Barclays CEO Energy/Power Conference
September 6, 2016

FORWARD-LOOKING STATEMENTS

This presentation contains 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 statements, other than statements of historical facts, included in this presentation that address activities, events or developments that Antero Resources Corporation and its subsidiaries (collectively, the “Company” or “Antero”) expects, believes or anticipates will or may occur in the future are forward-looking statements. The words “believe,” “expect,” “anticipate,” “plan,” “intend,” “estimate,” “project,” “foresee,” “should,” “would,” “could,” or other similar expressions are intended to identify forward-looking statements. However, the absence of these words does not mean that the statements are not forward-looking. Without limiting the generality of the foregoing, forward-looking statements contained in this presentation specifically include estimates of the Company’s reserves, expectations of plans, strategies, objectives and anticipated financial and operating results of the Company, including as to the Company’s drilling program, production, hedging activities, capital expenditure levels and other guidance included in this presentation. These statements are based on certain assumptions made by the Company based on management’s experience and perception of historical trends, current conditions, anticipated future developments and other factors believed to be appropriate. Such statements are subject to a number of assumptions, risks and uncertainties, many of which are beyond the control of the Company, which may cause actual results to differ materially from those implied or expressed by the forward-looking statements. These include the factors discussed or referenced under the heading “Item 1A. Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2015 and in the Company’s subsequent filings with the SEC.

The Company 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 our control, incident to the exploration for and development, production, gathering and sale of natural gas 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 “Risk Factors” in our Annual Report on Form 10-K for the year ended December 31, 2015 and in the Company’s subsequent filings with the SEC.

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.

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

NEW GUIDANCE

Antero Resources	Revised 9/6/2016	Previous
Total net production (MMcfe/d)	1,800	1,750
Net natural gas production (MMcf/d)	1,365	1,355
Net liquids production (Bbl/d)	73,000	66,000
Net Daily C3+ NGL Production (Bbl/d)	53,500	52,500
Net Daily Ethane Production (Bbl/d)	15,000	10,000
Net Daily Oil Production (Bbl/d)	4,500	3,500
Cash production expense ($/Mcfe) (1)	$1.40 – $1.50	$1.50 – $1.60
Marketing expense, net ($/Mcfe)	$0.15 – $0.20	$0.15 – $0.20
G&A ($/Mcfe)	$0.20 – $0.22	$0.20 – $0.25
Natural gas realized price premium to Nymex before hedging($/Mcf)(2)(3)	$0.00 – $0.05	$0.00 – $0.10
Natural gas liquids realized price (% of WTI)	35% – 40%	35% – 40%
Oil realized price differential to NYMEX before hedging ($/Bbl)	$(10.00) – $(11.00)	$(10.00) – $(11.00)
2017 Net Production Target (MMcfe/d)	2,160 – 2,250	2,100 – 2,190
2016 Capital Budget Comparison		
Drilling & completion ($MM)	$1,300	$1,300
Land ($MM)	$100	$100
Total	$1,400	$1,400
Operated wells completed	110	110
Average drilling rigs	7	7

Antero Midstream Partners LP	Revised 9/6/2016	Previous
Net Income ($MM)	$205 – $225	$165 – $190
Adjusted EBITDA ($MM)	$365 – $385	$325 – $350
Distributable Cash Flow ($MM)	$315 – $335	$275 – $300
Year over Year Distribution Growth	30%	30%
2016 DCF Coverage Ratio	1.55x – 1.65x	>1.40x – 1.50x
Capital Expenditures ($MM)	$480	$480

1. *Includes lease operating expenses, gathering, compression, transportation expenses and production taxes.*
2. *Based on strip pricing as of August 31, 2016.*
3. *Includes Btu upgrade as Antero's processed tailgate and unprocessed dry gas production is greater than 1000 Btu on average.*

WHY OWN ANTERO?

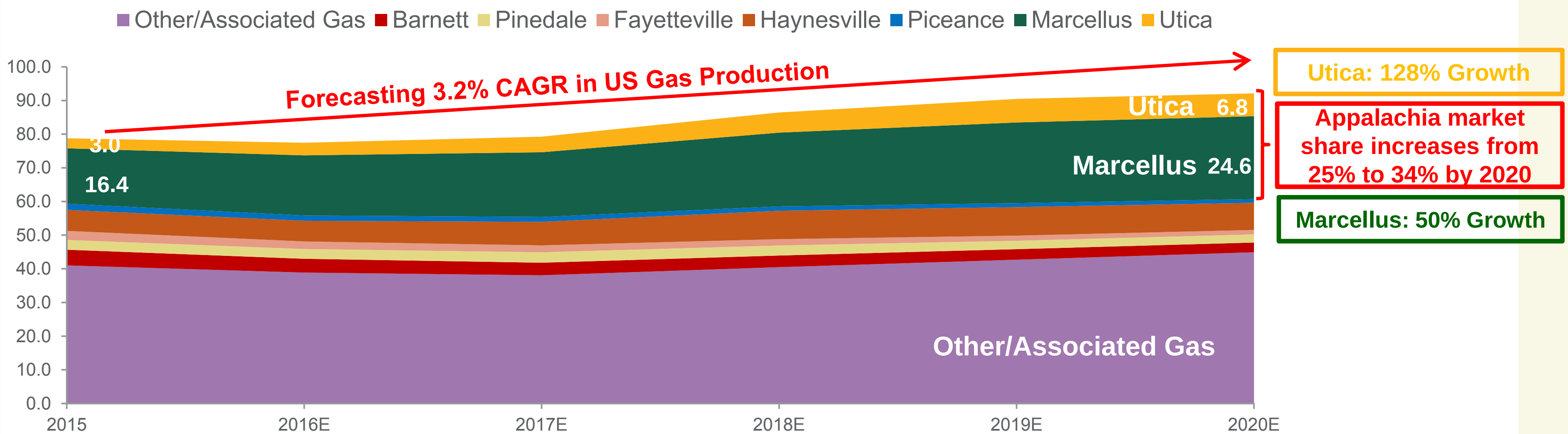
Momentum + Growth	▪ Revised production growth guidance for 2016 to 20% or 1.8 Bcfe/d ▪ 20% to 25% growth target for 2017 or 2.16 to 2.25 Bcfe/d ▪ 6 rigs currently running, 70 DUCs at YE 2016
Production Sold Forward at Premium Prices	▪ 94% of forecasted production hedged through 2018 at $3.81/MMBtu, a $0.78 premium to strip ▪ $2.1 billion mark-to-market on 3.4 Tcfe hedge position as of 6/30/2016 ▪ Over 38 Tcfe of unhedged 3P inventory to drill and produce as prices improve(1)
Balance Sheet Strength	▪ $3.9 billion of consolidated liquidity available (6/30/2016) ▪ Ba2/BB corporate ratings affirmed; $4.5 billion AR borrowing base affirmed ▪ 3.3x consolidated net debt/EBITDAX (6/30/2016)
Superior Realized Prices & Margins	▪ Realized prices and EBITDAX margins lead Appalachian peers by a wide margin ▪ Forecast positive basis to Nymex in 2016 and beyond due to large FT portfolio with superior pricing points; low average cost of $0.46 per MMBtu
Attractive & Improving Well Economics	▪ 51% to 77% ROR at 6/30/2016 strip prices assuming 2.0 Bcf/1,000' EURs in high grade liquids-rich Marcellus; 49% to 62% ROR for Utica wells ▪ Long laterals up to 14,000 ft.; rolling off legacy drilling and completion contracts; multiple process improvements and higher proppant loading all improving RORs
Largest Core Drilling Inventory	▪ Largest core drilling inventory in the Marcellus/Utica with over 4,300 undrilled core locations including 1,600 high-graded core locations, pro forma for the pending acquisition ▪ Antero continues to be a leading consolidator

1. Pro forma for pending acreage acquisition announced 6/9/2016.

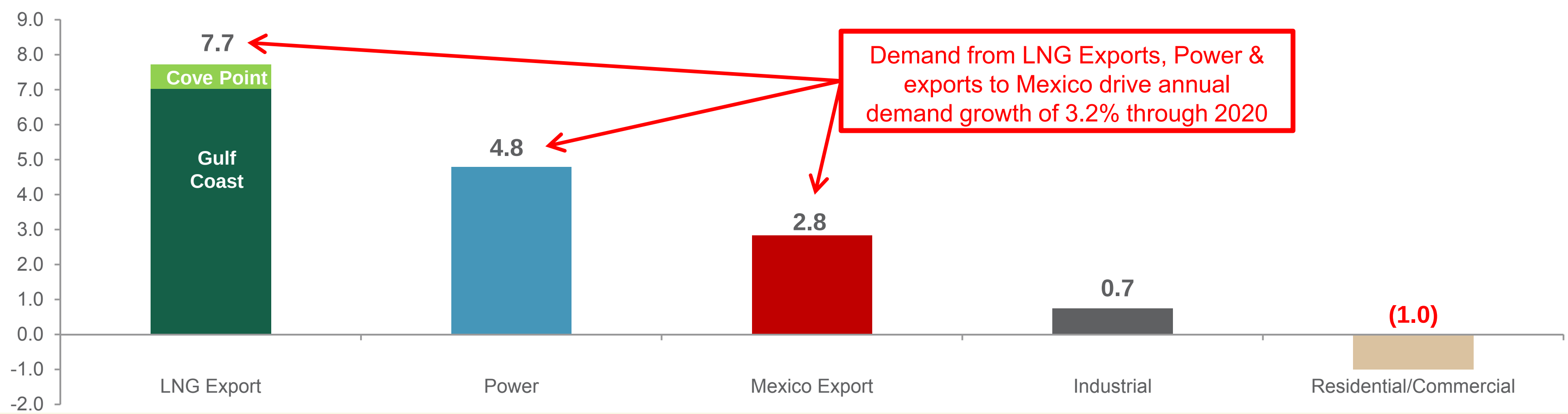
APPALACHIA WILL SUPPLY NATURAL GAS DEMAND GROWTH

- As LNG exports, Mexico exports and power generation drive demand, gas supply growth through 2020 is expected to be primarily driven by the Marcellus and Utica shales, given their low full cycle cost position and increasing takeaway capacity from the northeast
  – *Appalachia represents 90% of the forecasted 13.3 Bcf/d supply growth from 2015 to 2020*

