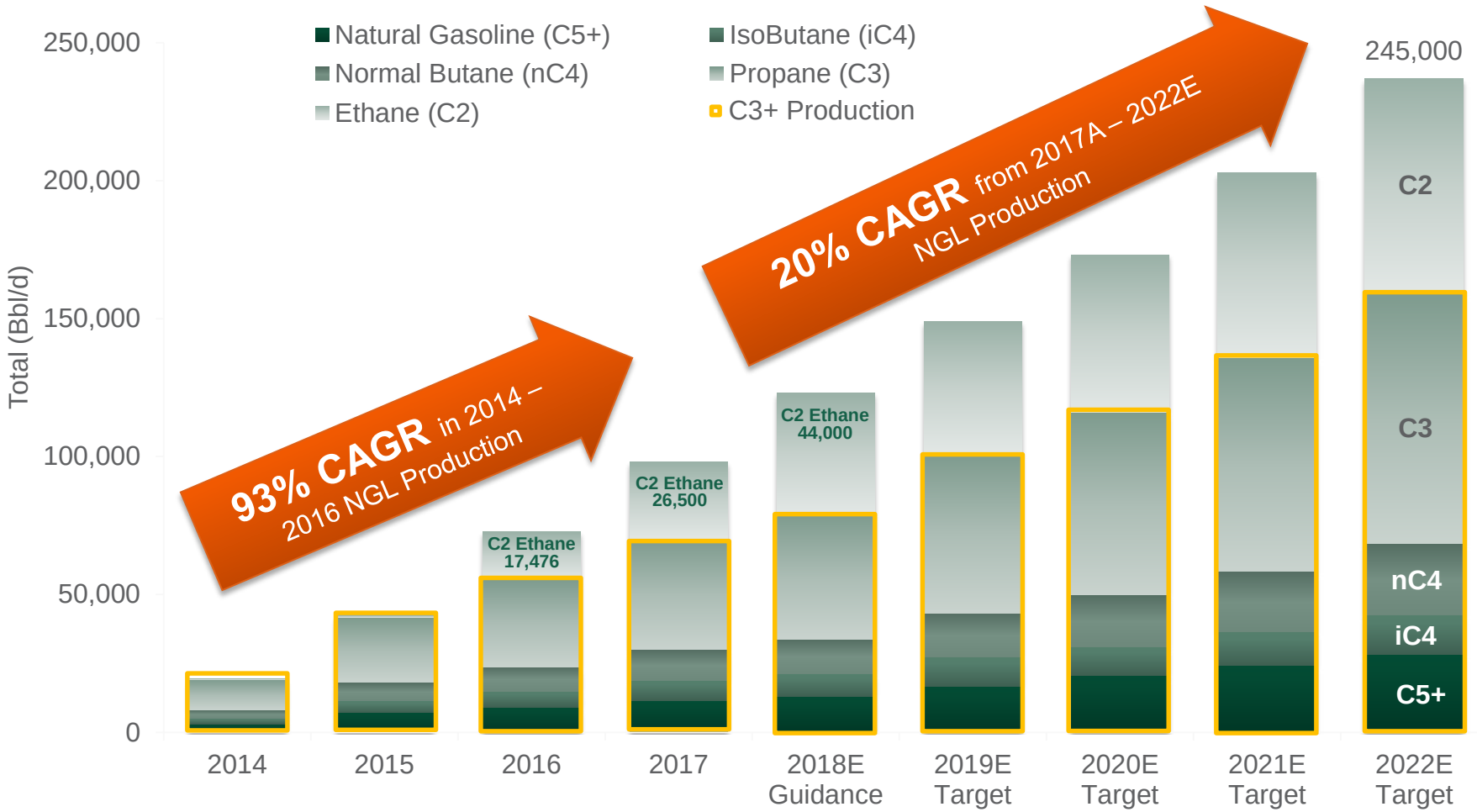


Dramatic Improvement in Operating Efficiencies, Lower Service Costs and Higher Well Recoveries Have Driven F&D Costs Materially Lower

(1) *Ethane rejection assumed.*
(2) *F&D cost is defined as current D&C cost per 1,000' lateral divided by net EUR per 1,000' lateral assuming 85% NRI in Marcellus and 81% NRI in Utica. Please see "Antero Definitions" and "Antero Non-GAAP Measures" in the Appendix.*

Rapidly Growing NGL Production

Antero NGL Production Growth by Purity Product



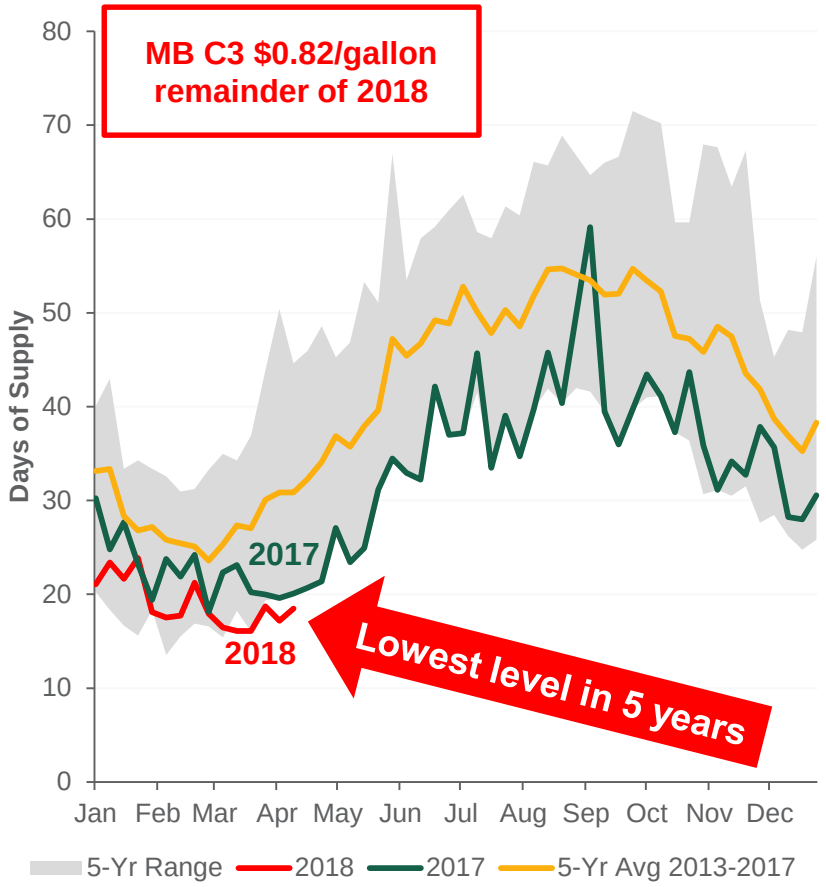
Note: Excludes condensate. See Appendix for further assumptions around long-term targets.

Strong Propane Fundamentals

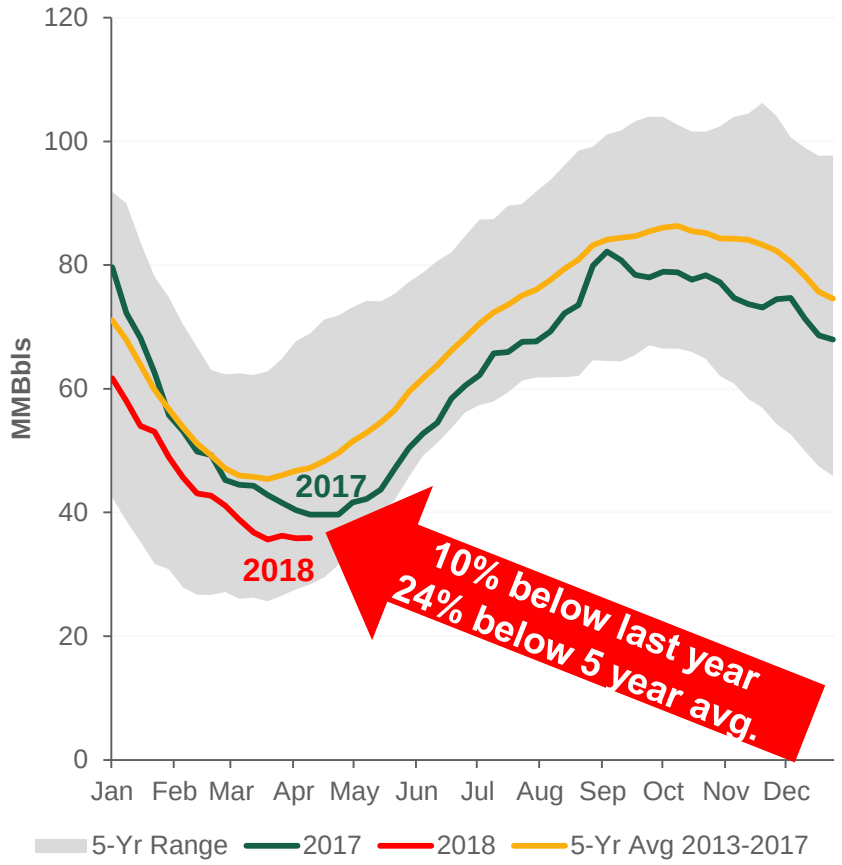
Current propane days of supply are 8% below last year and 40% below the 5-year average

Material reduction in U.S. propane inventories relative to the 5-year average

Propane Days of Supply



U.S. Propane Inventories

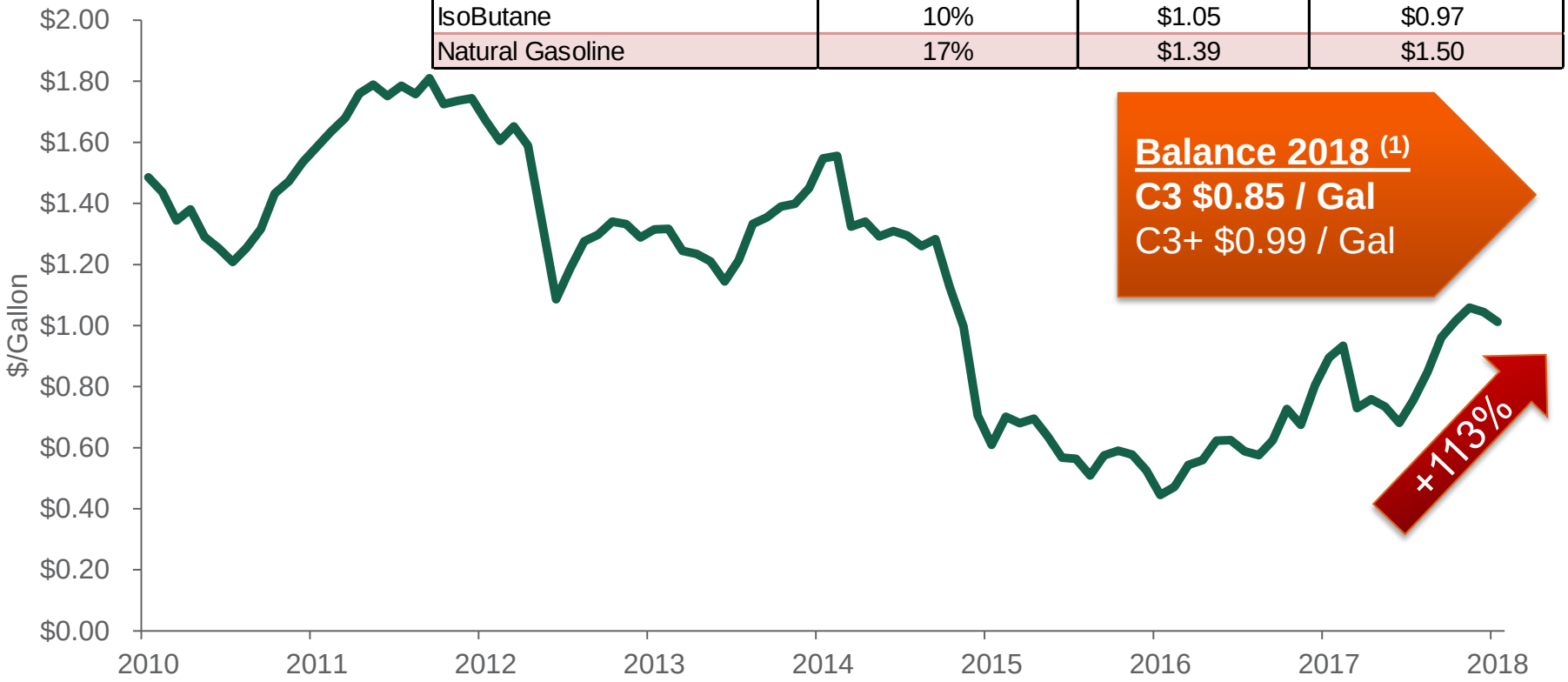


Source: EnVantage Inc. and Energy Information Administration (EIA).

C3+ NGLs: Price Improvement

Strong NGL Prices Expect to Continue Through 2018

Mont Belvieu Product Pricing ($/Gallon)			
	AR C3+ Barrel	1Q 2018 Actuals	Balance 2018 (1)
Propane	57%	$0.87	$0.85
N. Butane	16%	$0.84	$0.96
IsoButane	10%	$1.05	$0.97
Natural Gasoline	17%	$1.39	$1.50

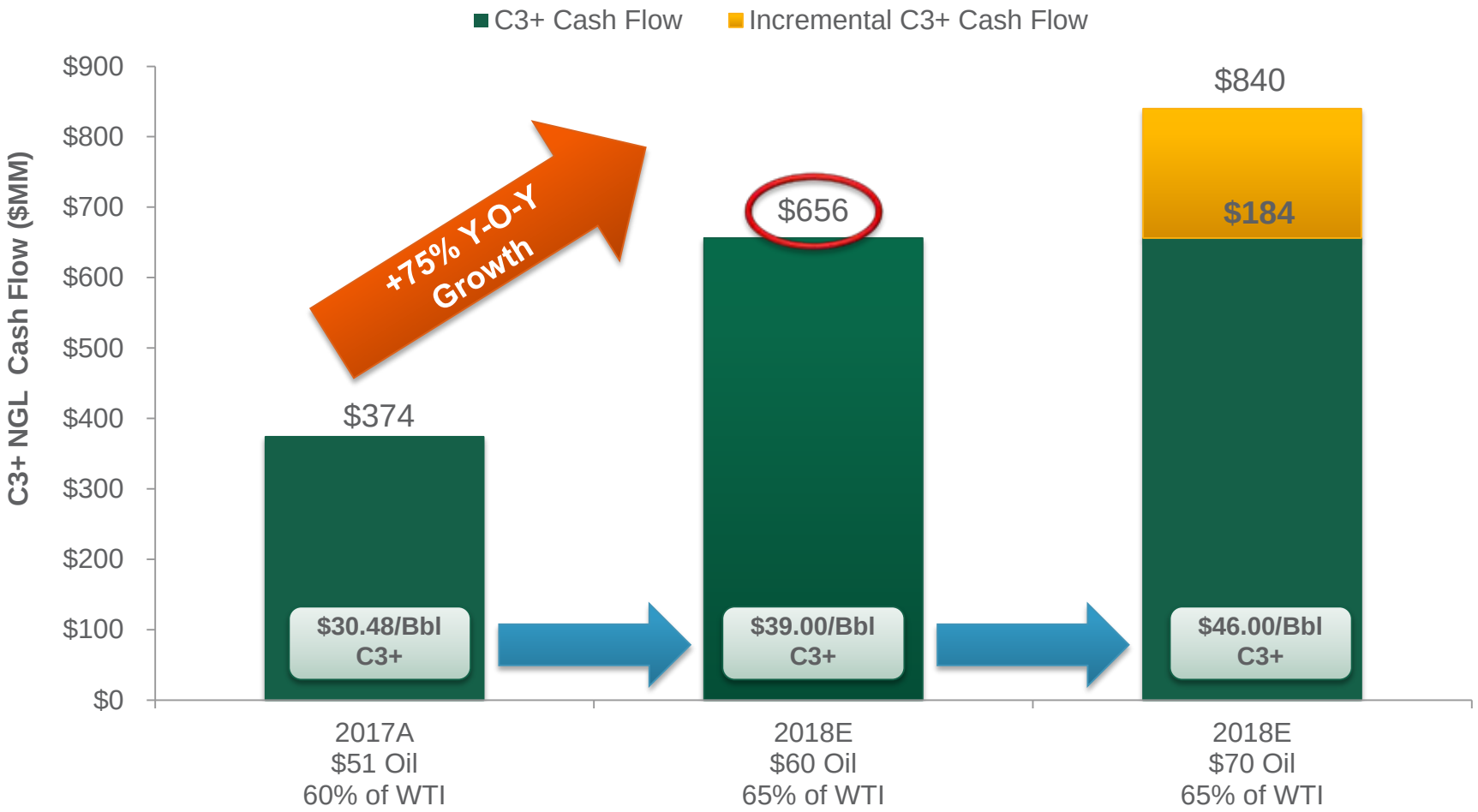


Tightening Inventories and Increasing Exports, Along With an Increase in Global Product Prices, Have Resulted in an Improvement in C3+ Prices

Source: Intercontinental Exchange (ICE) pricing data. Assumes C3+ barrel weightings of: propane 57%, normal butane 16%, Isobutane 10%, pentanes 17%.
1) Balance 2018 represents strip pricing as of 4/30/2018. C3+ assumes C3+ barrel weightings of: propane 57%, normal butane 16%, Isobutane 10%, pentanes 17%.