US Gas Production Growth by Basin 2015-2020E (Bcf/d)

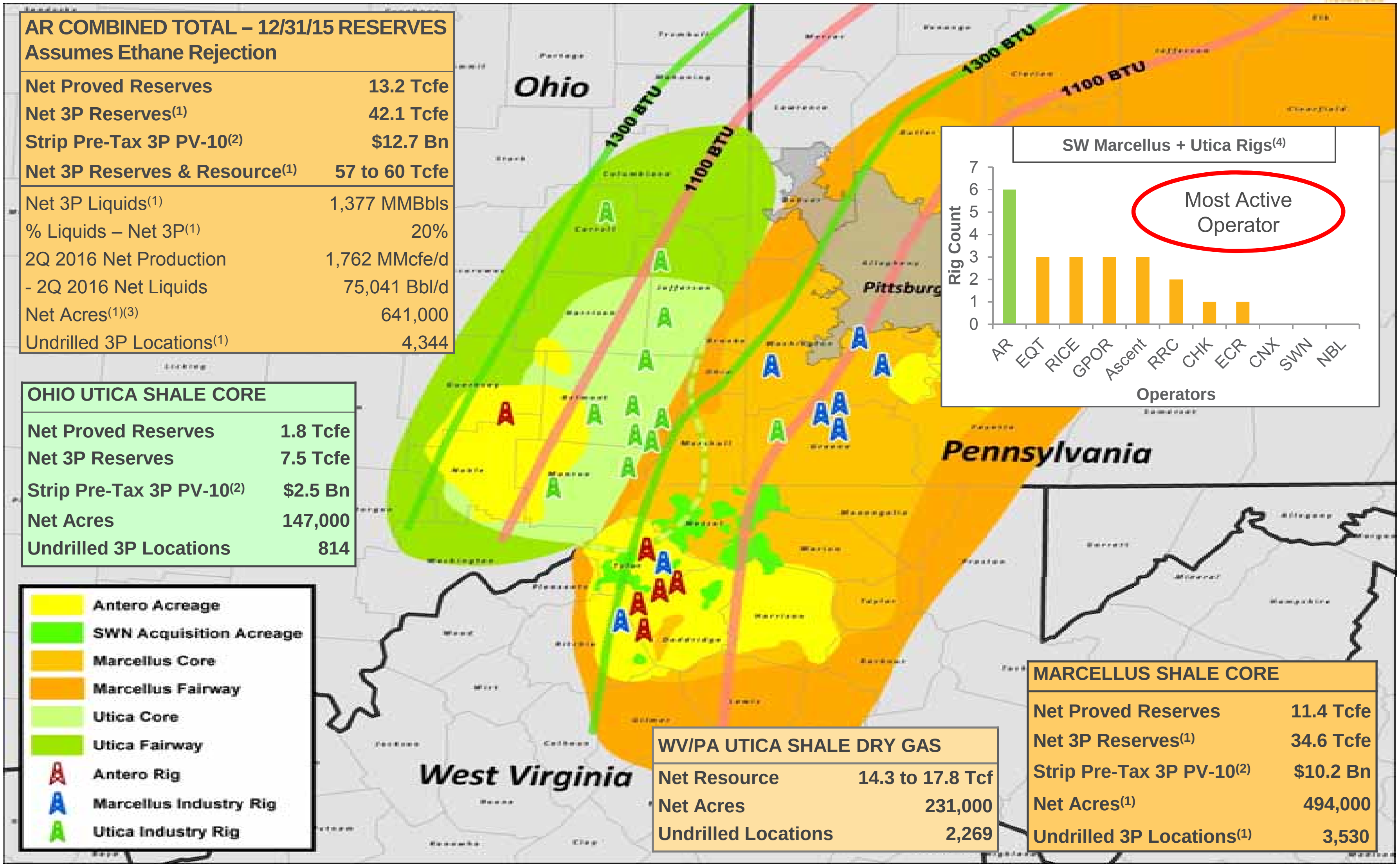


Total Incremental US Natural Gas Demand Growth of 13.3 Bcf/d Forecast for 2015-2020E



Source: Tudor, Pickering & Holt Research Note dated August 2016.

ANTERO WELL POSITIONED TO DRIVE SUPPLY GROWTH



AR COMBINED TOTAL – 12/31/15 RESERVES Assumes Ethane Rejection	
Net Proved Reserves	**13.2 Tcfe**
Net 3P Reserves[1]	**42.1 Tcfe**
Strip Pre-Tax 3P PV-10[2]	**$12.7 Bn**
Net 3P Reserves & Resource[1]	**57 to 60 Tcfe**
Net 3P Liquids[1]	1,377 MMBbls
% Liquids – Net 3P[1]	20%
2Q 2016 Net Production	1,762 MMcfe/d
- 2Q 2016 Net Liquids	75,041 Bbl/d
Net Acres[1][3]	641,000
Undrilled 3P Locations[1]	4,344

OHIO UTICA SHALE CORE	
Net Proved Reserves	1.8 Tcfe
Net 3P Reserves	7.5 Tcfe
Strip Pre-Tax 3P PV-10[2]	$2.5 Bn
Net Acres	147,000
Undrilled 3P Locations	814

WV/PA UTICA SHALE DRY GAS	
Net Resource	14.3 to 17.8 Tcf
Net Acres	231,000
Undrilled Locations	2,269

MARCELLUS SHALE CORE	
Net Proved Reserves	11.4 Tcfe
Net 3P Reserves[1]	34.6 Tcfe
Strip Pre-Tax 3P PV-10[2]	$10.2 Bn
Net Acres[1]	494,000
Undrilled 3P Locations[1]	3,530

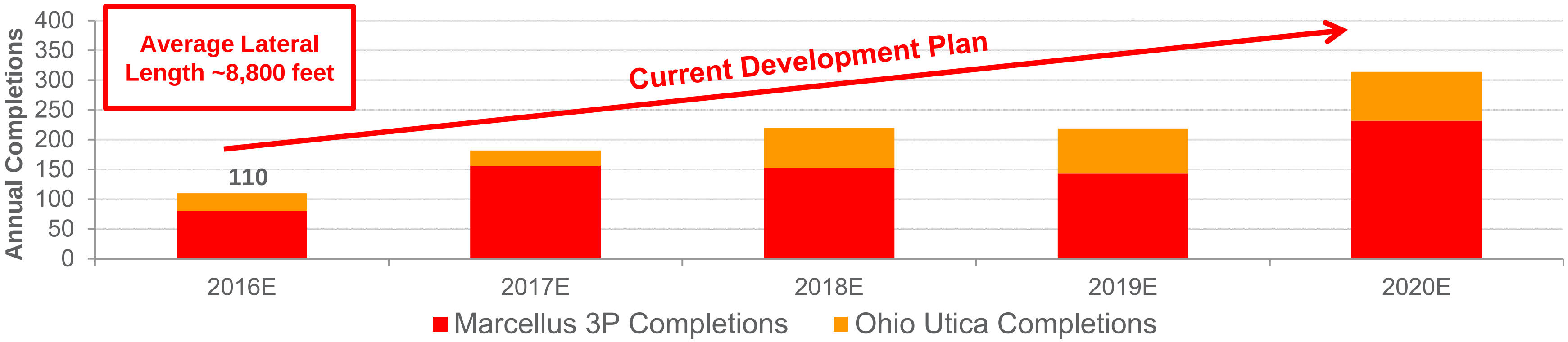
Note: 2015 SEC prices were $2.56/MMBtu for natural gas and $50.13/Bbl for oil on a weighted average Appalachian index basis.

1. *Pro forma for third-party pending acreage acquisition announced per press release dated 6/9/2016, updated for exercise of tag along right. 3P reserve additions are unaudited. 14 to 18 Tcf Utica dry resource in WV/PA.*
2. *3P reserve pre-tax PV-10 based on annual strip pricing for first 10-years and flat thereafter as of December 31, 2015. NGL pricing assumes 39%, 46% and 48% of WTI strip prices for 2016, 2017 and 2018 and thereafter, respectively. $1.5 billion 3P PV-10 unaudited estimate for pending acreage acquisition, using 12/31/2015 strip pricing and same year end 2015 assumptions. Strip pre-tax PV-10 is a non-GAAP financial measure. The standardized measure was $3.2 billion as of 12/31/2015.*
3. *Virtually all WV/PA Utica Shale net acres are included among the net acres of Marcellus Shale rights as they are stacked pay formations attributable to the same leasehold.*
4. *Antero and industry rig locations as of 7/22/2016, per RigData.*

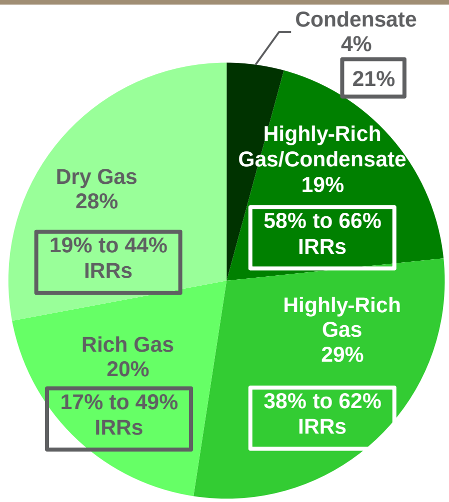
GROWTH ENGINE THROUGH 2020 AND BEYOND

Antero plans to develop over 1,000 horizontal locations in the Marcellus and Ohio Utica by the end of the decade while utilizing less than 25% of its current 3P drilling inventory

PLANNED ANTERO WELL COMPLETIONS BY YEAR



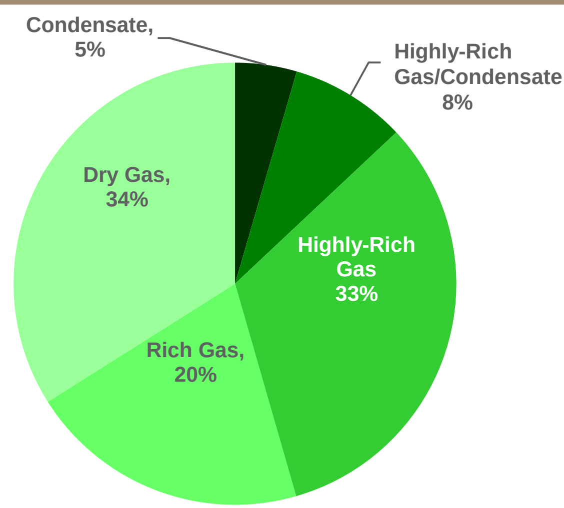
CURRENT UNDRILLED 3P LOCATIONS BY BTU REGIME [1]



4,344 Locations

Expect to place >1,000 Marcellus and Utica wells to sales by YE 2020

ESTIMATED YE 2020 UNDRILLED 3P LOCATIONS



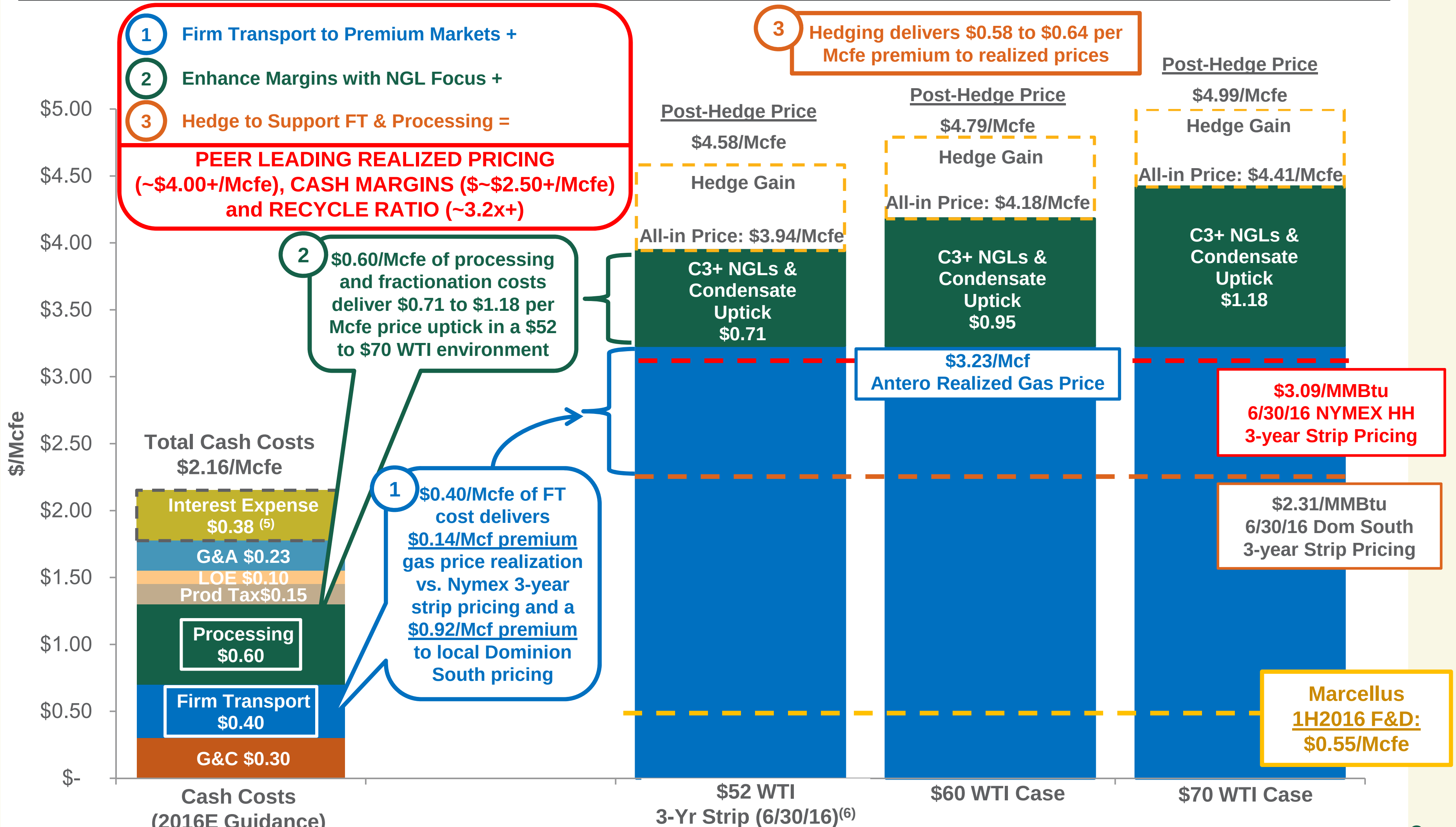
3,309 Locations YE 2020

1. *Marcellus and Utica 3P locations pro forma for pending acreage acquisition announced 6/9/2016. Excludes WV/PA Utica Dry locations.*

LEADING REALIZATIONS DELIVER…

- Antero's business strategy including firm transport to favorable markets, focus on liquids-rich drilling and hedging deliver market leading financial results

Unit Cash Cost vs. 3-Year Average Realized Pricing(1)(2)(3)(4)

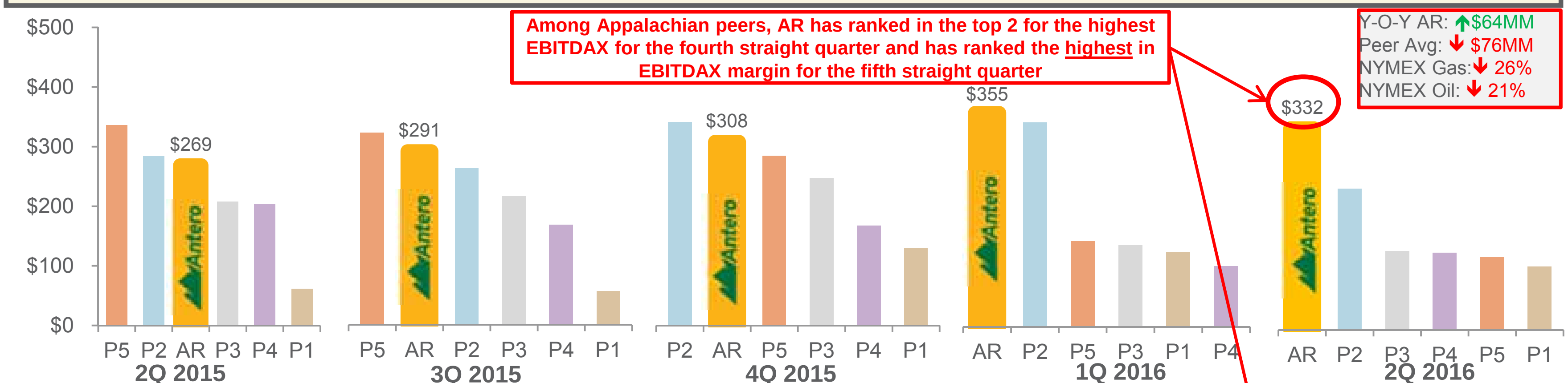


1. Excludes hedge gains and net marketing expense.
2. All three WTI sensitivity cases assume Henry Hub natural gas strip pricing through 2018, as of 6/30/16.
3. Assumes 2H2016-2018 weighted average C3+ NGL realization of 45% of WTI for each respective case.
4. Assumes 1250 BTU.
5. Based on 1H 2016 interest expense and actual production.
6. 6/30/2016 strip through 2018 equates to $52.35.