Powerful C3+ NGL Pricing Upside Exposure

Significant Upside to C3+ NGL Pricing (2018 vs. 2017)

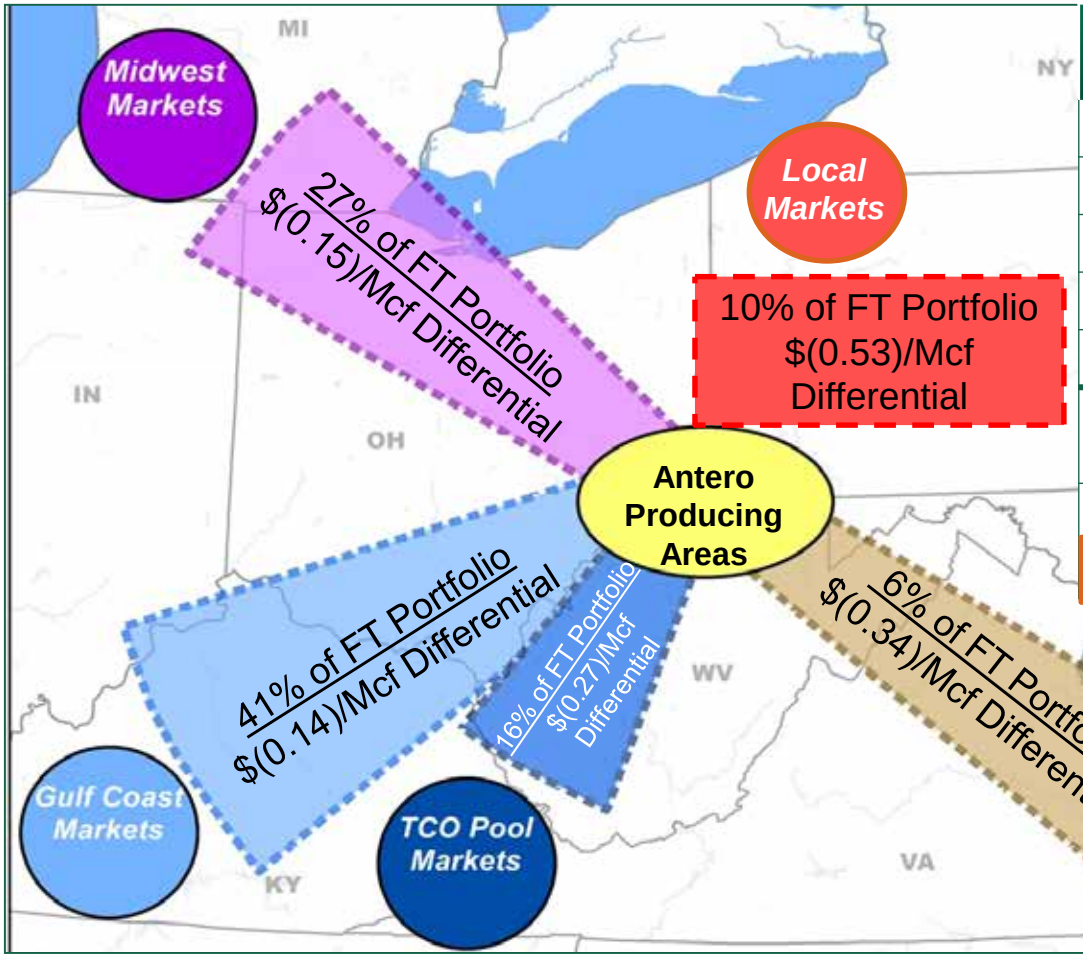


Antero Expects Significant Cash Flow Growth in 2018 From the Improvement in NGL Pricing With Attractive Upside to Further Increases in Liquids Pricing

Note: C3+ NGL cash flow represents revenue from C3+ NGL production, less processing, transportation and all other operating costs associated with C3+ NGL production and sales.

Diversified Natural Gas Market Mix

Antero Firm Transportation Portfolio in 2018



Index	Differential	% of Gas Sold
TETCO M2	$(0.53)	10%
Mid-Atlantic	$(0.34)	6%
TCO	$(0.27)	16%
Gulf Coast	$(0.14)	41%
Midwest	$(0.13)	27%
Weighted Average vs. NYMEX:	$(0.21)	100%
BTU Uplift	$0.24	
All-in vs. NYMEX	+$0.03	

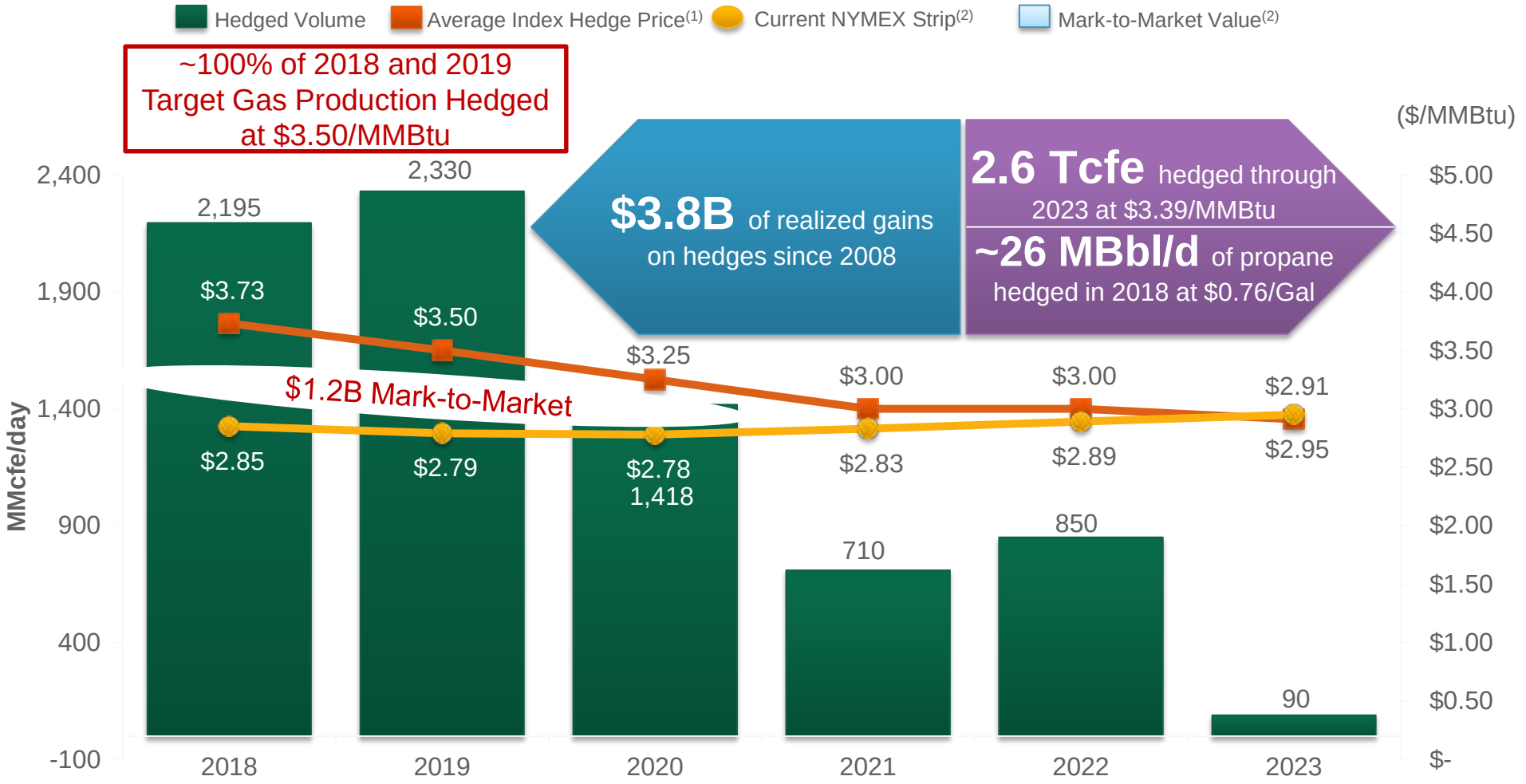
+$0.00 - $0.05
forecasted premium to NYMEX after BTU uplift

90% of Antero Gas Is Sold In Favorably Priced Markets

Note: Based on 2018 strip pricing as of 12/31/2017. See Appendix for further assumptions.

Well Hedged at High Prices Relative to Strip

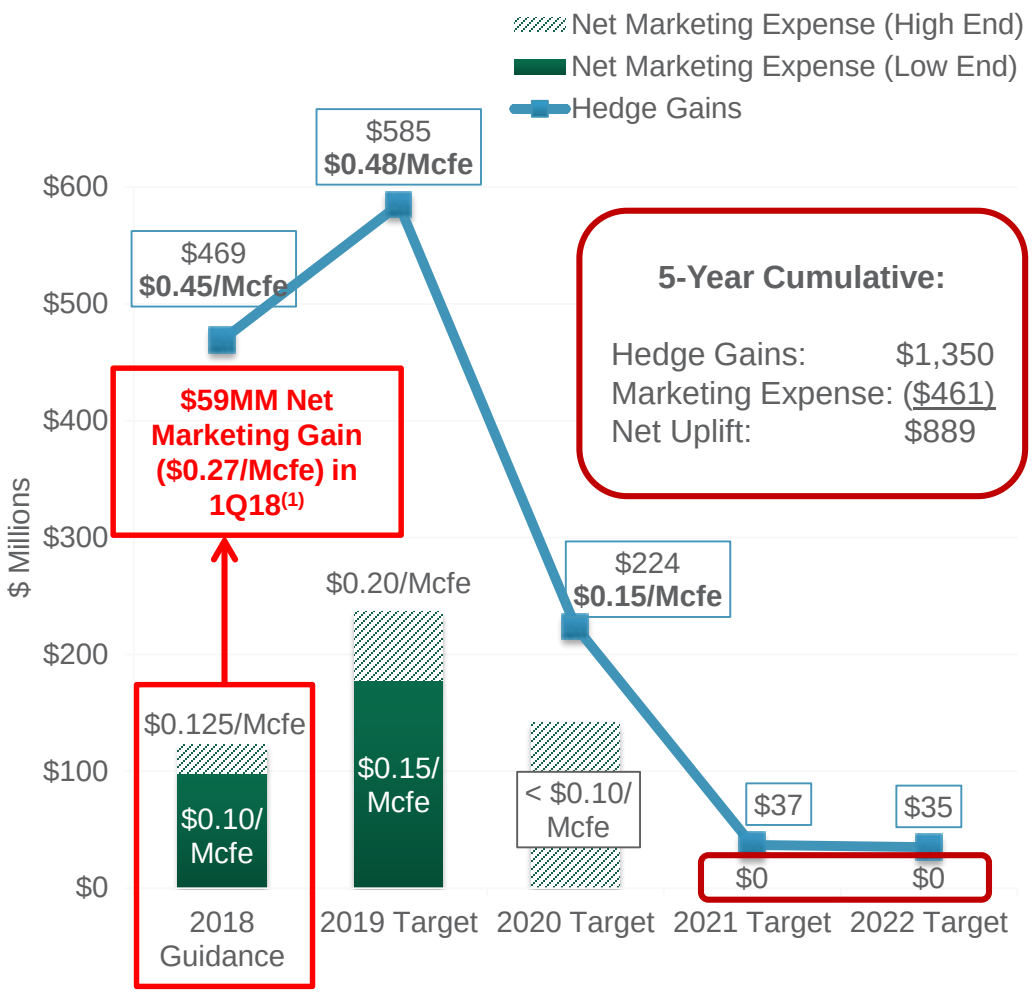
Commodity Hedge Position



~$1.2B Mark-To-Market Unrealized Gains Based On 3/31/2018 Prices

(1) *Weighted average index price based on volumes hedged assuming 6:1 gas to liquids ratio. Includes 26,000 Bbl/d of propane hedged at $0.76/gallon and 6,000 Bbl/d of oil hedged at $56.99/Bbl for 2018 only.*
(2) *As of 3/31/18.*

A Paired Trade – Hedges Support Firm Commitments



Hedge Portfolio Supports Firm Commitments

Firm Transportation Portfolio

Allows Antero to achieve:

Premium Price Certainty

Less volatility and greater surety in realized prices

Effectively Hedge NYMEX Index

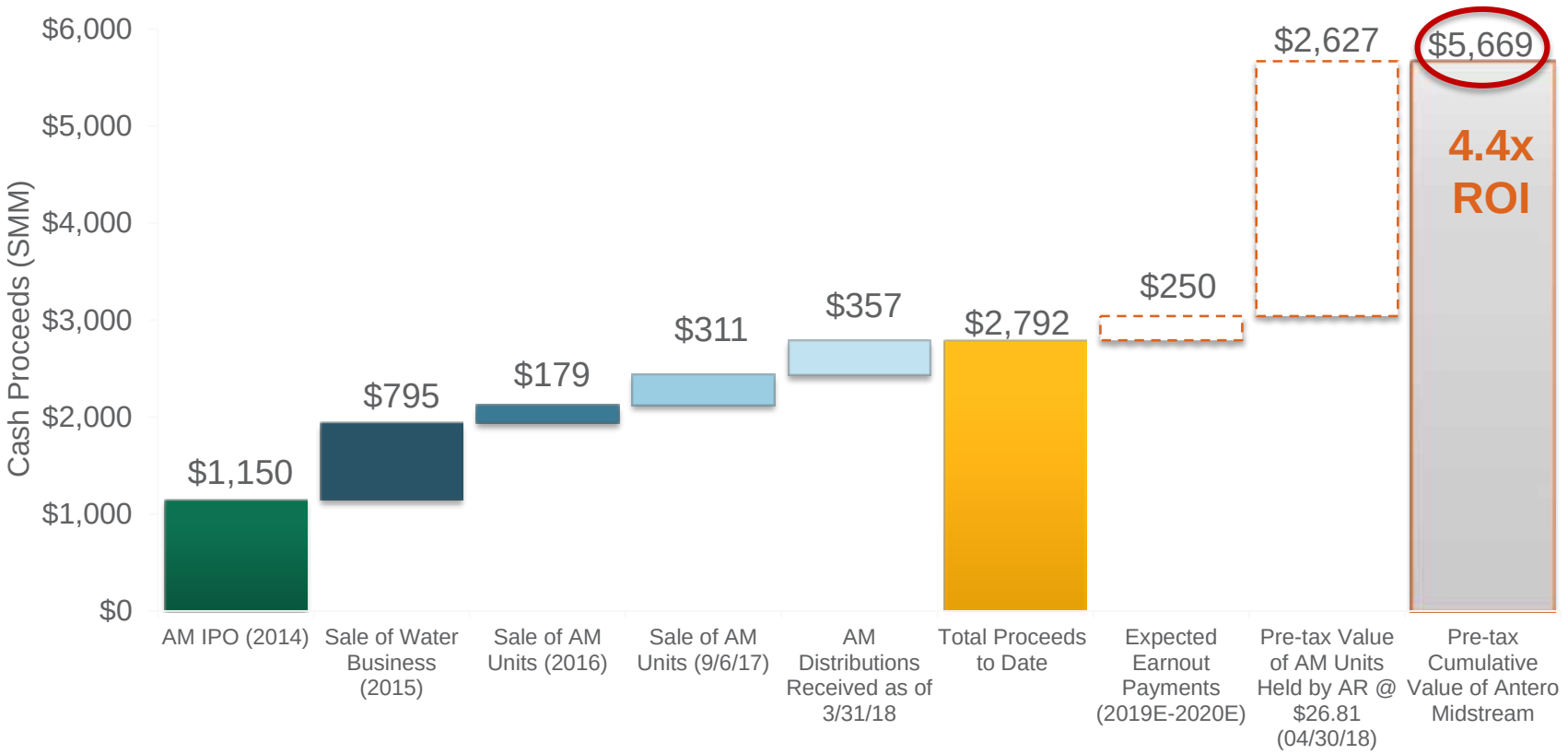
A key advantage as our product is delivered to NYMEX-related markets

Hedge Gains More than Offset Marketing Expense – Hedges Support FT Commitments

(1) *Excludes unrealized marketing derivative losses of $16 million.*

Midstream Driving Value for AR Since Inception

Antero Midstream Return on Investment for AR (Pre-tax)(1)

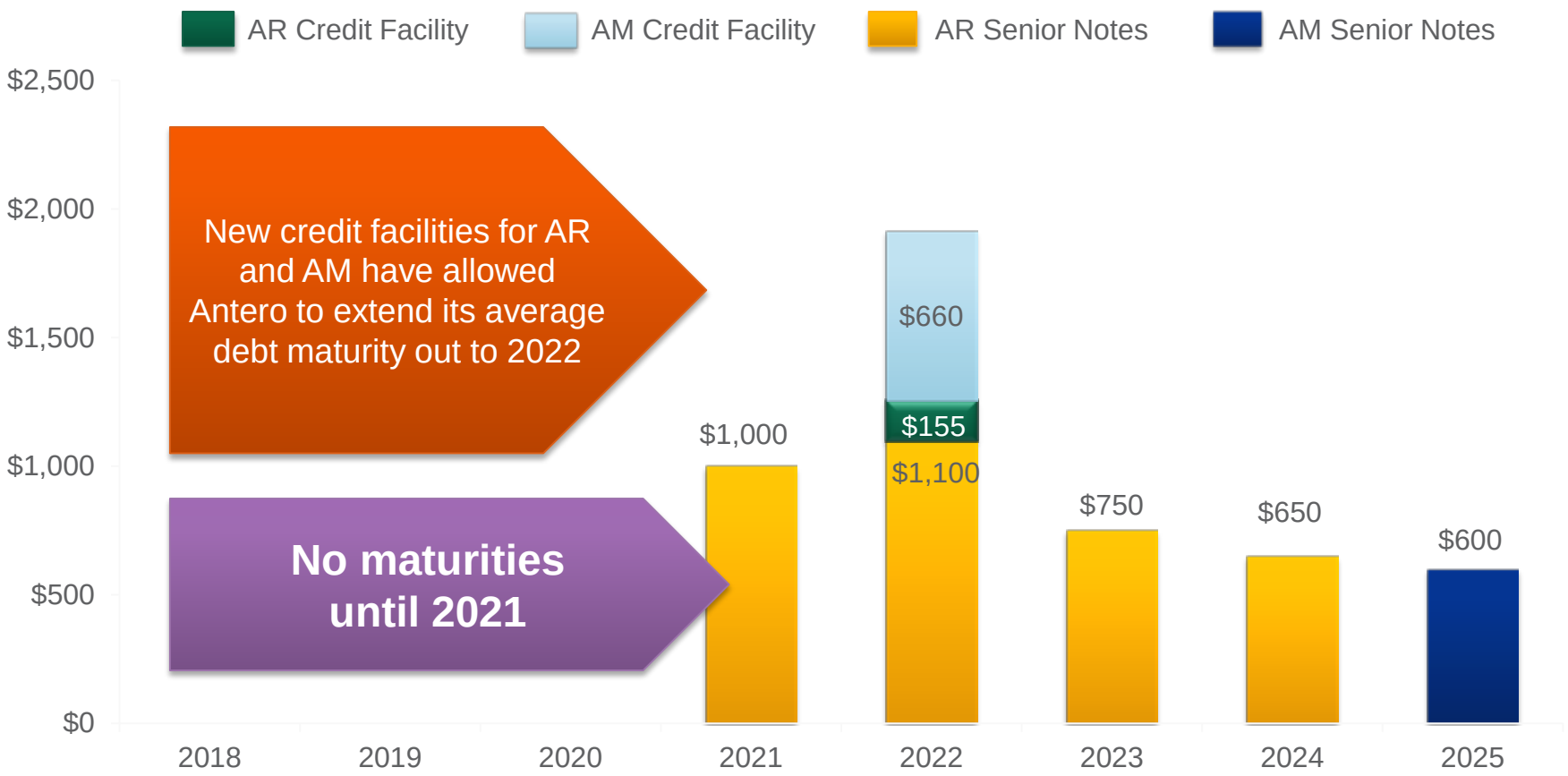


Takeaway Assurance → Downstream Visibility → Return on Investment

(1) Midstream proceeds received by AR to date plus market value of AR's 53% ownership of AM at 4/30/18 divided by the approximate $1.3B of AR capital invested at time of AM IPO.

Liquidity & Debt Term Structure

3/31/2018 Debt Maturity Profile

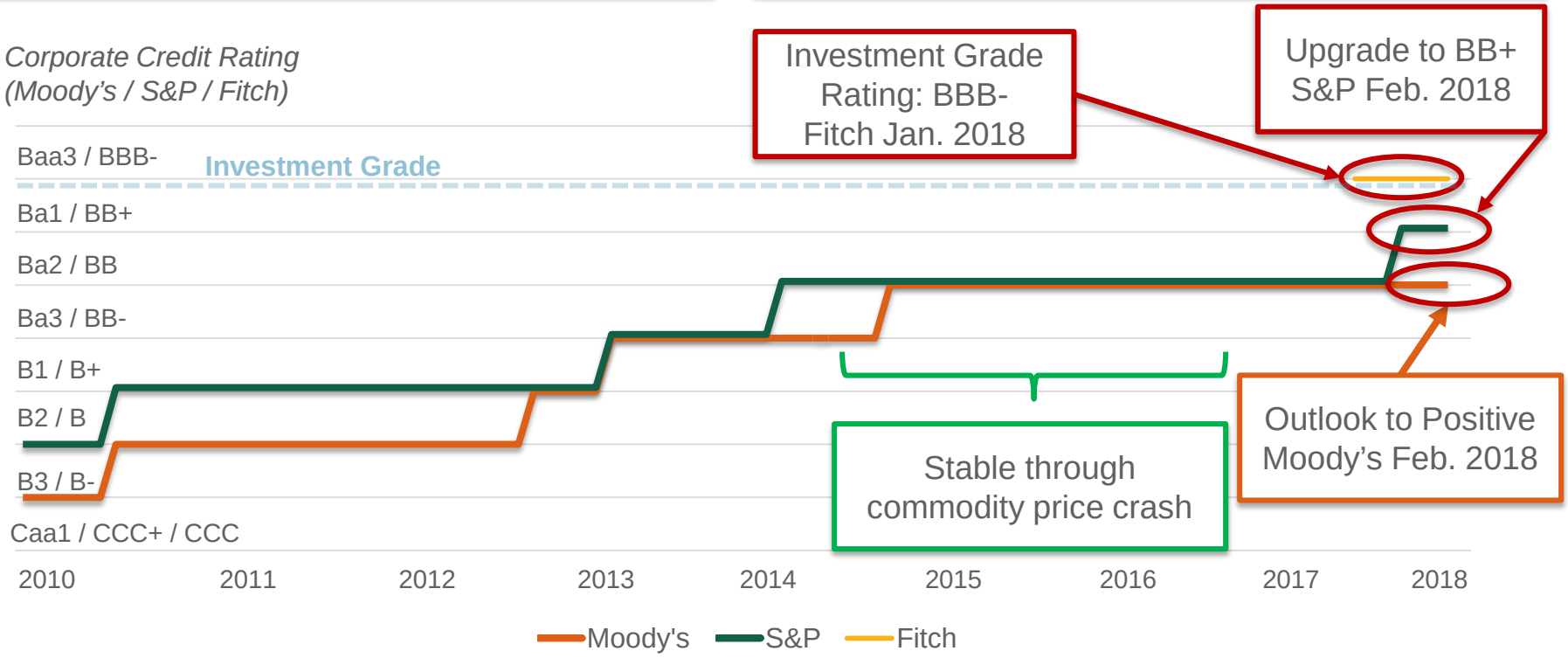


Deleveraging is Driving Ratings Momentum

Corporate Credit Ratings History

Stable Credit Ratings with Consistent Upgrades from the Beginning of the Decade Through the Downturn

Investment Grade Rating from Fitch (BBB-) & Recent Upgrade from S&P (BB+)



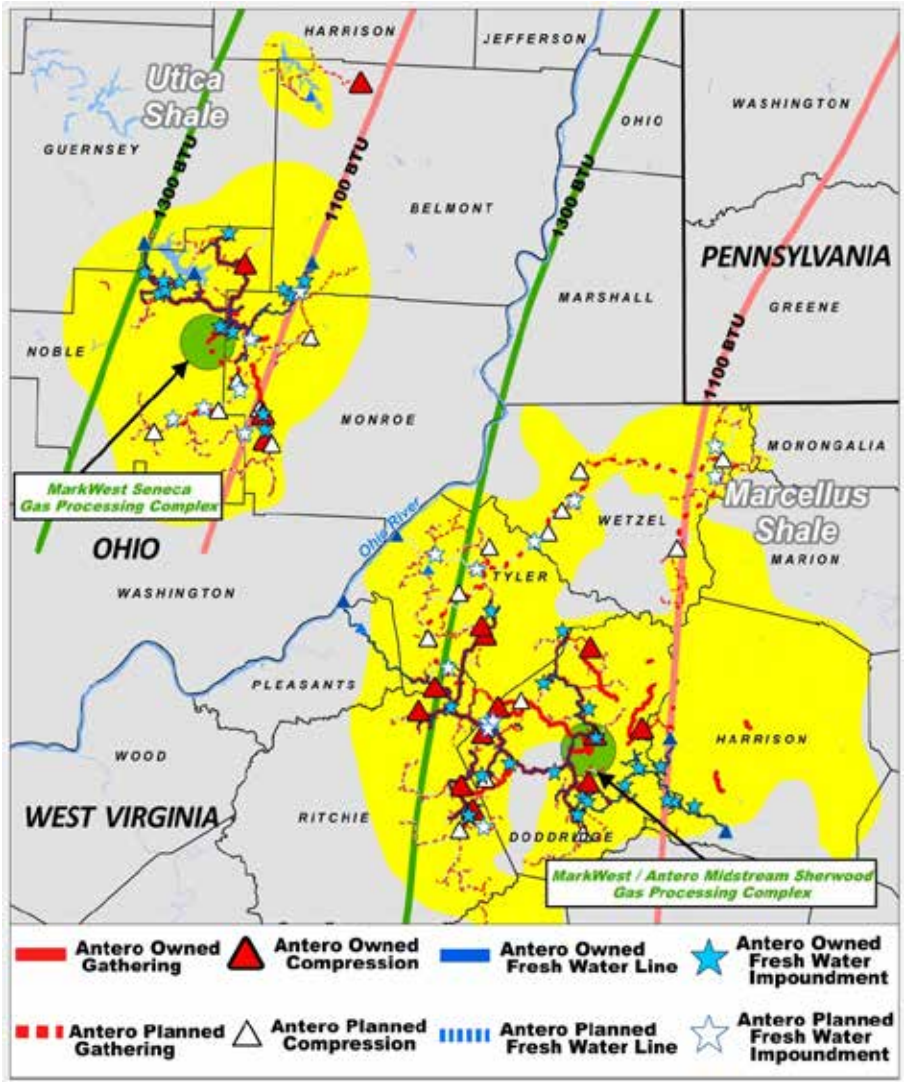
Credit Markets Have a Strong Appreciation for Antero Momentum

Antero Midstream Overview: Disciplined Capital Efficient Business Model

Antero Midstream At A Glance

Market Cap……..	$5.0B
Enterprise Value…..……	$6.3B
LTM Adjusted EBITDA(1)……..	$571 MM
% Gathering/Compression	66%
% Water	34%
Net Debt/LTM EBITDA……..	2.3x
Corporate Debt Rating…….	Ba2 / BB+ /BBB-
Gross Dedicated Acres(2)…….	705,000

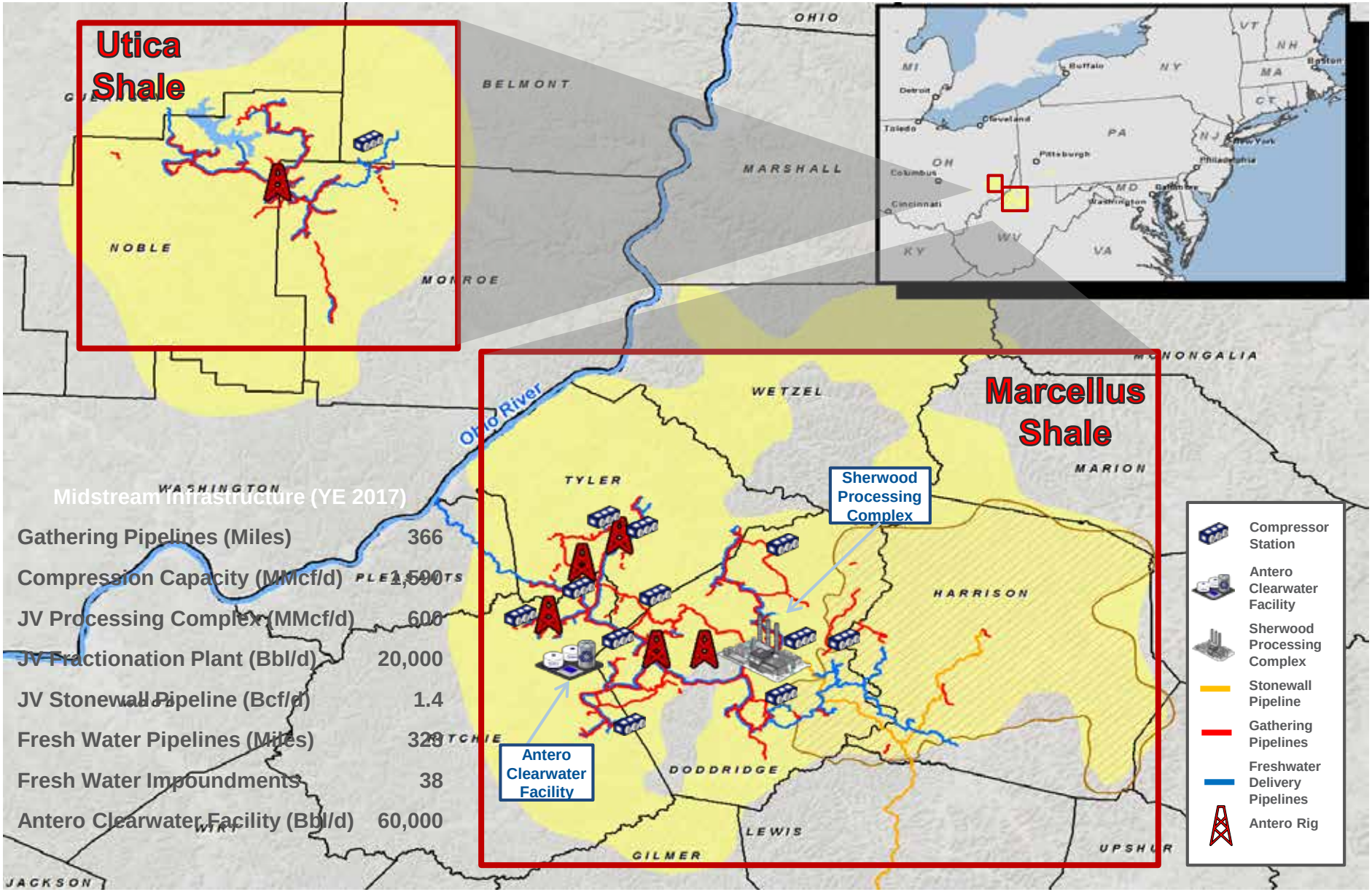
AM
LISTED
NYSE



Note: Equity market data as of 4/30/2018. Balance sheet data as of 3/31/2018.