…HIGHEST EBITDAX & MARGINS AMONG PEERS

Antero has extended its lead among Appalachia Basin peers in both EBITDAX and EBITDAX margin

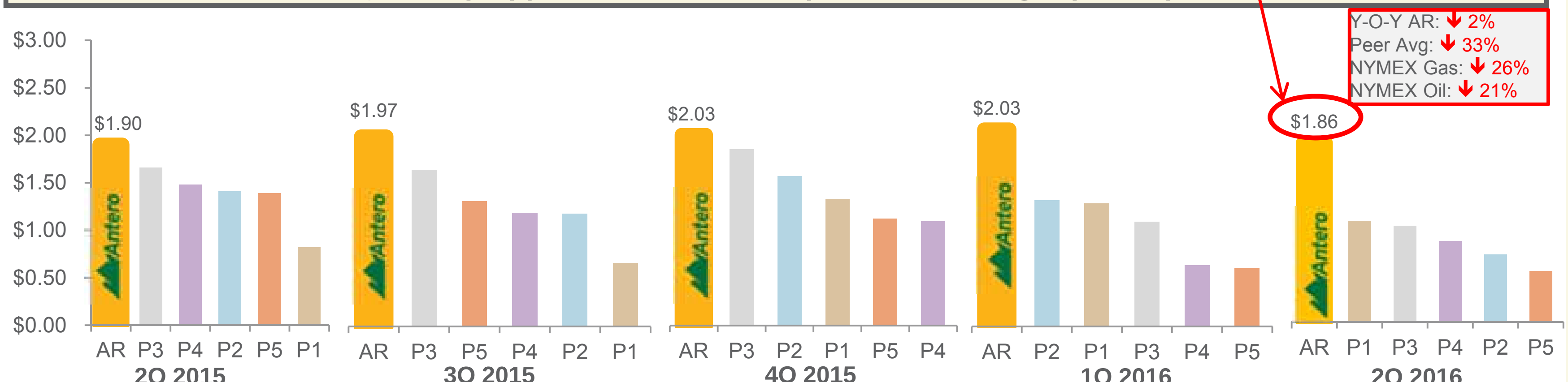
Quarterly Appalachian Peer Group EBITDAX ($MM)[1]



AR Peer Group Ranking – Improving Over Time

2Q 2015	3Q 2015	4Q 2015	1Q 2016	2Q 2016
#3	#2	#2	#1	#1

Quarterly Appalachian Peer Group EBITDAX Margin ($/Mcfe)[1]



AR Peer Group Ranking – Top Tier

2Q 2015	3Q 2015	4Q 2015	1Q 2016	2Q 2016
#1	#1	#1	#1	#1

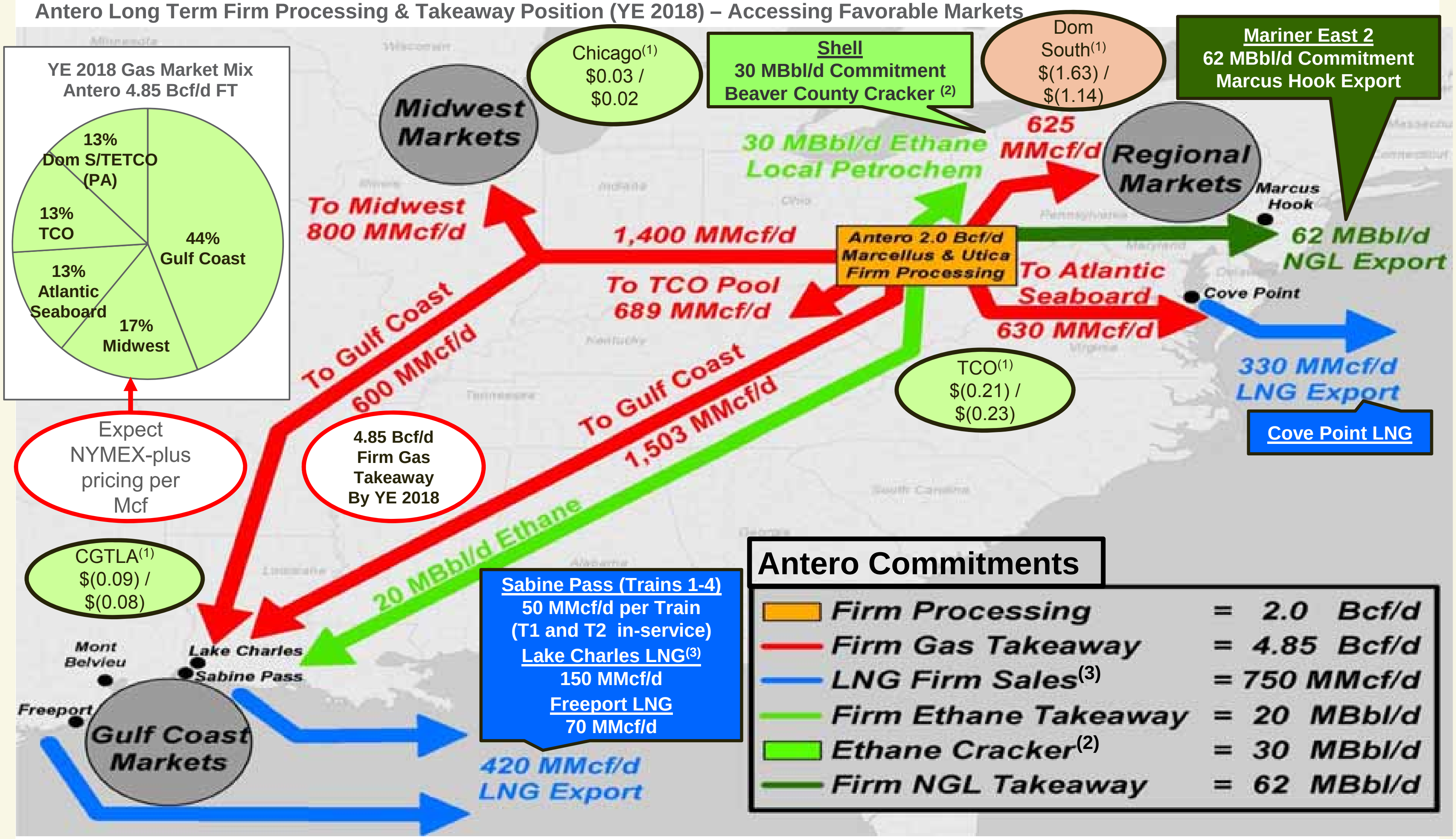
Note: AR and EQT EBITDAX margin excludes EBITDA from midstream MLP associated with noncontrolling interest. AR consolidated EBITDAX margin for 2Q 2016 was $2.07/Mcfe. CNX excludes EBITDAX contribution from coal operations.

1. Source: Public data from form 10-Qs and 10-Ks and Wall Street research. Peers include COG, CNX, EQT , RRC and SWN.

LARGEST FT PORTFOLIO IN APPALACHIA

- Antero's natural gas firm transportation (FT) portfolio builds to 4.85 Bcf/d by YE 2018 with 87% serving favorable markets, for an average demand fee of $0.46/MMBtu and positive weighted average basis differential to NYMEX after assumed Btu uplift for gas

Antero Long Term Firm Processing & Takeaway Position (YE 2018) – Accessing Favorable Markets



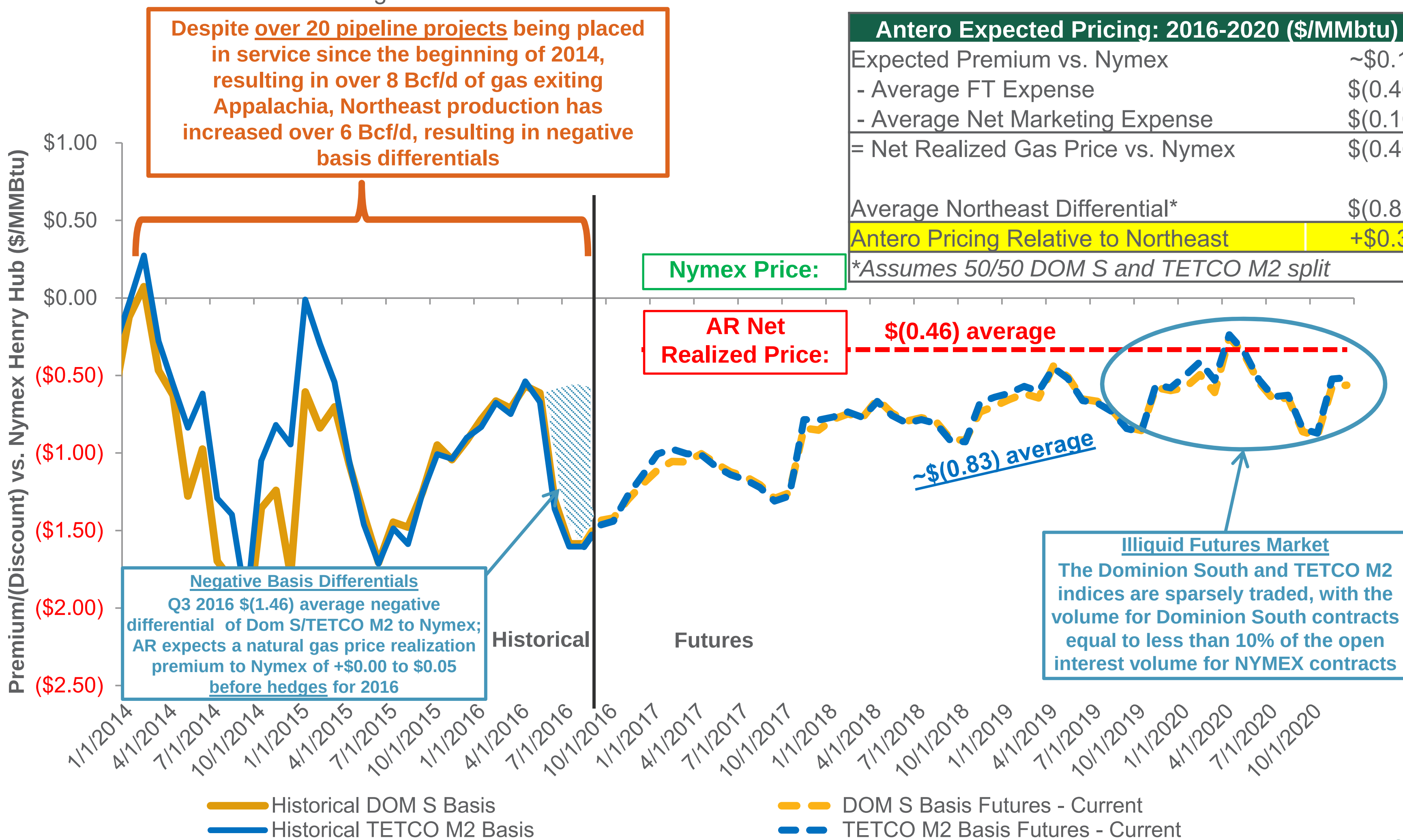
1. October 2016 and full year 2017 futures basis, respectively, provided by Intercontinental Exchange dated 8/31/2016. Favorable markets shaded in green.
2. Shell announced final investment decision (FID) on 6/7/2016.
3. Lake Charles LNG 150 MMcf/d commitment subject to Shell FID.