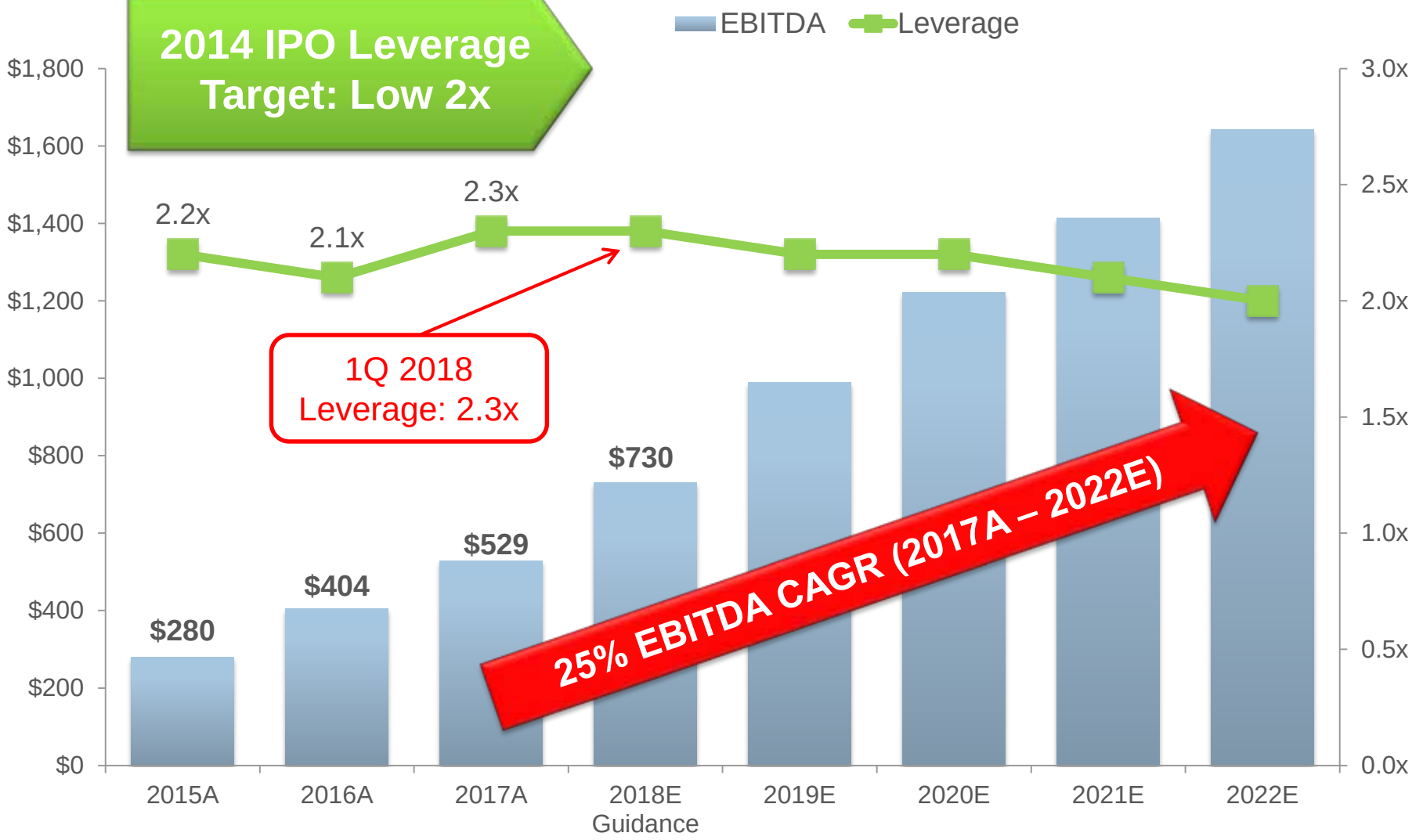
1. *LTM Adjusted EBITDA as of 3/31/18. Adjusted EBITDA is a non-GAAP measure. For additional information regarding this measure, please see "Antero Midstream Non-GAAP Measures" in the Appendix.*
2. *Represents acres dedicated for gathering and compression. Excludes 156,000 gross acres dedicated to third parties for gathering and compression services.*

Antero Midstream Asset Overview – Year End 2017



Disciplined EBITDA Growth

AM EBITDA and Leverage



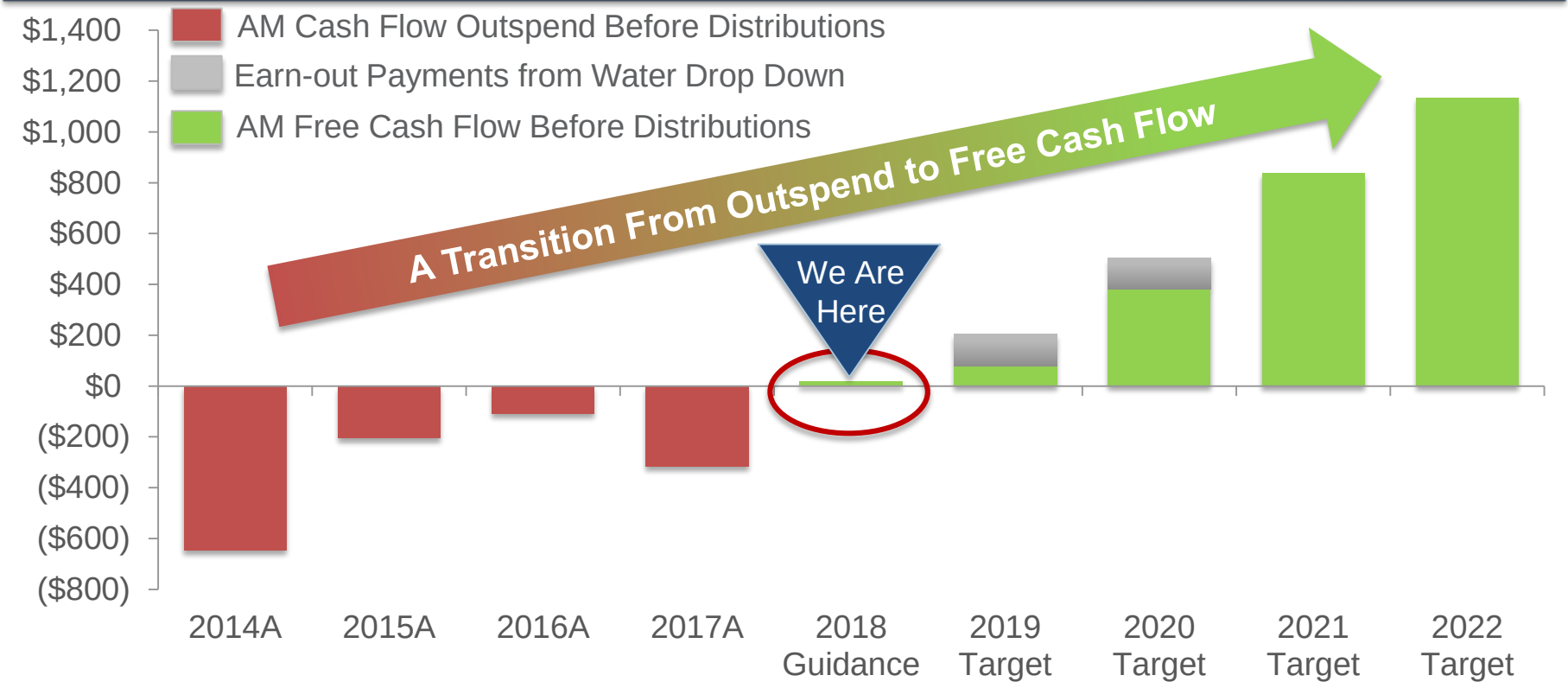
Capital Efficiency Drives Free Cash Flow Generation

~$500MM in Capital Efficiencies

With No Change to Throughput Volumes

Leverage existing asset base and realization of "full build-out EBITDA multiples"

Over $2.4 billion of Free Cash Flow from 2018 – 2022 Before Distributions



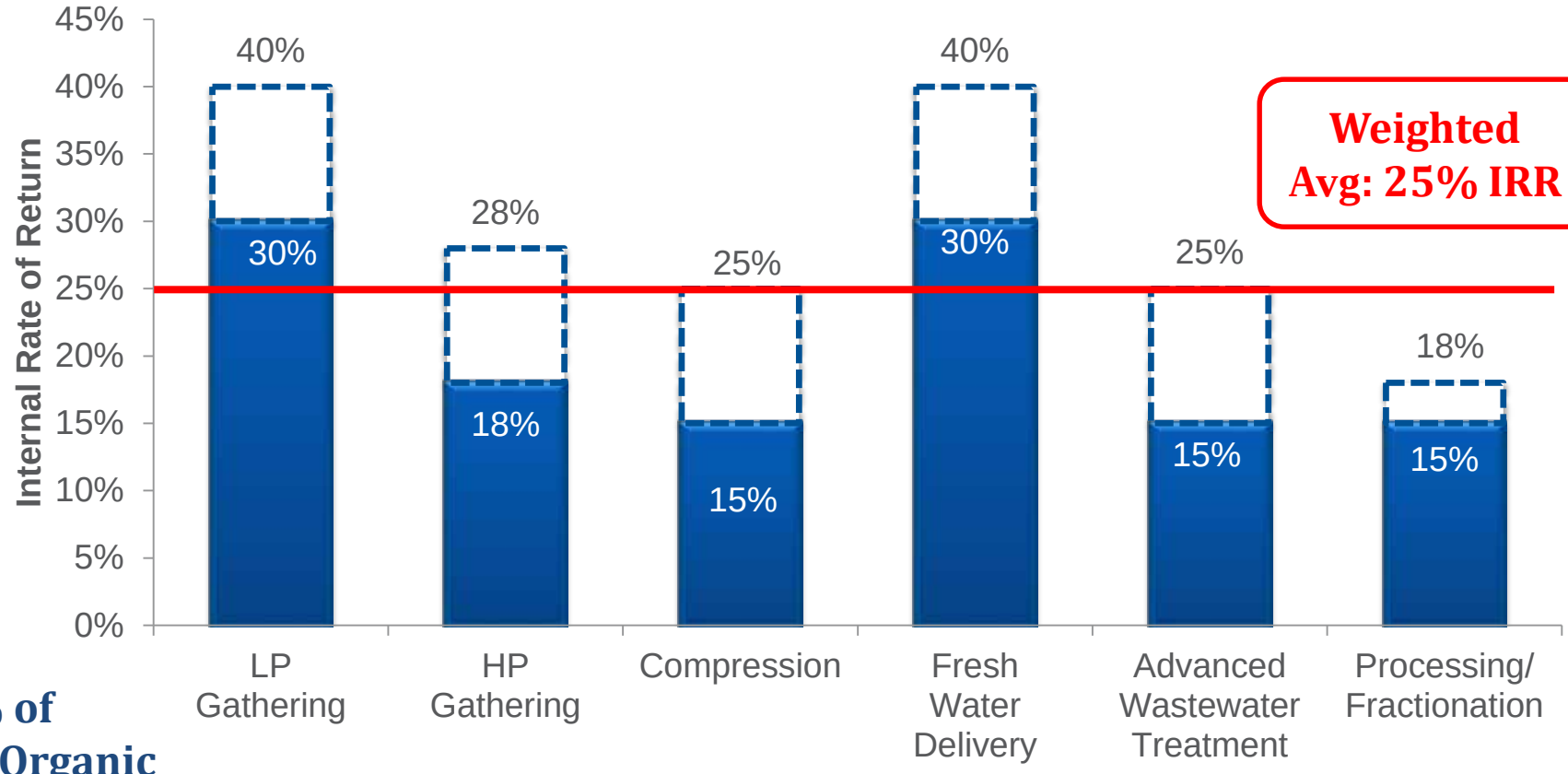
Note: Includes water earnings and capital invested on a recast basis prior to drop down and excludes drop down purchase price

Free Cash Flow is a non-GAAP measure. For additional information regarding this measure, please see "Antero Midstream Non-GAAP Measures" in the Appendix..

Antero Midstream Project Economics

"Just-in-time" capital investment philosophy drives attractive project IRR's

AM Project Economics by Investment



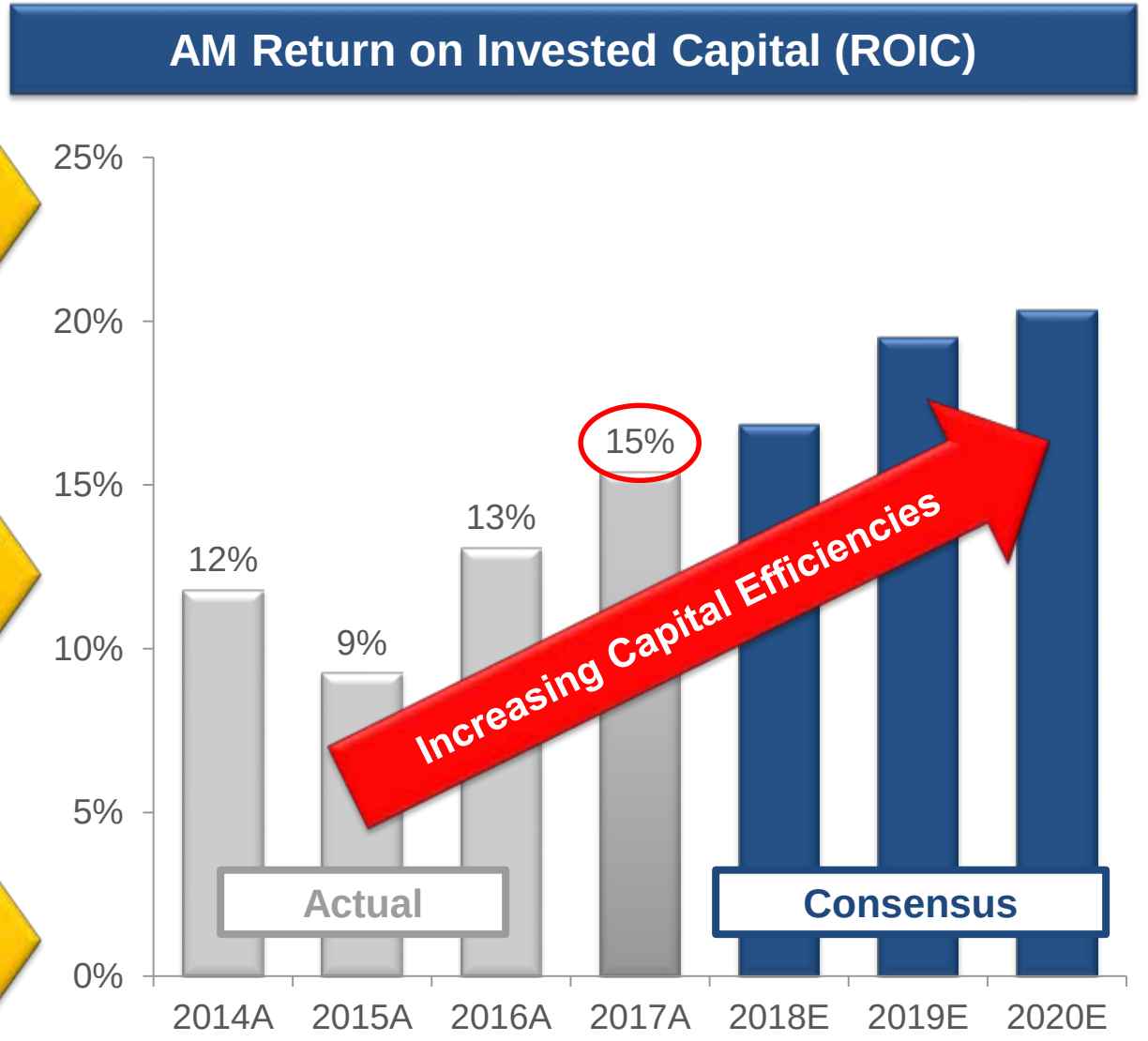
% of 5-year Organic Project Backlog	LP Gathering	HP Gathering	Compression	Fresh Water Delivery	Advanced Wastewater Treatment	Processing/ Fractionation
	17%	12%	29%	12%	-	30%

Antero Midstream Return on Invested Capital

2017 ROIC of 15% in only fourth year of AM operations

Future organic growth capital leverages existing trunklines and major gathering arteries

Fewer pads to service reduces capital with same throughput



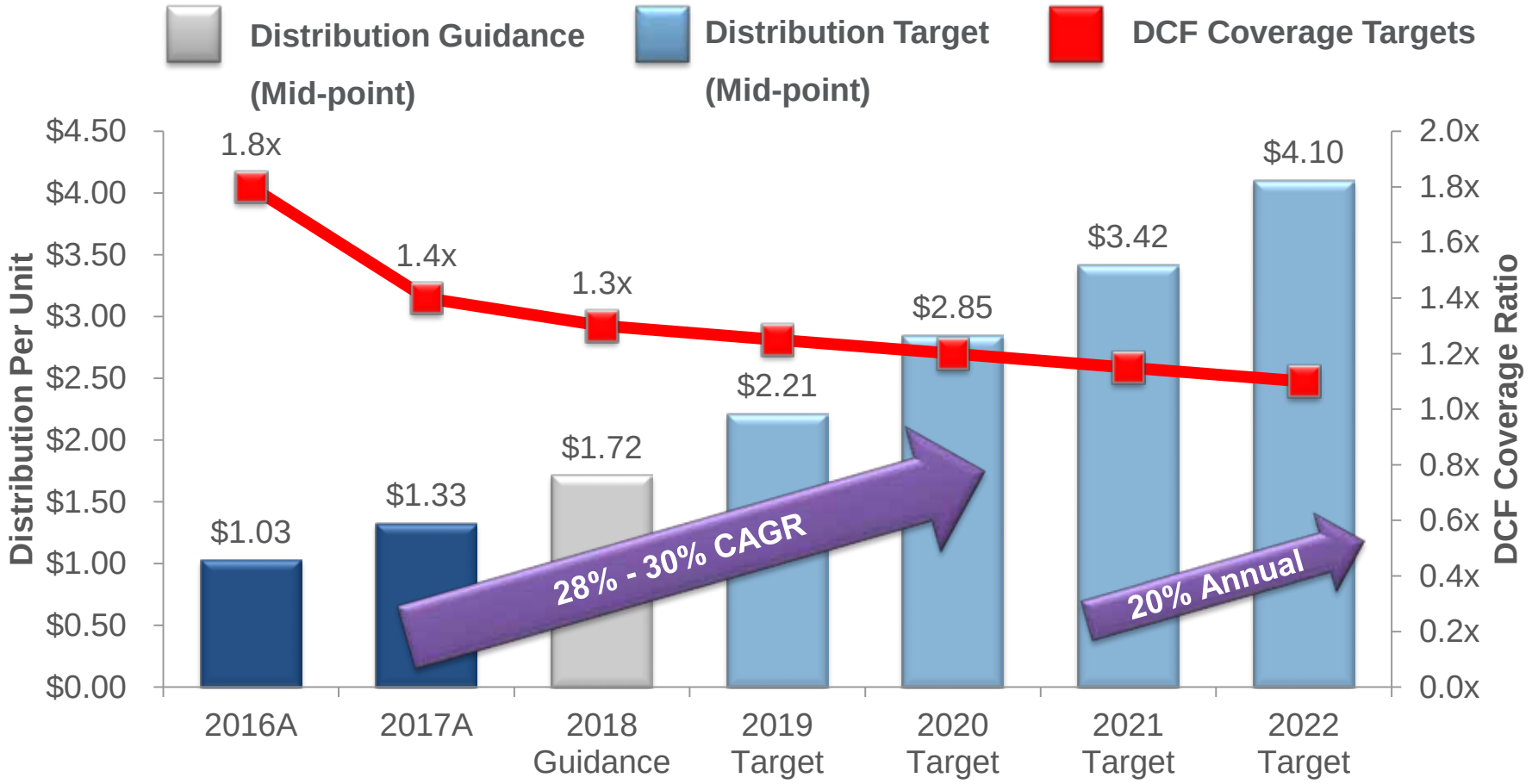
Source: Factset consensus estimates. See appendix for ROIC calculation

Return on invested capital is a non-GAAP measure. For additional information regarding this measure, please see "Antero Midstream Non-GAAP Measures" in the Appendix.