ANTERO FT ELIMINATES NORTHEAST BASIS RISK

Futures indicate an improvement in Northeast basis as new pipeline capacity is built, however, infrastructure expansions have historically been delayed and met by an increase in production, keeping Northeast basis wide

– Even with the tightening of local basis indicated in the futures market, Antero's expected netback after deducting FT costs through the end of the decade is over 20% higher than the local Dominion South and TETCO M2 indices

Antero Expected Pricing: 2016-2020 ($/MMbtu)	
Expected Premium vs. Nymex	~$0.10
- Average FT Expense	$(0.46)
- Average Net Marketing Expense	$(0.10)
= Net Realized Gas Price vs. Nymex	$(0.46)
Average Northeast Differential*	$(0.83)
Antero Pricing Relative to Northeast	+$0.37
*Assumes 50/50 DOM S and TETCO M2 split	



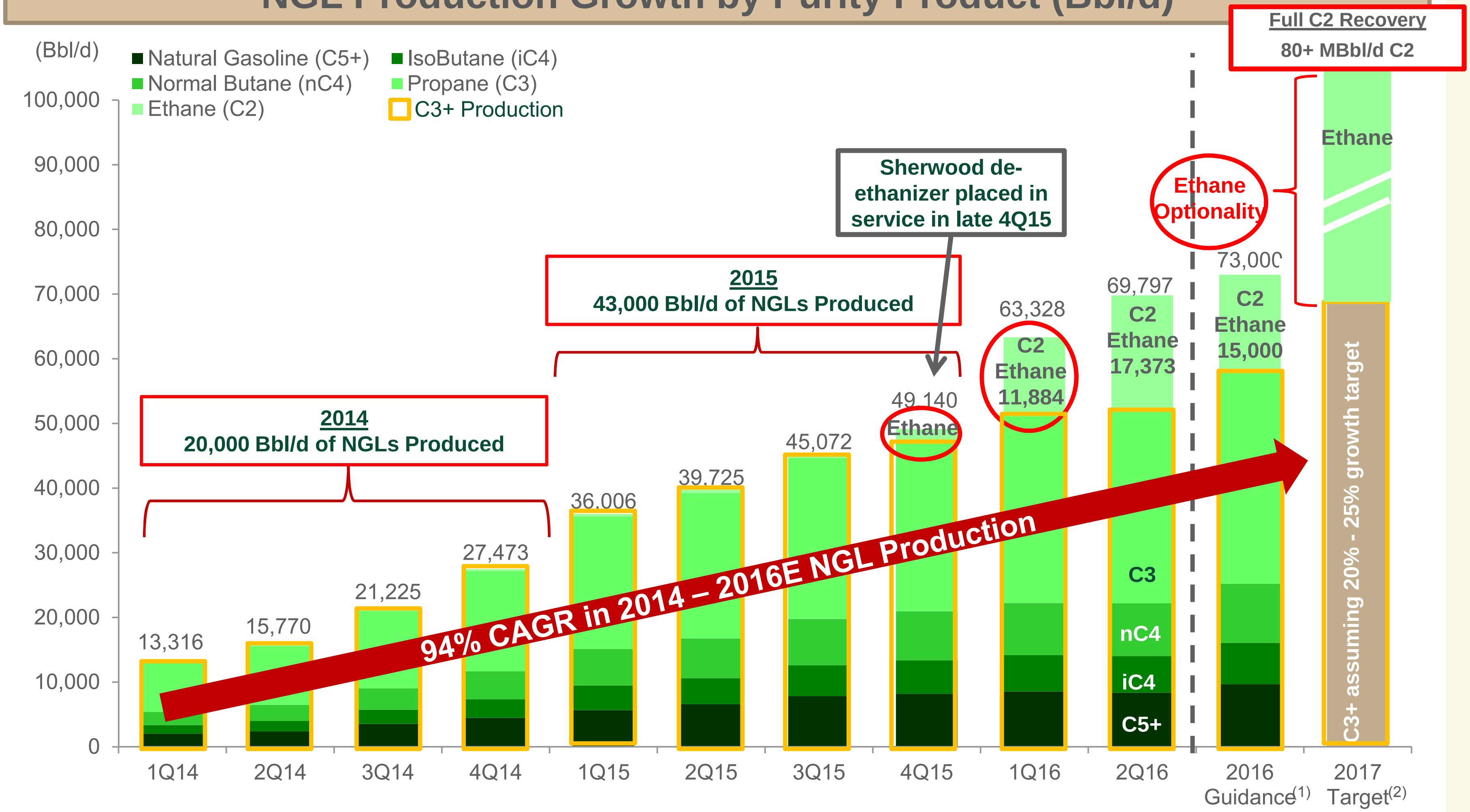
Source: Bloomberg and ICE futures as of 8/23/2016.

NGL GROWTH AND ETHANE OPTIONALITY

Antero continues to rapidly grow its liquids production, with 2015 year-over-year growth of 117% and 2016 NGL production growth guidance of 71%

- Developing significant ethane optionality with an estimated 85,000 Bbl/d of ethane in targeted production stream in 2017

NGL Production Growth by Purity Product (Bbl/d)

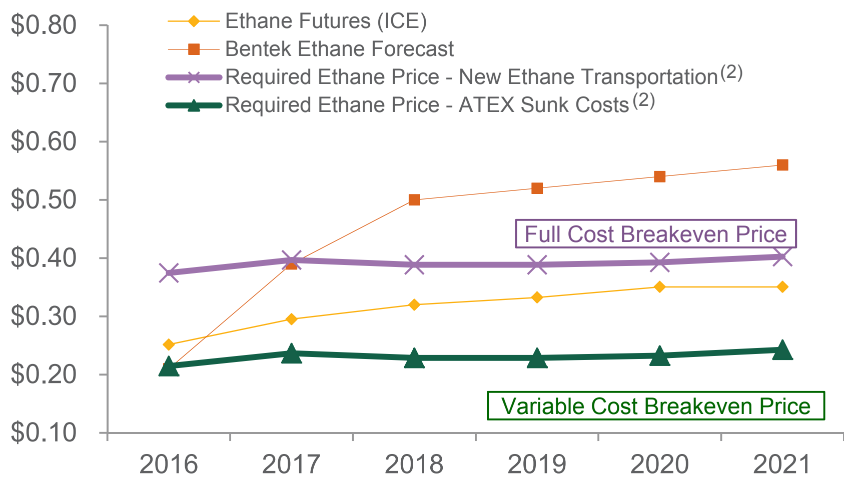


1. Assumes 10,000 Bbl/d of ethane and 52,500 Bbl/d of C3+, respectively, per guidance release on 4/27/2016. C3+ barrel composition based on 1Q16 actual barrel composition.
2. Assumes 20 – 25% year-over-year equivalent production growth in 2017. For illustrative purposes C3+ production growth assumed at same rate.

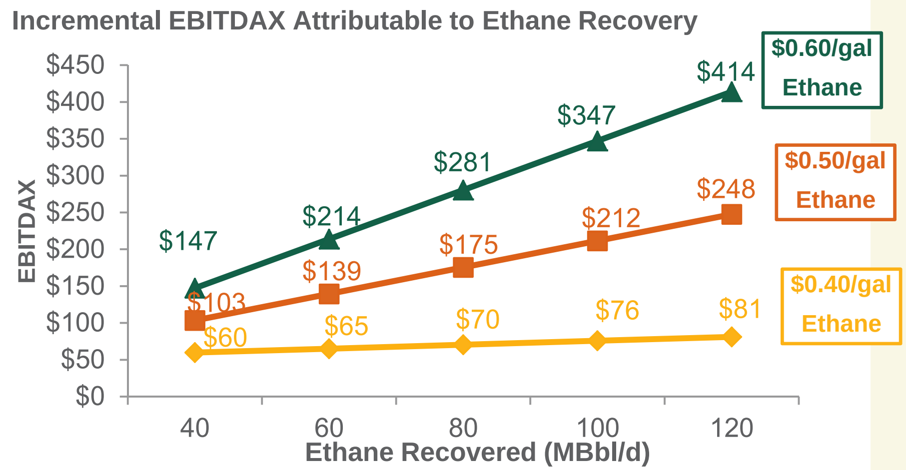
POSITIONED TO BENEFIT FROM C2 RECOVERY…

Antero has significant exposure to upside in ethane price (C2)

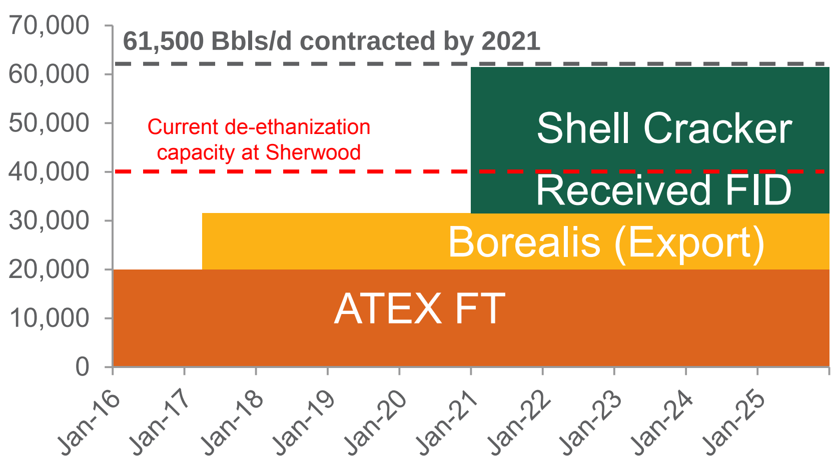
Ethane Prices ($/Gallon)[1]



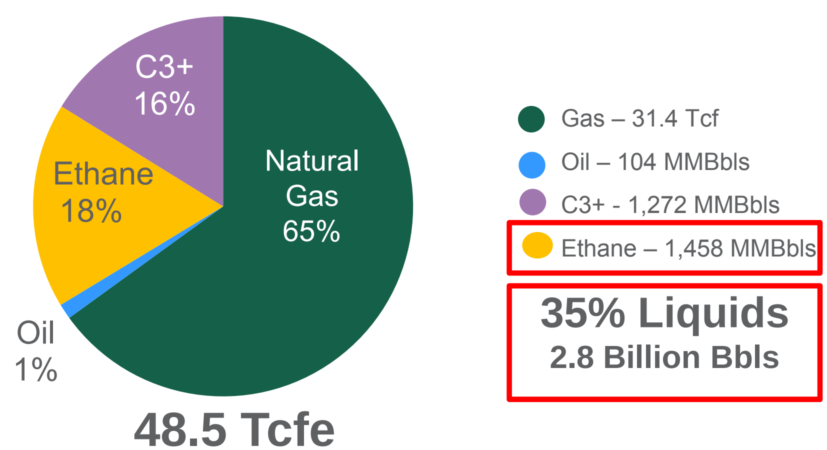
Ethane Upside Impact to AR[3]



Ethane Takeaway Capacity



Pro Forma 3P Reserves (Ethane Recovery)[4]



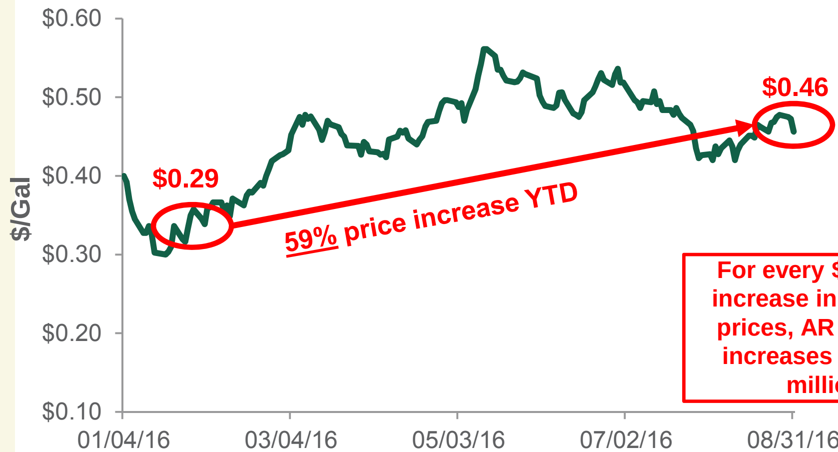
1. Ethane futures data from ICE as of 6/30/2016. Bentek forecast as of 4/26/2016.
2. Represents ethane price required to match TCO strip sales price on a realized basis. TCO strip as of 6/30/2016.
3. Represents incremental EBITDA associated with ethane recovery (vs. rejection) at prices ranging from $0.40 to $0.60 per gallon. Assumes (1) ATEX costs are sunk up to 20,000 Bbl/d, (2) $3.00 NYMEX natural gas prices and (3) Borealis firm sale at NYMEX plus pricing.
4. 12/31/2015 reserves assuming ethane recovery, pro forma for pending acreage acquisition.

…AND C3+ VOLUME GROWTH AND PRICE RECOVERY

Antero has 2.7 billion Bbls of net 3P NGL reserves

- **Mariner East 2 is expected to be in-service by mid-year 2017 which should significantly reduce Antero's differential to MB pricing**

Propane Pricing Improvement (1)



For every $0.10/gal increase in propane prices, AR revenue increases by ~$45 million

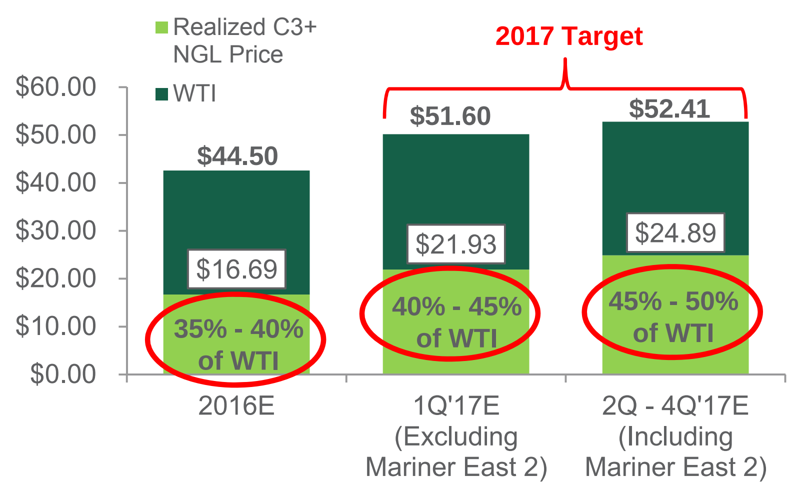
Propane Upside Impact to AR

	Mont Belvieu Pricing	Production (MBbl/d)	Propane Revenue @ MB ($MM) (2)
Q2 2016 Annualized	$0.49	30	$227

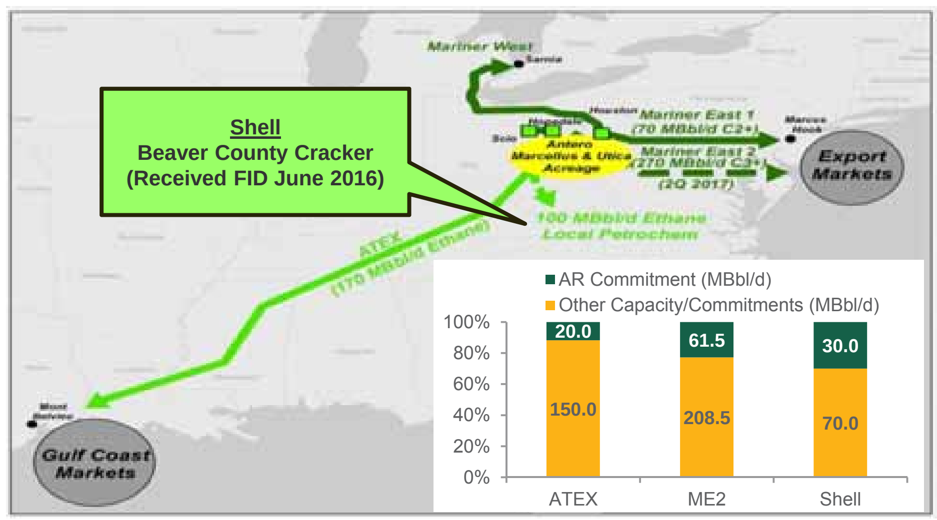
Annual Propane Revenue Sensitivity ($MM)

MB Pricing	Propane Production (MBbl/d)				
	30	35	40	45	50
$0.85	$394	$456	$521	$586	$652
$0.75	$348	$402	$460	$517	$575
$0.65	$301	$349	$399	$448	$498
$0.55	$255	$295	$337	$379	$422
$0.45	$209	$241	$276	$310	$345

2016 and 2017 NGL C3+ Guidance / Target (3)