Long-Term Distribution and Coverage Targets

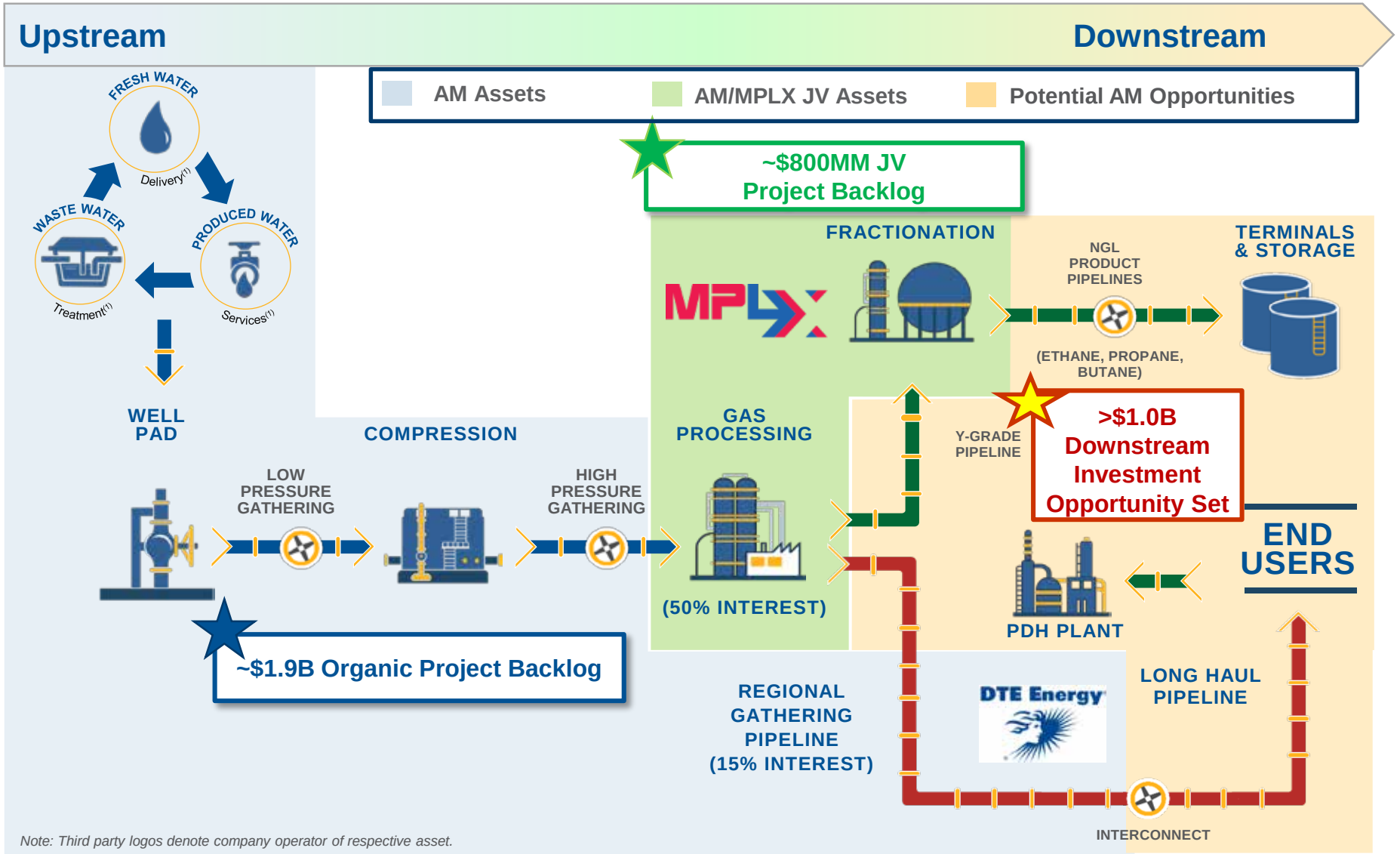
Unchanged capital investment philosophy with disciplined financial policies result in ability to target peer-leading distribution growth through 2022

Long-Term Distribution Targets and DCF Coverage



Northeast Value Chain Opportunity

5-year identified project inventory of $2.7B plus an additional $1.0B of potential downstream opportunities



Note: Third party logos denote company operator of respective asset.

Most Integrated Natural Gas & NGL Business in the U.S.

Antero Resources

53% of LP Units

Antero Midstream Partners LP

World Class E&P Operator in Appalachia

A Leading Northeast Infrastructure Platform

Contiguous Core Acreage Position Allows for Long Lateral Drilling and Significant Capital Efficiencies

Largest Exposure to NGLs Among Producers in the U.S. Leads to Peer Leading Cash Flow Margins

Optimized 5-Year Plan Results in High Return Drilling & Free Cash Flow

Midstream Ownership & Integration Delivers Value and Just-in-Time Infrastructure Buildout

Antero
Resources
Appendix
PROCOR

2018 Guidance

	Stand-Alone E&P	Consolidated
Net Daily Production (Bcfe/d)	~2.7	
Net Liquids Production (BBl/d)	~130,000	
Natural Gas Realized Price Differential to Nymex	$0.00 to $0.05 Premium	
C3+ NGL Realized Price *(% of Nymex WTI)*	62.5% – 67.5%	
Cash Production Expense ($/Mcfe)	$2.10 – $2.20	$1.65 – $1.75
Marketing Expense ($/Mcfe) (10% Mitigation Assumed)	$0.10 – $0.125	
G&A Expense ($/Mcfe) *(before equity-based compensation)*	$0.125 – $0.175	$0.15 - $0.20
Adjusted EBITDAX	$1,700 – $1,800	$2,050 – $2,150
Adjusted Operating Cash Flow	$1,480 – $1,600	$1,750 – $1,900
Net Debt / LTM Adjusted EBITDAX	Low 2x	Mid 2x
D&C Capital Expenditures ($MM)	$1,500	$1,300
Land Capital Expenditures ($MM)	$150 ($25MM Maintenance)	$150 ($25MM Maintenance)

Note: See Appendix for key definitions. Cash flow and EBITDAX guidance based on 12/31/2017 strip pricing . 2018 average NYMEX and WTI pricing was $2.83/MMBtu and $59.57/Bbl, respectively.

(1) Includes lease operating expense, gathering, compression, processing and transportation expense and production and ad valorem taxes.

Antero Guidance and Long-Term Target Assumptions

	Stand-Alone E&P	Consolidated
Net Daily Production (MMcfe/d)	20% CAGR through 2020 and 15% Growth in each of 2021 and 2022	
Natural Gas Realized Price Differential to Nymex	$0.00 to $0.05 Premium (2018) $0.00 to $0.10 Premium (2019 – 2022)	
C3+ NGL Realized Price *(% of Nymex WTI)*	62.5% – 67.5% (2018) 72% (2019+) – ME2 Fees Booked to Transport Costs	
Realized Oil Price Differential to WTI	($5.00) – ($6.00)	
Cash Production Expense ($/Mcfe)(1)	$2.10 - $2.20 (2018) $2.10 – $2.25 (2019 – 2022)	$1.65 - $1.75 (2018) $1.65 – $1.75 (2019 – 2022)
Marketing Expense ($/Mcfe)	$0.10 – $0.125 (2018) $0.15 – $0.20 (2019) <$0.10 (2020) $0.00 (2021 – 2022)	
G&A Expense ($/Mcfe) *(before equity-based compensation)*	$0.125 – $0.175 (2018 – 2019) $0.10 – $0.15 (2020 – 2022)	$0.15 - $0.20 (2018 – 2019) $0.10 – $0.15 (2020 – 2022)
Cash Interest Expense ($/Mcfe)	$0.175 – $0.225 (2018 – 2019) $0.10 – $0.15 (2020 – 2021) <$0.10 (2022)	$0.25 – $0.30 (2018 – 2019) $0.20 – $0.25 (2020 – 2022)
Well Costs ($MM / 1,000') (Assumes 12,000' completions at 2,000 lbs. per foot of proppant)	Marcellus: $0.95 MM Utica: $1.07 MM	Marcellus: $0.80 MM Utica: $0.95 MM

(1) Includes lease operating expense, gathering, compression, processing and transportation expense and production and ad valorem taxes.

Antero Guidance and Long-Term Target Assumptions (Cont.)

	Stand-Alone E&P	Consolidated
Adjusted Operating Cash Flow[1]	$10.4B (Cumulative 2018 – 2022)	N/A
Annual D&C Capital Expenditures ($MM)	$1,500 – $1,600 (2018 – 2020) $1,700 – $2,000 (2021 – 2022)	$1,300 – $1,400 (2018 – 2021) $1,600 – $1,700 (2022)
Land Maintenance Expenditures ($MM)[2]	~$200 (Cumulative 2018 – 2022)	
Free Cash Flow[1]	$1.6B (Cumulative 2018 – 2022)	N/A
Leasehold Growth Capital Expenditures ($MM)	~$300 (Cumulative 2018 – 2022)	
Number of Well Completions	790 well completions	
Marcellus EUR per 1,000' of Lateral	2.0 Bcf/1,000'; 2.5 Bcfe/1,000' (25% ethane recovery)	
Utica EUR per 1,000' of Lateral	2.0 Bcfe/1,000' (ethane rejection)	

Note: See Appendix for key definitions. Cash flow guidance is based on 12/31/2017 strip pricing. Average NYMEX pricing was $2.83/MMBtu, $2.81/MMBtu, $2.82/MMBtu, $2.85/MMBtu and $2.89/MMBtu in 2018, 2019, 2020, 2021 and 2022. Average WTI pricing was $59.57/Bbl, $56.19/Bbl, $53.76/Bbl, $52.29/Bbl and $51.67/Bbl for 2018, 2019, 2020, 2021 and 2022.

(1) Adjusted Operating Cash Flow and Free Cash Flow are non-GAAP financial measures. For additional information regarding these measures, please see the following pages ("Antero Definitions" and "Antero Non-GAAP Measures").

(2) Includes leasehold capital expenditures required to achieve targeted working interest percentage.

Antero Long-Term Target Project Assumptions

	In-Service Date
Rover Phase 2	2Q 2018 (May 1)
Mariner East 2	Mid-Year 2018
WB Xpress West	4Q 2018
WB Xpress East	4Q 2018
Mountaineer Xpress / Gulf Xpress	YE 2018

Note: Based on publicly available information.

D&C Capital Transparency

D&C Capital

($MM)

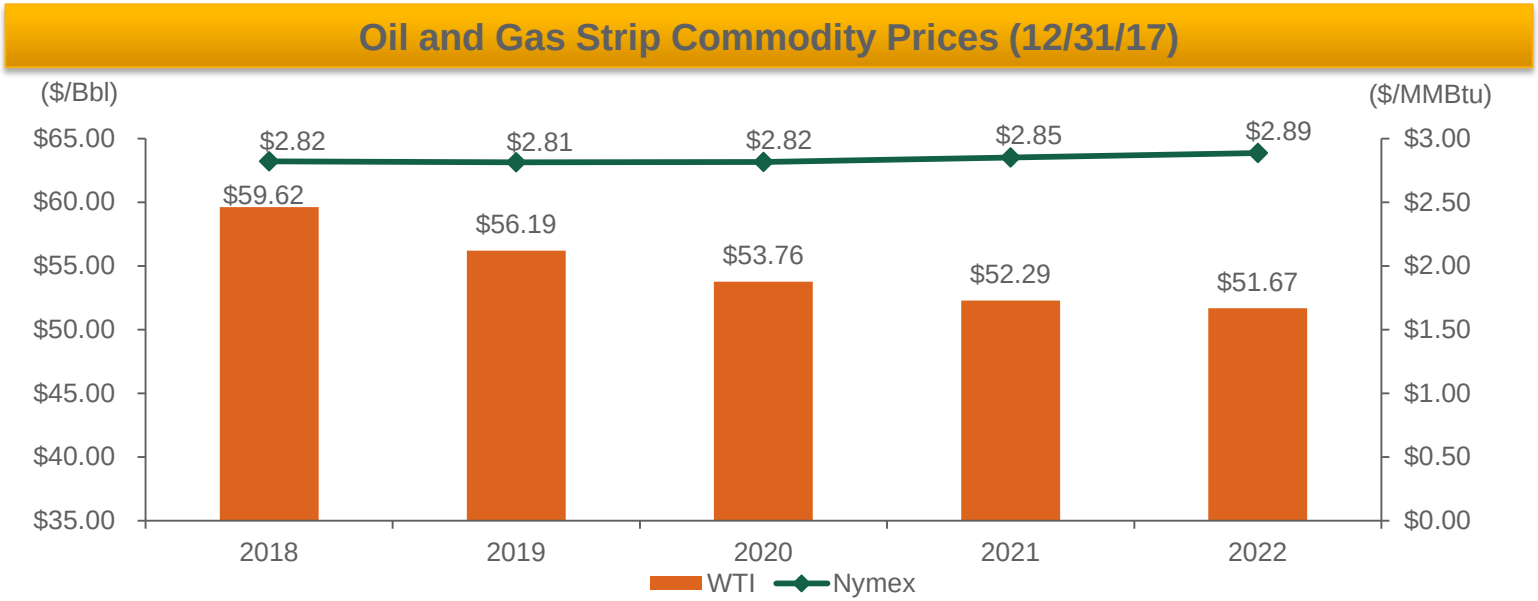
	2018	2019	2020
Total Well Completions (I.e. First Sales)	145	155	160
Average Lateral	9,700	10,500	11,600
Adjusted Well Count (I.e. Based on Capital Timing)	155	157	150
Average Lateral	9,700	10,500	11,600
Total Adjusted Lateral Feet	1,503,500	1,648,500	1,740,000
Cost per Lateral Foot ($MM/1,000) - Lateral Savings ONLY (1)	$0.86	$0.83	$0.81
Implied D&C	$1,293	$1,368	$1,409
Savings from Concurrent Ops. / Increasing Stages per Day		($24)	($79)
Adjusted Capital Cost	**$1,293**	**$1,344**	**$1,330**
Implied Cost per Lateral Foot ($MM/1,000)	*$0.86*	*$0.82*	*$0.76*

(1) Based on Marcellus AFE, which assumes inflation on consumable products (i.e. sand/chemicals).

Antero Long-Term Target Pricing Assumptions

Commodity prices: All forecasts reflect the following commodity price cases:

- Base case: Strip commodity pricing at 12/31/17 ($54.71 WTI crude oil & $2.84 Nymex Henry Hub) for 2018 - 2022
- Upside case: 12/31/17 Strip for 2018 and $60 WTI crude oil & $2.85 Nymex Henry Hub gas prices for 2019 - 2022
- Downside case: 12/31/17 Strip for 2018 $50 WTI crude oil & $2.85 Nymex Henry Hub gas prices for 2019 - 2022

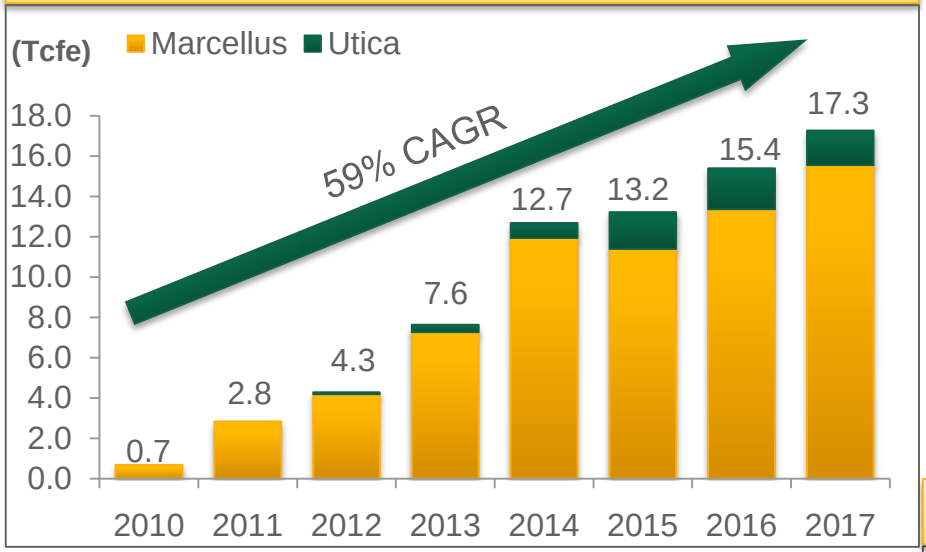


Current Hedging Arrangements

- 80% Hedged on natural gas production through 2020 at $3.44/MMBtu and 52% hedged on natural gas production through 2022 at $3.34/MMBtu
- 23% hedged on C3+ NGL production in 2018 at $0.75/gallon (Propane volume only)

Substantial Reserve Growth

NET PROVED RESERVES (Tcfe)[1]



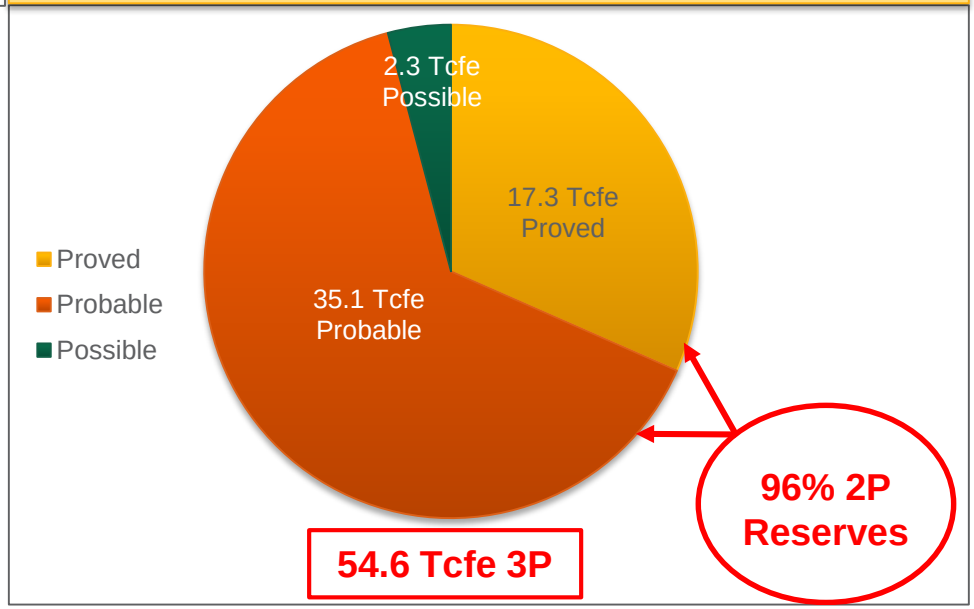
$10.8B Proved PV-10

2017 Year-End proved pre-tax PV-10 at SEC pricing, including $0.6B of hedge value

$18.4B 3P PV-10

2017 Year-End 3P pre-tax PV-10 at SEC pricing, including $0.6B of hedge value

3P RESERVES BY VOLUME – 2017[1]



1. *2012, 2013, 2014 and 2015 reserves assuming ethane rejection. In 2016, 554 MMBbls of ethane assumed recovered to meet ethane contract. In 2017, 656 MMBbls of ethane assumed recovered to meet ethane contract. 2017 SEC prices were $2.91/MMBtu for natural gas and $45.35/Bbl for oil on a weighted average Appalachian index basis. 2017 10-year average SEC prices are NYMEX $3.11/Mcf and WTI $51.03/Bbl. 2017 realized C3+ and C2+ prices including regional market differentials were $0.77/gal and $0.49/gal, respectively.*

Competitive Gathering and Compression Fee Structure

1 AR Pays Competitive Gathering & Compression Fees

- AR's gathering and compression fees paid to AM are below the Appalachian average based on extensive internal analysis of 19 publicly disclosed and undisclosed private midstream contracts

2 AR has Low or No MVCs with AM

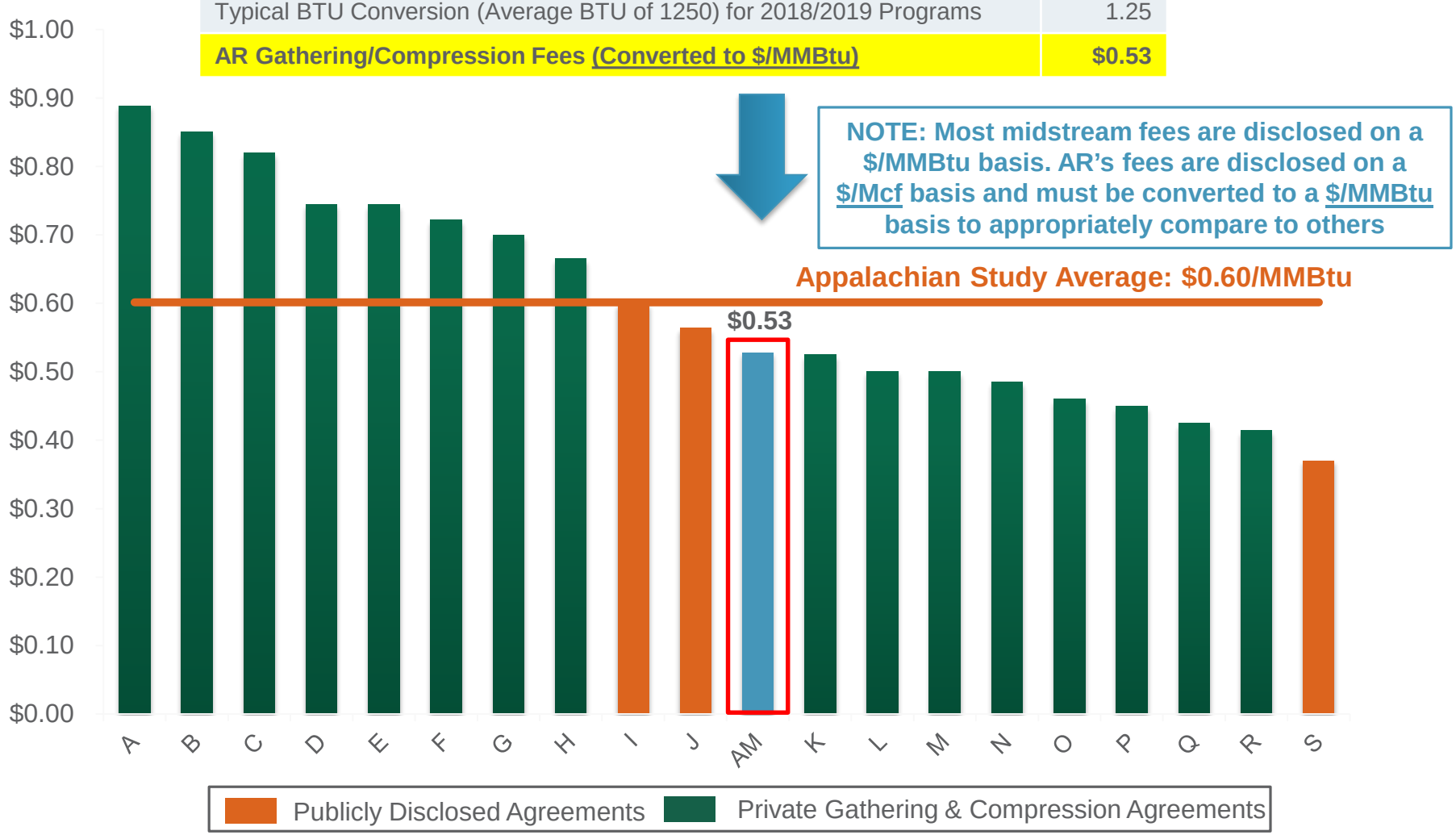
- No minimum volume commitments ("MVCs") on any low pressure gathering with AM
- MVCs on high pressure gathering and compression assets put in-service after the AM IPO (11/2014)
  - 75% to 70% MVCs on high pressure gathering and compression, respectively, when a project is requested by AR
- MVC levels are determined by AR's production forecast and capacity needs; AM may build infrastructure with capacity larger than requested for efficiency purposes that is not subject to MVCs

3 AR Receives Reliable and Timely Gathering and Compression from AM

- AR has complete visibility and drives AM's planning and in-service timing for key infrastructure projects
- AR is essentially AM's sole customer, which results in unmatched service
- AR receives just-in-time customized and controlled midstream buildout
- Critical to AR's ability to execute its development plan and optimize its capital efficiency

Appalachia Gathering and Compression Fee Study

AR Fees Paid to AM Converted to MMBtu	
AR Contracted Gathering/Compression Fees to AM **($/Mcf)**	$0.66
Typical BTU Conversion (Average BTU of 1250) for 2018/2019 Programs	1.25
AR Gathering/Compression Fees (Converted to $/MMBtu)	**$0.53**



Note: All gathering & compression fees normalized to 1,250 Btu gas and two stage compression. Analysis based on public and private company disclosures for Appalachia midstream contracts.

Competitive Fresh Water Fee Structure

1 AR Pays Highly Competitive Fresh Water Fees

- AR pays a fixed-fee per barrel to AM for fresh water pipeline service at the well pad that is firm and is $0.50/Bbl lower cost than variable sourcing and trucking costs

Peer Challenges:

- Exposure to trucking cost inflation currently observed in Appalachia, driven by continued production growth and larger completions requiring more water

2 AR has Water MVCs with AM only through 2019

- AR has very manageable MVCs on fresh water of 120 Mbbl/d in both 2018 and 2019

3 AR Receives Reliable and Timely Fresh Water Service From AM

- AR has never missed a scheduled completion date due to the inability to source and transport fresh water for completions through AM

Peer Challenges:

- Unavailability of local water sources during dry season or drought
- Logistical challenges accessing pads and rural roads by truck, particularly during inclement weather

4 Sustainable Clean Water via Pipeline

- Fresh water pipeline system eliminated >620,000 truck trips and 42,000 tons of CO2 emissions for AR in 2017 alone
- Full-cycle water system integrated with Antero Clearwater facility to reuse the fresh water by-product of the advanced wastewaster treatment

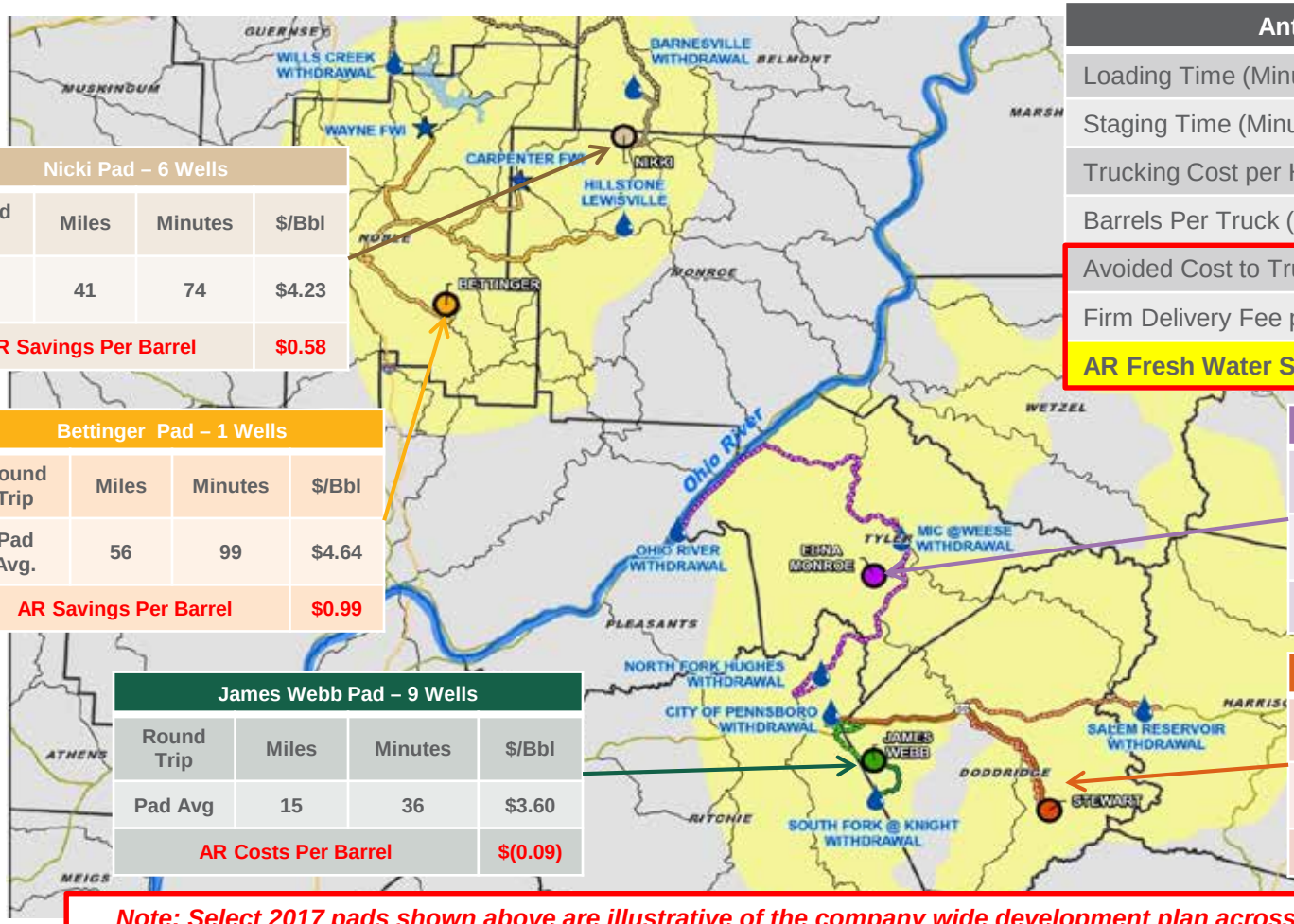
Peer Challenges:

- Utilizing produced and flowback water in completions rather than fresh water increases chemical costs during completions and increases risk of negative impact on reservoir productivity

AR Saved ~$0.50/Bbl on Fresh Water in 2017

Antero analyzed its 2017 completions and the "avoided cost" of utilizing AM's fresh water pipeline system vs. trucking water for completions

- Antero utilized mapping and routing expertise to find optimized routes to each pad (i.e. "best case" travel routes)
- Costs on a per barrel basis can vary dramatically due to hourly trucking costs (typical delays due to: staging and loading times, traffic congestion, completion shut-downs, bad weather, and challenging topography)
- AR realized savings in 2017 alone totaled $0.50/Bbl or $28 million



Antero 2017 Average	
Loading Time (Minutes)	60
Staging Time (Minutes)	120
Trucking Cost per Hour	$90
Barrels Per Truck (Bbls)	90
Avoided Cost to Truck to All Pads ($/Bbl)	$4.19
Firm Delivery Fee paid to AM ($/Bbl)	$3.69
AR Fresh Water Savings ($/Bbl)	**$0.50**

Nicki Pad – 6 Wells

Round Trip	Miles	Minutes	$/Bbl
Pad Avg.	41	74	$4.23
AR Savings Per Barrel			$0.58

Bettinger Pad – 1 Wells

Round Trip	Miles	Minutes	$/Bbl
Pad Avg.	56	99	$4.64
AR Savings Per Barrel			$0.99

James Webb Pad – 9 Wells

Round Trip	Miles	Minutes	$/Bbl
Pad Avg	15	36	$3.60
AR Costs Per Barrel			$(0.09)