NGL Takeaway

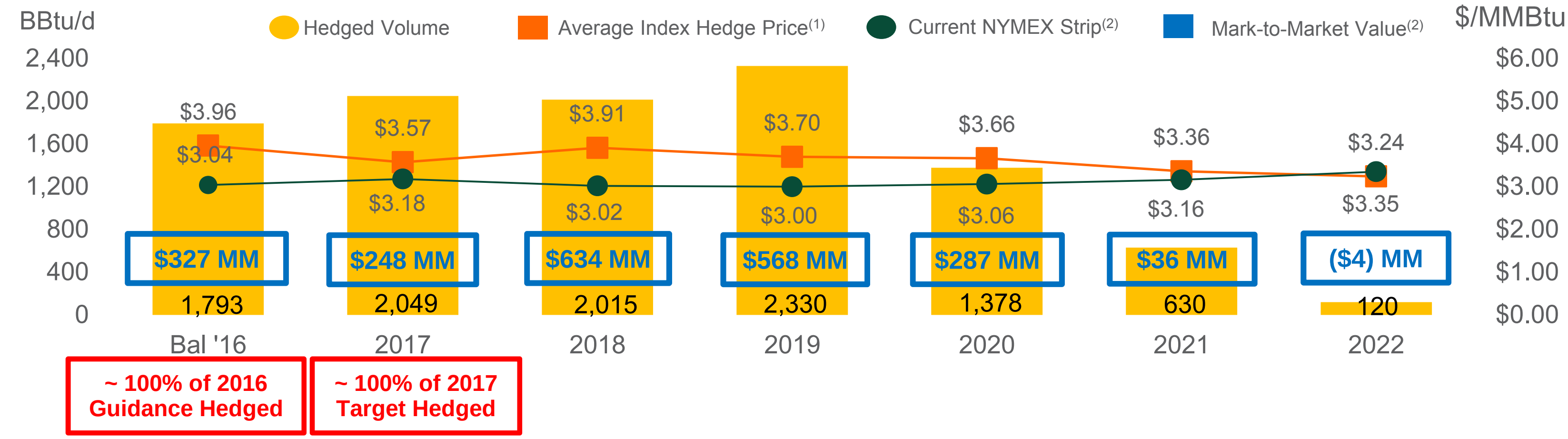


1. Based on Mont Belvieu (MB) pricing as of 8/31/2016.
2. Before Northeast differentials.
3. Based on strip pricing as of 6/30/2016 and associated NGL differentials to Mont Belvieu.

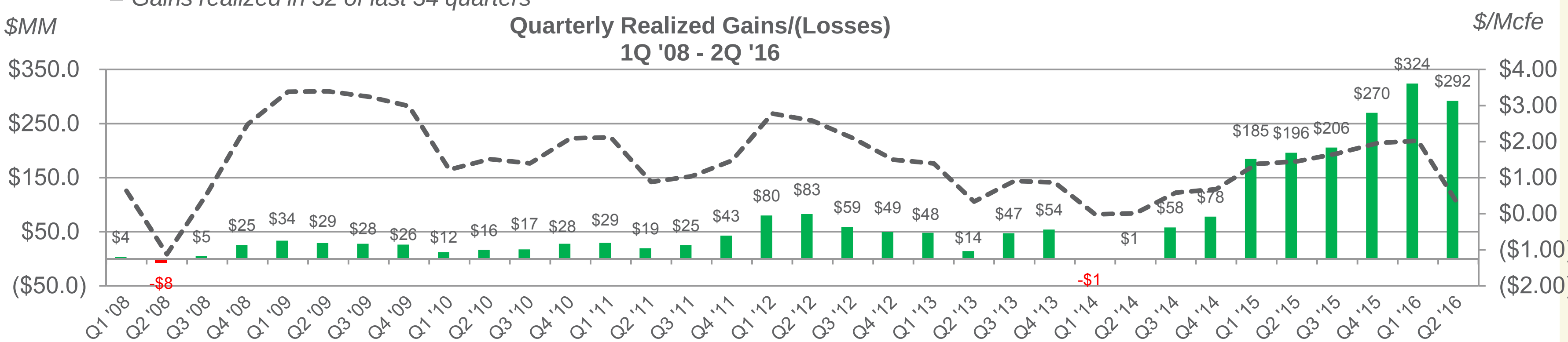
HEDGING INTEGRAL TO ANTERO BUSINESS MODEL

- ~$2.1 billion mark-to-market unrealized gain based on 6/30/2016 prices
- 3.4 Tcfe hedged from July 1, 2016 through year-end 2022 at $3.71 per MMBtu

COMMODITY HEDGE POSITION



- Hedging is a key component of Antero's business model due to the large, repeatable drilling inventory and infrastructure commitments needed to optimize pricing
- Antero has realized $2.4 billion of gains on commodity hedges since 2008
  - *Gains realized in 32 of last 34 quarters*

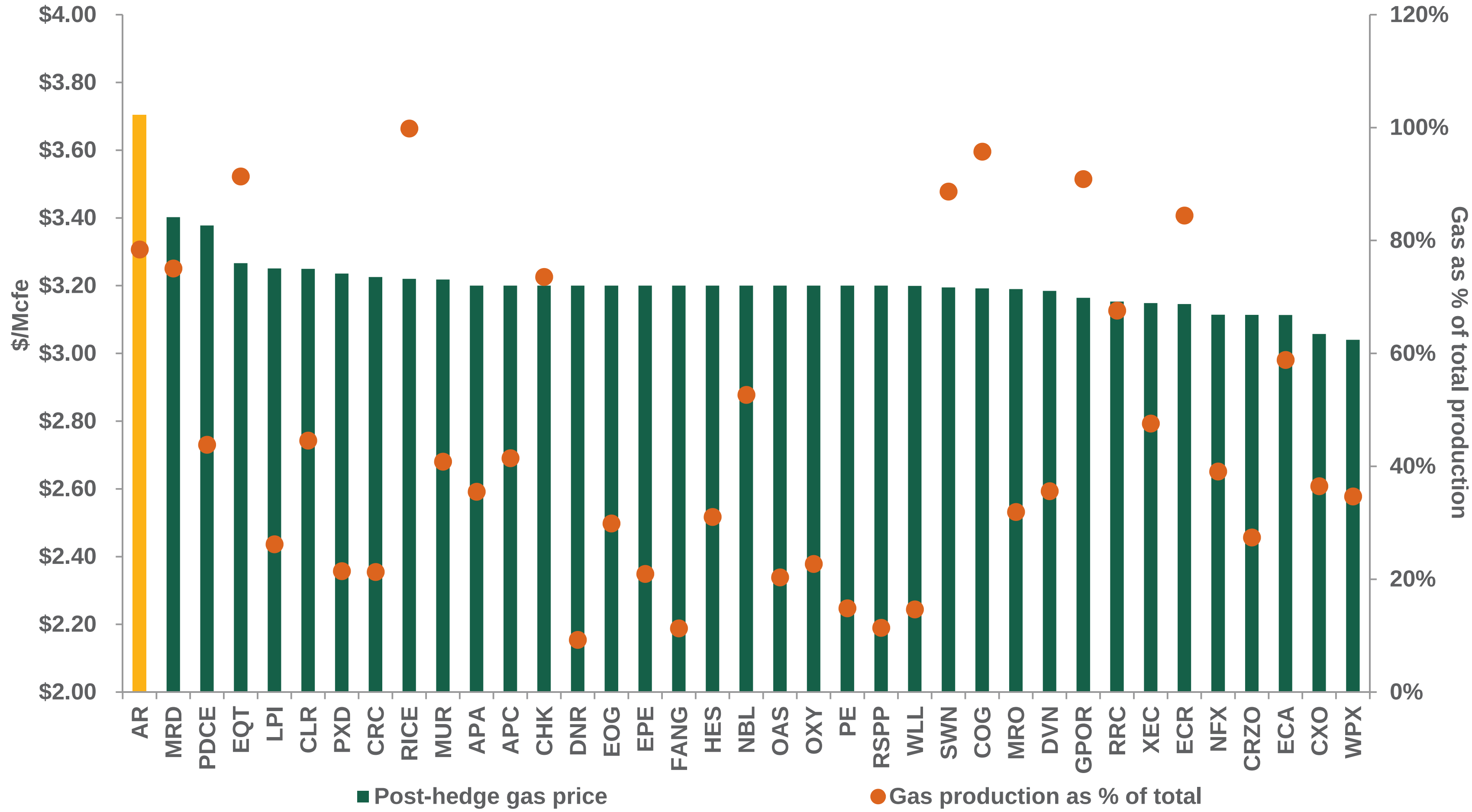


1. *Weighted average index price based on volumes hedged assuming 6:1 gas to liquids ratio; excludes impact of TCO basis hedges. 30,000 Bbl/d of propane hedged in 2016, 31,500 Bbl/d hedged in 2017 and 2,000 Bbl/d hedged in 2018.*
2. *As of 6/30/2016.*

BEST NATURAL GAS HEDGE POSITION FOR 2017

AR is 94% hedged through 2018 at $3.81/MMBtu, a $0.78 premium to the current strip

Effective post-hedge Henry Hub gas price using 2017 Henry Hub of $3.20/MMBtu



Source: Goldman Sachs August 25, 2016 Research note.