Edna Monroe Pad – 10 Wells

Round Trip	Miles	Minutes	$/Bbl
Pad Avg	36	77	$4.28
AR Savings Per Barrel			$0.59

Stewart Pad – 4 Wells

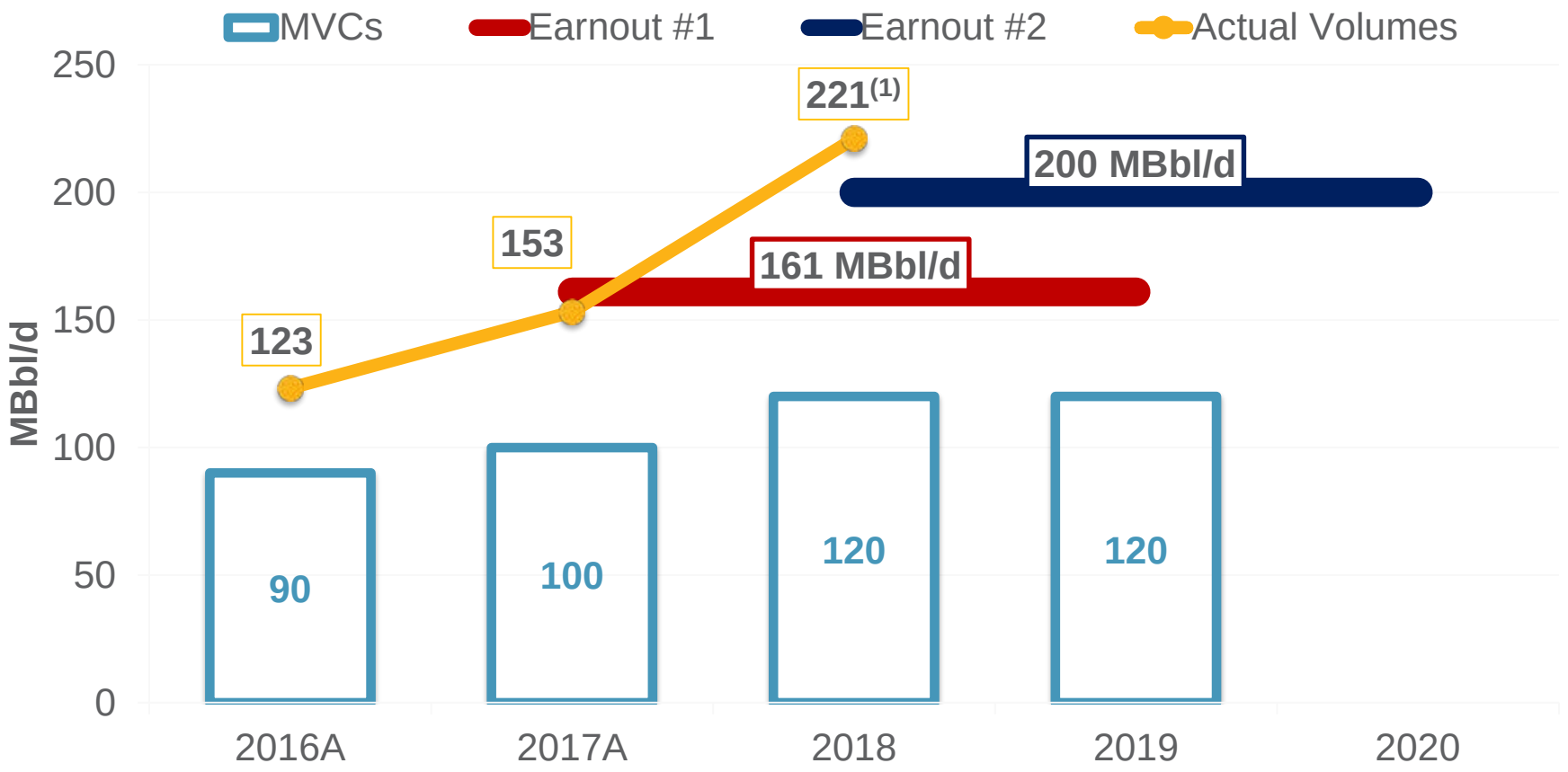
Round Trip	Miles	Minutes	$/Bbl
Pad Avg	51	83	$4.38
AR Savings Per Barrel			$0.69

Note: Select 2017 pads shown above are illustrative of the company wide development plan across AR's acreage position.

Fresh Water MVC's and Earn-Outs

- **Minimum volume commitments (MVC's) on fresh water delivery volumes were put in place to support revenues and rates of return for AM's acquisition of the water business in September 2015**
- **Earn-outs at year-end 2019 and 2020 provided incentives for AR to perform long term**

Fresh Water Delivery MVC's and Earn Out Payments (MBbl/d)



(1) Represents 1Q 2018 fresh water delivery volumes.

Guidance Summary - 2018

Guidance	2017 Guidance	2018 Guidance	Change
Net Income ($MM)	$305 - $345	$435 - $480	+41%
Adjusted EBITDA ($MM)	$520 - $560	$705 - $755	+35%
DCF ($MM)	$405 - $445	$575 - $625	+41%
Distribution Growth	28 – 30%	28 – 30%	-
DCF Coverage	1.30x – 1.45x	1.25x - 1.35x	-7%
Maintenance Capex ($MM)	$65	$65	0%
Growth Capex ($MM)	$735	$585	-20%
Total Capex ($MM)	$800	$650	-19%

Adjusted EBITDA and Distributable Cash Flow are non-GAAP measures. For additional information regarding these measures, please see "Antero Midstream Non-GAAP Measures" in the Appendix.

Core of the Core Development Programs

EUR Regime	BTU Range	2018 Well Completions	2019 Well Completions	Half Cycle Well Economics (Strip Price)	Total Undrilled Locations	Average Lateral Length
Marcellus						
Highly-Rich Gas Condensate	1275-1350	14	30	168%	447	12,500’
Highly-Rich Gas	1200-1275	106	101	74%	935	11,500’
Rich Gas	1100-1200	0	4	30%	495	11,150’
Ohio Utica						
Condensate	1250-1300	19	2	50%	206	9,950’
Rich Gas	1100-1200	3	9	29%	102	11,550’
Dry Gas	1050	3	9	37%	187	10,450’
Total[(1)]		**145**	**155**			
		Program Stats: **78% | 86%** Strip | $60 Oil ROR **1,253** BTU Average	Program Stats: **86% | 93%** Strip | $60 Oil ROR **1,248** BTU Average		High-Grade Inventory Totals: **2,372**	High-Grade Inventory Averages: **11,400’**

1) *Wells completed reflects midpoint of targeted completions per year.*

2018 Product Revenue Buildup

38%
Liquids as a Percent of Total Volume

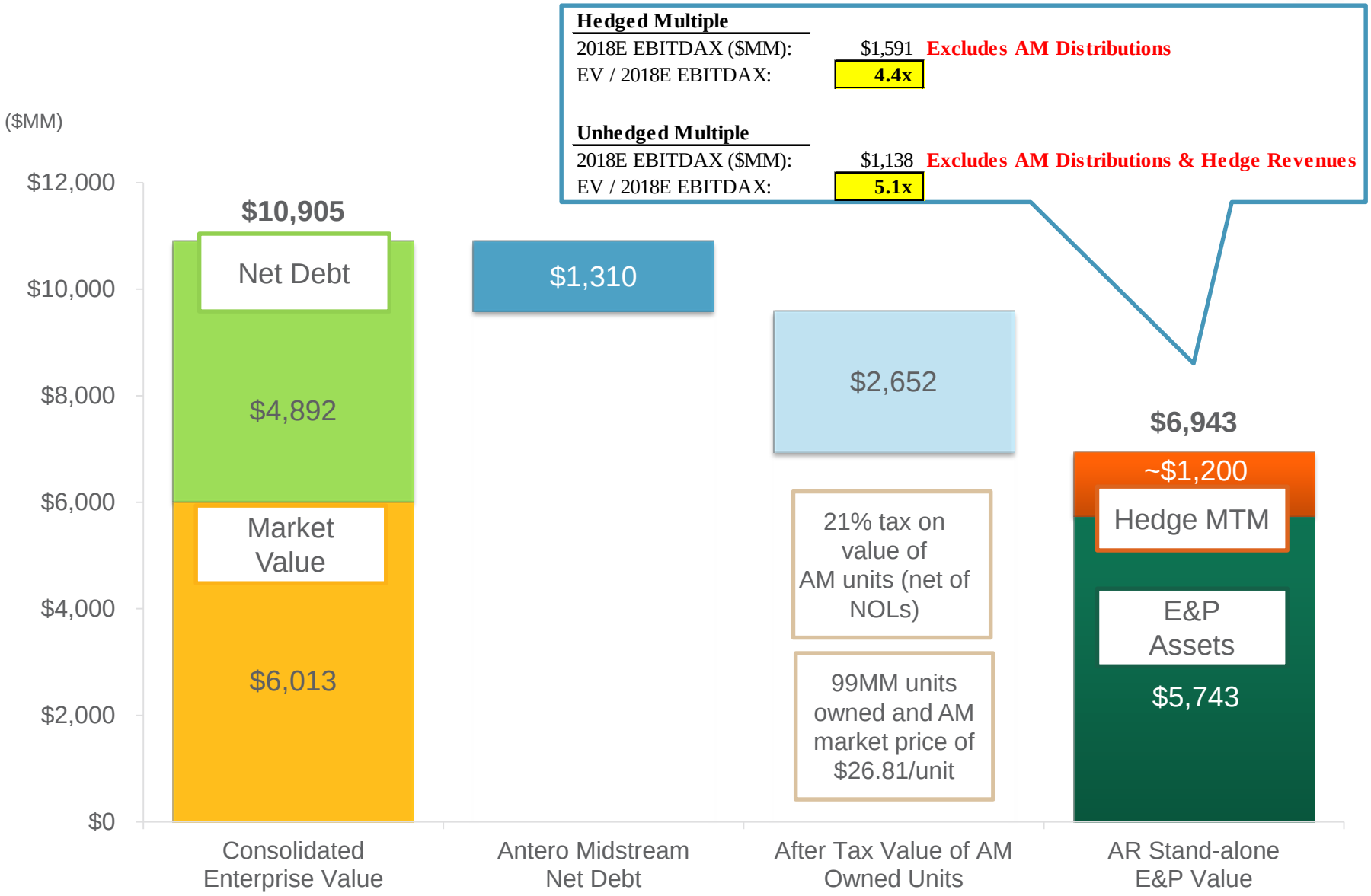
$1.5B
Liquids Revenue

43% | 38%
Pre- | Post- Hedge Liquids as Percent of Revenue

	Product	Volumes (Guidance)	Realized Price	Revenues	% of Total Revenue
Natural Gas		1,925 MMcf/d	$2.85/Mcf	$2.0B	52%
NGLs		44 MBbl/d	$10/Bbl	$0.2B	5%
NGLs		77.5 MBbl/d	$39/Bbl	$1.1B	28%
Crude		9.5 MBbl/d	$54/Bbl	$0.2B	5%
Hedges		N/A	$0.45/Mcfe	$0.4B	10%
		2,700 MMcfe/d	**$4.00/Mcfe**	**$3.9B**	**100%**

Note: See Appendix for key assumptions

Antero Consolidated and Stand-Alone Enterprise Value



Note: Data as of 3/31/18, except AR and AM unit price as of 4/30/18 and hedge mark-to-market as of 3/31/18.

Antero Assumptions: Single Well Economics

SWE Cost Type	Description of Cost	Half Cycle	Full Cycle
Well Costs	• Drilling and completion costs • Assumes well costs for a 12,000' lateral, 2,000 lbs of proppant per lateral foot and both fresh and flowback water • Utica Condensate regime assumes 1,500 lbs or proppant per lateral foot	Marcellus: $10.6MM Utica South/Dry: $12.2MM Utica Beaver: $11.5MM (60% AM water fees)	Marcellus: $11.4MM Utica South/Dry: $12.8MM Utica Beaver: $12.2MM (100% AM water fees)
Working Interest / Net Royalty Interest	• Reflects Antero's average WI/NRI in the respective plays	Marcellus: 100% / 85% Utica: 100% / 81%	
Midstream Gathering Fees	• Midstream low pressure, high pressure and compression fees	60% of AM gathering fees	100% of AM gathering fees
Firm Transportation(1)	• FT costs may include both demand and variable fees associated with expected production	Variable FT costs only of $0.06/Mcf (variable fees associated with expected production)	Fully utilized FT costs of $0.54/Mcf (including both demand and variable fees)
General & Administrative Costs	• General and administrative costs associated with Antero	None	$750,000 per well
Land	• Assumes 12,000' well with 660'/1,000' spacing for Marcellus/Utica respectively and $3,600 per acre	None	Marcellus - $655,000 per well Utica - $1,087,000 per well
Spud to FP Timing	• Provides a timeframe for initial spud to first production	184 days spud to FP	
Realized Pricing	• Commodity price assumptions	12/31 strip pricing (weighted)	

(1) SWEs exclude marketing expenses and related commodity hedge contracts that support Antero's firm transportation portfolio

Single Well Economics: Marcellus – In Ethane Rejection

Classification	Highly-Rich Gas/Condensate	Highly-Rich Gas	Rich Gas	Dry Gas
Modeled BTU	1313	1250	1150	1050
EUR (Bcfe):	32	29	26	24
EUR (MMBoe):	5.3	4.9	4.3	3.9
% Liquids:	33%	24%	11%	0%
Well Cost ($MM):	10.6	10.6	10.6	10.6
Bcfe/1,000':	2.7	2.5	2.2	2.0
Net F&D ($/Mcfe)(1):	$0.40	$0.43	$0.49	$0.53
Net Direct Operating Expense ($/Mcfe):	$1.26	$1.33	$1.39	$1.05
Transportation Expense ($/Mcfe):	$0.04	$0.05	$0.06	$0.06
Pre-Tax NPV10 ($MM):	25.5	15.9	6.9	4.7
Pre-Tax Half Cycle ROR:	168%	74%	30%	23%
Payout (Years):	1.1	1.7	3.1	4.0
Gross Core Locations in BTU Regime:	447	935	495	874

Cumulative Volumes	Highly-Rich Gas/Condensate		Highly-Rich Gas		Rich Gas		Dry Gas	
	Gas (Mmcf)	Oil (Mbbl)	Gas (Mmcf)	Oil (Mbbl)	Gas (Mmcf)	Oil (Mbbl)	Gas (Mmcf)	Oil (Mbbl)
Year 1	4,300	116	4,300	24	4,300	0	4,300	0
Year 2	6,500	143	6,500	31	6,500	0	6,500	0
Year 3	7,900	152	7,900	36	7,900	0	7,900	0
Year 4	9,100	157	9,100	40	9,100	0	9,100	0
Year 5	10,200	161	10,200	44	10,200	0	10,200	0
Year 10	13,900	176	13,900	57	13,900	0	13,900	0
Year 20	18,500	194	18,500	73	18,500	0	18,500	0

Note: SWE cost assumptions reflect average costs per Mcfe on the first five years of the life of a well.
F&D cost is defined as current D&C cost per 1,000' lateral divided by net EUR per 1,000' lateral assuming 85% NRI in Marcellus. Please see "Antero Definitions" and "Antero Non-GAAP Measures" in the Appendix.

Single Well Economics: Utica – In Ethane Rejection

Classification	Condensate	Highly-Rich Gas/ Condensate	Highly-Rich Gas	Rich Gas	Dry Gas
Modeled BTU	1275	1235	1215	1175	1050
EUR (Bcfe):	13	25	29	28	26
EUR (MMBoe):	2.2	4.2	4.8	4.6	4.4
% Liquids	40%	30%	21%	16%	0%
Well Cost ($MM):	10.8	11.5	12.2	12.2	12.2
Bcfe/1,000':	1.1	2.1	2.4	2.3	2.2
Net F&D ($/Mcfe)(1):	1.03	0.57	0.53	0.55	0.57
Net Direct Operating Expense ($/Mcfe):	1.18	1.32	1.44	1.47	0.85
Transportation Expense ($/Mcfe):	$0.04	$0.05	$0.05	$0.06	$0.07
Pre-Tax NPV10 ($MM):	7.5	16.3	11.8	8.3	9.6
Pre-Tax Half Cycle ROR:	45%	121%	54%	37%	38%
Payout (Years):	1.9	1.0	1.8	2.3	2.4
Gross Core Locations in BTU Regime:	206	27	22	102	187

Cumulative Volumes	Condensate		Highly-Rich Gas/ Condensate		Highly-Rich Gas		Rich Gas		Dry Gas	
	Gas (Mmcf)	Oil (Bbl)	Gas (Mmcf)	Oil (Bbl)	Gas (Mmcf)	Oil (Bbl)	Gas (Mmcf)	Oil (Bbl)	Gas (Mmcf)	Oil (Bbl)
Year 1	1,600	129	4,300	110	5,600	6	5,400	0	5,500	0
Year 2	2,300	153	5,800	127	7,700	8	7,500	0	8,200	0
Year 3	2,800	166	6,900	138	9,100	9	8,800	0	10,000	0
Year 4	3,300	176	7,700	146	10,200	10	9,900	0	11,400	0
Year 5	3,600	186	8,400	152	11,100	11	10,800	0	12,500	0
Year 10	5,000	219	10,900	175	14,500	14	14,100	0	16,500	0
Year 20	6,700	258	14,000	202	18,700	19	18,200	0	21,200	0

Note: SWE cost assumptions reflect average costs per Mcfe on the first five years of the life of a well.
F&D cost is defined as current D&C cost per 1,000' lateral divided by net EUR per 1,000' lateral assuming 81% NRI in Utica. Please see "Antero Definitions" and "Antero Non-GAAP Measures" in the Appendix.

Antero Non-GAAP Measures

Consolidated Adjusted EBITDAX, Stand-alone E&P Adjusted EBITDAX, Consolidated Adjusted Operating Cash Flow, Stand-alone E&P Adjusted Operating Cash Flow and Free Cash Flow are financial measures that are not calculated in accordance with U.S. generally accepted accounting principles ("GAAP"). The non-GAAP financial measures used by the company may not be comparable to similarly titled measures utilized by other companies. These measures should not be considered in isolation or as substitutes for their nearest GAAP measures. The Stand-alone measures are presented to isolate the results of the operations of Antero apart from the performance of Antero Midstream, which is otherwise consolidated into the results of Antero.

Consolidated Adjusted EBITDAX and Stand-alone E&P Adjusted EBITDAX

The GAAP financial measure nearest to Consolidated Adjusted EBITDAX is net income or loss including noncontrolling interest that will be reported in Antero's consolidated financial statements. The GAAP financial measure nearest to Stand-alone E&P Adjusted EBITDAX is Stand-alone net income or loss that will be reported in the Parent column of Antero's guarantor footnote to its financial statements. While there are limitations associated with the use of Consolidated Adjusted EBITDAX and Stand-alone E&P Adjusted EBITDAX described below, management believes that these measures are useful to an investor in evaluating the company's financial performance because these measures:

- are 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 (both on a consolidated and Stand-alone basis) 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 (both on a consolidated and Stand-alone basis), in presentations to the company's board of directors, and as a basis for strategic planning and forecasting. Consolidated Adjusted EBITDAX is also used by the board of directors as a performance measure in determining executive compensation. Consolidated Adjusted EBITDAX, as defined by our credit facility, is used by our lenders pursuant to covenants under our revolving credit facility and the indentures governing the company's senior notes.

There are significant limitations to using Consolidated Adjusted EBITDAX and Stand-alone E&P Adjusted EBITDAX 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 on a consolidated and Stand-alone basis, 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, Consolidated Adjusted EBITDAX and Stand-alone E&P Adjusted EBITDAX provide no information regarding a company's capital structure, borrowings, interest costs, capital expenditures, and working capital movement or tax position.

Antero Non-GAAP Measures

Antero has not included a reconciliation of Consolidated Adjusted EBITDAX or Stand-alone E&P Adjusted EBITDAX to their nearest GAAP financial measures for 2018 because it cannot do so without unreasonable effort and any attempt to do so would be inherently imprecise. Antero is able to forecast the following reconciling items between Consolidated Adjusted EBITDAX and Stand-alone E&P Adjusted EBITDAX to net income from continuing operations including noncontrolling interest:

(in thousands)	Consolidated		Stand-alone E&P	
	Low	High	Low	High
Interest expense	$250,000	$300,000	$200,000	$220,000
Depreciation, depletion, amortization, and accretion expense	950,000	1,050,000	800,000	900,000
Impairment expense	100,000	125,000	100,000	125,000
Exploration expense	5,000	15,000	5,000	15,000
Equity-based compensation expense	95,000	115,000	70,000	90,000
Equity in earnings of unconsolidated affiliate	30,000	40,000	N/A	N/A
Distributions from unconsolidated affiliates	40,000	50,000	N/A	N/A
Distributions from limited partner interest in Antero Midstream	N/A	N/A	166,000	170,000

Antero has a significant portfolio of commodity derivative contracts that it does not account for using hedge accounting, and forecasting unrealized gains or losses on this portfolio is impracticable and imprecise due to the price volatility of the underlying commodities. Antero is also forecasting no impact from franchise taxes, gain or loss on early extinguishment of debt, or gain or loss on sale of assets, for 2018. For income tax expense (benefit), Antero is forecasting a 2018 effective tax rate of 18% to 19%.

Antero Non-GAAP Measures

Consolidated Adjusted Operating Cash Flow, Stand-alone E&P Adjusted Operating Cash Flow and Free Cash Flow

The GAAP financial measure nearest to Consolidated Adjusted Operating Cash Flow is cash flow from operating activities as reported in Antero's consolidated financial statements. The GAAP financial measure nearest to Stand-alone E&P Adjusted Operating Cash Flow and Free Cash Flow is Stand-alone cash flow from operating activities that will be reported in the Parent column of Antero's guarantor footnote to its financial statements. Management believes that Consolidated Adjusted Operating Cash Flow and Stand-alone E&P Adjusted Operating Cash Flow are useful indicators of the company's ability to internally fund its activities and to service or incur additional debt on a consolidated and Stand-alone basis. Management believes that changes in current assets and liabilities, which are excluded from the calculation of these measures, relate to the timing of cash receipts and disbursements and therefore may not relate to the period in which the operating activities occurred and generally do not have a material impact on the ability of the company to fund its operations. Management believes that Free Cash Flow is a useful measure for assessing the company's financial performance and measuring its ability to generate excess cash from its operations.

There are significant limitations to using Consolidated Adjusted Operating Cash Flow, Stand-alone E&P Adjusted Operating Cash Flow 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 on a consolidated and Stand-alone E&P basis, the lack of comparability of results of operations of different companies and the different methods of calculating Consolidated Adjusted Operating Cash Flow and Stand-alone E&P Adjusted Operating Cash Flow reported by different companies. Consolidated Adjusted Operating Cash Flow and Stand-alone E&P Adjusted Operating Cash Flow do not represent funds available for discretionary use because those funds may be required for debt service, capital expenditures, working capital, income taxes, franchise taxes, exploration expenses, and other commitments and obligations.

Antero has not included reconciliations of Consolidated Adjusted Operating Cash Flow, Stand-alone E&P Adjusted Operating Cash Flow and Free Cash Flow to their nearest GAAP financial measures for 2018 because it would be impractical to forecast changes in current assets and liabilities. However, Antero is able to forecast the earn out payments expected from Antero Midstream associated with the water drop down transaction that occurred in 2015, each of which is a reconciling item between Stand-alone E&P Adjusted Operating Cash Flow and Free Cash Flow, as applicable, and cash flow from operating activities as reported in the Parent column of Antero's guarantor footnote to its financial statements. Antero forecasts these items to be $125 million in each of 2019 and 2020. Additionally, Antero is able to forecast lease maintenance expenditures and Stand-alone drilling and completion capital, each of which is a reconciling item between Free Cash Flow and its most comparable GAAP financial measure. For the 2018 to 2022 period, Antero forecasts cumulative lease maintenance expenditures of $200 million and cumulative Stand-alone E&P drilling and completion capital of $8.6 billion.

AR Stand-Alone E&P Adjusted EBITDAX Reconciliation

($ in thousands)	Three Months Ended 3/31/2018	LTM Ended 3/31/2018
Net income including noncontrolling interest	$14,833	$361,507
Commodity derivative gains	(22,437)	(241,945)
Gains on settled commodity derivatives	101,341	270,432
Marketing derivative gains	(94,234)	(72,840)
Gains on settled marketing derivatives	110,042	110,042
Interest expense	53,498	227,826
Loss on early extinguishment of debt	—	1,205
Income tax expense (benefit)	9,120	(417,277)
Depreciation, depletion, amortization, and accretion	196,468	728,296
Impairment of unproved properties	50,536	183,235
Exploration expense	1,885	8,316
Gain on change in fair value of contingent acquisition consideration	(3,874)	(13,824)
Equity-based compensation expense	14,945	71,890
Distributions from Antero Midstream	36,088	137,202
Equity in net income of Antero Midstream	20,128	57,538
Total Adjusted EBITDAX	**$488,339**	**$1,411,603**

Consolidated Adjusted EBITDAX Reconciliation

($ in thousands)	Three Months Ended 3/31/2018	LTM Ended 3/31/2018
Net income (loss) including noncontrolling interest	$80,810	$560,389
Commodity derivative gains	(22,437)	(241,945)
Gains on settled commodity derivatives	101,341	270,432
Marketing derivative gains	(94,234)	(72,840)
Gains on settled marketing derivatives	110,042	110,042
Interest expense	64,426	266,457
Loss on early extinguishment of debt	—	1,500
Income tax expense (benefit)	9,120	(417,277)
Depreciation, depletion, amortization, and accretion	228,934	852,788
Impairment of unproved properties	50,536	183,235
Impairment of gathering systems and facilities	—	23,431
Exploration expense	1,885	8,316
Equity-based compensation expense	21,156	99,098
Equity in loss (earnings) of unconsolidated affiliate	(7,862)	(25,825)
Distributions from unconsolidated affiliate	7,085	27,280
Total Adjusted EBITDAX	**$550,802**	**$1,645,081**

Antero Midstream Non-GAAP Measures

Non-GAAP Financial Measures and Definitions

Antero Midstream views Adjusted EBITDA as an important indicator of the Partnership's performance. Antero Midstream defines Adjusted EBITDA as Net Income before interest expense, depreciation expense, impairment expense, accretion of contingent acquisition consideration, equity-based compensation expense, excluding equity in earnings of unconsolidated affiliates and including cash distributions from unconsolidated affiliates.

Antero Midstream uses Adjusted EBITDA to assess:

- the financial performance of the Partnership's assets, without regard to financing methods in the case of Adjusted EBITDA, capital structure or historical cost basis;
- its operating performance and return on capital as compared to other publicly traded partnerships in the midstream energy sector, without regard to financing or capital structure; and
- the viability of acquisitions and other capital expenditure projects.

The Partnership defines Distributable Cash Flow as Adjusted EBITDA less interest paid, income tax withholding payments and cash reserved for payments of income tax withholding upon vesting of equity-based compensation awards, cash reserved for bond interest and ongoing maintenance capital expenditures paid. Antero Midstream uses Distributable Cash Flow as a performance metric to compare the cash generating performance of the Partnership from period to period and to compare the cash generating performance for specific periods to the cash distributions (if any) that are expected to be paid to unitholders. Distributable Cash Flow does not reflect changes in working capital balances.

The Partnership defines Free Cash Flow as cash flow from operating activities before changes in working capital less capital expenditures. Management believes that Free Cash Flow is a useful indicator of the Partnership's ability to internally fund infrastructure investments, service or incur additional debt, and assess the company's financial performance and its ability to generate excess cash from its operations. Management believes that changes in operating assets and liabilities relate to the timing of cash receipts and disbursements and therefore may not relate to the period in which the operating activities occurred.

The Partnership defines Return on Invested Capital as net income plus interest expense divided by average total liabilities and partners' capital, excluding current liabilities. Management believes that Return on Invested Capital is a useful indicator of the Partnership's return on its infrastructure investments.

The Partnership defines Adjusted Operating Cash Flow as net cash provided by operating activities before changes in current assets and liabilities. See "Non-GAAP Measures" for additional detail.

Antero Midstream Non-GAAP Measures

The GAAP financial measure nearest to Adjusted Operating Cash Flow is cash flow from operating activities as reported in Antero Midstream's consolidated financial statements. Management believes that Adjusted Operating Cash Flow is a useful indicator of the company's ability to internally fund its activities and to service or incur additional debt. Management believes that changes in current assets and liabilities, which are excluded from the calculation of these measures, relate to the timing of cash receipts and disbursements and therefore may not relate to the period in which the operating activities occurred and generally do not have a material impact on the ability of the company to fund its operations. Management believes that Free Cash Flow is a useful measure for assessing the company's financial performance and measuring its ability to generate excess cash from its operations.

There are significant limitations to using Adjusted Operating Cash Flow 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 Operating Cash Flow reported by different companies. Adjusted Operating Cash Flow does not represent funds available for discretionary use because those funds may be required for debt service, capital expenditures, working capital, income taxes, and other commitments and obligations.

Antero Midstream has not included reconciliations of Adjusted Operating Cash Flow and Free Cash Flow to their nearest GAAP financial measures for 2018 because it would be impractical to forecast changes in current assets and liabilities. Antero Midstream is able to forecast capital expenditures, which is a reconciling item between Free Cash Flow and its most comparable GAAP financial measure. For the 2018 to 2022 period, Antero forecasts cumulative capital expenditures of $2.7 billion.

Antero Resources non-GAAP measures and definitions are included in the Antero Resources analyst day presentation, which can be found on www.anteroresources.com.

Antero Midstream Non-GAAP Measures

Adjusted EBITDA and Distributable Cash Flow are non-GAAP financial measures. The GAAP measure most directly comparable to Adjusted EBITDA and Distributable Cash Flow is Net Income. The non-GAAP financial measures of Adjusted EBITDA and Distributable Cash Flow should not be considered as alternatives to the GAAP measure of Net Income. Adjusted EBITDA and Distributable Cash Flow are not presentations made in accordance with GAAP and have important limitations as an analytical tool because they include some, but not all, items that affect Net Income and Adjusted EBITDA. You should not consider Adjusted EBITDA and Distributable Cash Flow in isolation or as a substitute for analyses of results as reported under GAAP. Antero Midstream's definition of Adjusted EBITDA and Distributable Cash Flow may not be comparable to similarly titled measures of other partnerships .

Antero Midstream has not included a reconciliation of Adjusted EBITDA to the nearest GAAP financial measure for 2018 because it cannot do so without unreasonable effort and any attempt to do so would be inherently imprecise. Antero Midstream is able to forecast the following reconciling items between Adjusted EBITDA and net income (in thousands):

	Twelve months ended December 31, 2018		
	Low		High
Depreciation expense	$ 160,000	—	$ 170,000
Equity based compensation expense	25,000	—	35,000
Accretion of contingent acquisition consideration	15,000	—	20,000
Equity in earnings of unconsolidated affiliates	30,000	—	40,000
Distributions from unconsolidated affiliates	40,000	—	50,000

The Partnership cannot forecast interest expense due to the timing and uncertainty of debt issuances and associated interest rates. Additionally, Antero Midstream cannot reasonably forecast impairment expense as the impairment is driven by a number of factors that will be determined in the future and are beyond Antero Midstream's control currently.

Adjusted EBITDA and DCF Reconciliation ($ in thousands)

	Three months ended March 31,	
	2017	2018
Net income	**$ 75,091**	**$ 108,105**
Interest expense	8,836	11,297
Depreciation expense	27,536	32,432
Accretion of contingent acquisition consideration	3,526	3,874
Accretion of asset retirement obligations	—	34
Equity-based compensation	6,286	6,211
Equity in earnings of unconsolidated affiliates	(2,231)	(7,862)
Distributions from unconsolidated affiliates	—	7,085
Adjusted EBITDA	**119,044**	**161,176**
Interest paid	(19,668)	(22,348)
Decrease in cash reserved for bond interest [(1)]	8,929	8,734
Income tax withholding upon vesting of Antero Midstream Partners LP equity-based compensation awards[(2)]	(1,500)	(1,500)
Maintenance capital expenditures[(3)]	(15,903)	(16,488)
Distributable Cash Flow	**$ 90,902**	**$ 129,574**
Distributions Declared to Antero Midstream Holders		
Limited Partners	55,753	72,923
Incentive distribution rights	11,553	28,453
Total Aggregate Distributions	**$ 67,306**	**$ 101,376**
DCF coverage ratio	**1.35x**	**1.28x**

Cash reserved for bond interest expense on Antero Midstream's 5.375% senior notes outstanding during the period that is paid on a semi-annual basis on March 15th and September 15th of each year.
Estimate of current period portion of expected cash payment for income tax withholding attributable to vesting of Midstream LTIP equity-based compensation awards to be paid in the fourth quarter.
Maintenance capital expenditures represent the portion of our estimated capital expenditures associated with (i) the connection of new wells to our gathering and processing systems that we believe will be necessary to offset the natural production declines Antero Resources will experience on all of its wells over time, and (ii) water delivery to new wells necessary to maintain the average throughput volume on our systems.

Regarding Hydrocarbon Quantities

The SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserve estimates (collectively, "3P"). Antero has provided internally generated estimates for proved, probable and possible reserves in this presentation in accordance with SEC guidelines and definitions. The estimates of proved, probable and possible reserves as of December 31, 2017 included in this presentation have been audited by Antero's third-party engineers. Unless otherwise noted, reserve estimates as of December 31, 2017 assume ethane rejection and strip pricing.

Actual quantities that may be ultimately recovered from Antero's interests may differ substantially from the estimates in this presentation. Factors affecting ultimate recovery include the scope of Antero's ongoing drilling program, which will be directly affected by commodity prices, the availability of capital, drilling and production costs, availability of drilling services and equipment, drilling results, lease expirations, transportation constraints, regulatory approvals and other factors; and actual drilling results, including geological and mechanical factors affecting recovery rates.

In this presentation:

- "3P reserves" refer to Antero's estimated aggregate proved, probable and possible reserves as of December 31, 2016. The SEC prohibits companies from aggregating proved, probable and possible reserves in filings with the SEC due to the different levels of certainty associated with each reserve category.
- "EUR," or "Estimated Ultimate Recovery," refers to Antero's internal estimates of per well hydrocarbon quantities that may be potentially recovered from a hypothetical future well completed as a producer in the area. These quantities do not necessarily constitute or represent reserves within the meaning of the Society of Petroleum Engineer's Petroleum Resource Management System or the SEC's oil and natural gas disclosure rules.
- "Condensate" refers to gas having a heat content between 1250 BTU and 1300 BTU in the Utica Shale.
- "Highly-Rich Gas/Condensate" refers to gas having a heat content between 1275 BTU and 1350 BTU in the Marcellus Shale and 1225 BTU and 1250 BTU in the Utica Shale.
- "Highly-Rich Gas" refers to gas having a heat content between 1200 BTU and 1275 BTU in the Marcellus Shale and 1200 BTU and 1225 BTU in the Utica Shale.
- "Rich Gas" refers to gas having a heat content of between 1100 BTU and 1200 BTU.
- "Dry Gas" refers to gas containing insufficient quantities of hydrocarbons heavier than methane to allow their commercial extraction or to require their removal in order to render the gas suitable for fuel use.