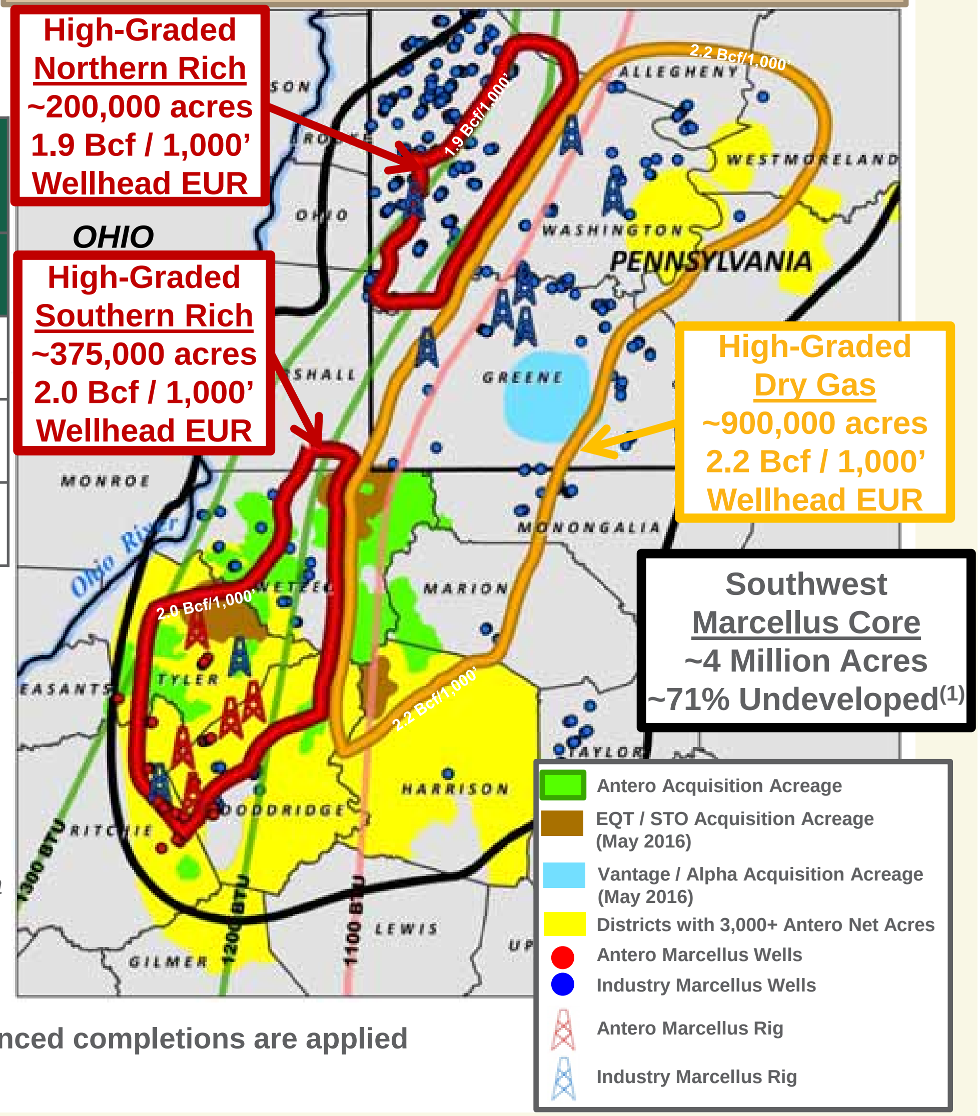
LEADERSHIP IN MARCELLUS HIGH-GRADED CORE

- **Antero's internal reserve engineers have analyzed over 3,000 wells in southwest Marcellus, which led to the high-graded core outlines to the right**
- **Average wellhead recovery including condensate but before processing is as follows:**

High-Graded Core Areas:	Most Active Operators	% Undeveloped[1]	Advanced Completions (>1,300 lbs/ft)		All Completions	
			EUR / 1,000'	Wells	EUR / 1,000'	Wells
Northern Rich Gas	RRC, CNX, NBL	58%	1.9	234	1.8	355
Southern Rich Gas	AR, EQT, SWN	73%	2.0	174	1.8	400
Dry Gas	EQT, CVX, RRC, CNX	75%	2.2	273	2.0	516

- **Best Rock – Washington and Greene Counties, PA and Wetzel, Tyler and Doddridge Counties, WV all have significant areas that average 1.9 to 2.2 Bcf/1,000' of recoveries at the wellhead using advanced completions (>1,300 lbs per foot and 33 Bbls of water per foot)**
- **Pro forma for the pending transaction, Antero controls approximately 237,000 undeveloped gross acres in the High-Graded areas**
  - *Controls 53% of the undeveloped Southern Rich Gas area and 13% of the undeveloped Dry Gas area*
  - *1,600 undeveloped high-graded core locations with 8,700' average lateral length*
- **Potential for high-graded core outlines to expand as advanced completions are applied more broadly across the Marcellus core**

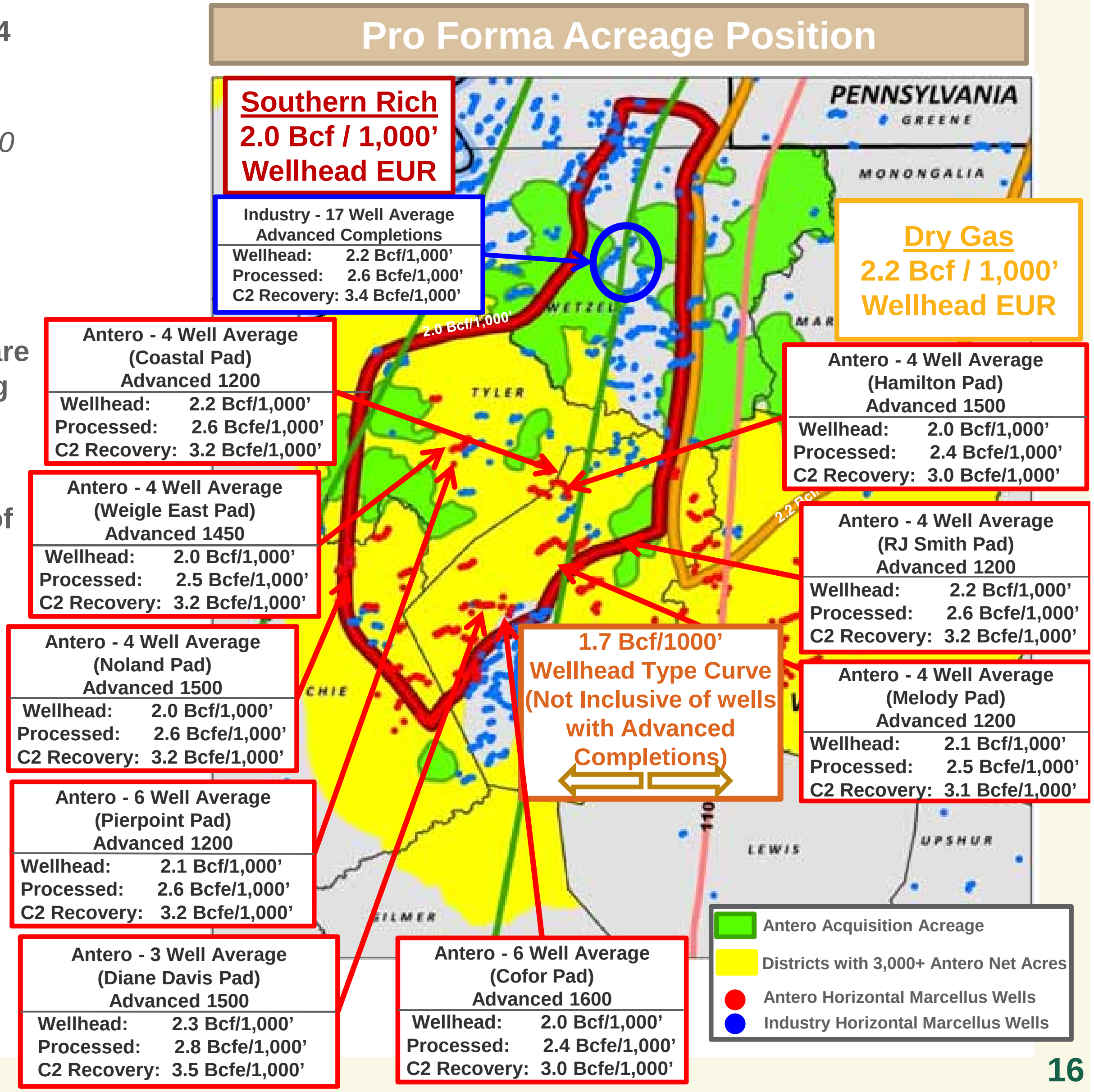
Southwest Marcellus High-Graded Core



1) % undeveloped calculation considers urban areas as "developed".

EXCELLENT WELL RESULTS IN HIGH-GRADED CORE

- Antero and industry have completed 174 wells with advanced completions in the High-Graded Southern Rich Core
  - *Antero wellhead EURs range from 2.0 to 2.3 Bcf/1,000' on adjacent map*
  - *Antero processed EURs with ethane recovery range from 3.0 to 3.5 Bcfe/1,000'*
- Wellhead EURs in Southern Rich Core are significantly higher than Antero booking type curve of 1.7 Bcf/1,000'
- Antero advanced completions have utilized 1,300 to 1,500 pounds per foot of proppant
  - *Recent pilots are utilizing 1,750 to 2,000 pounds per foot of proppant with results to come*

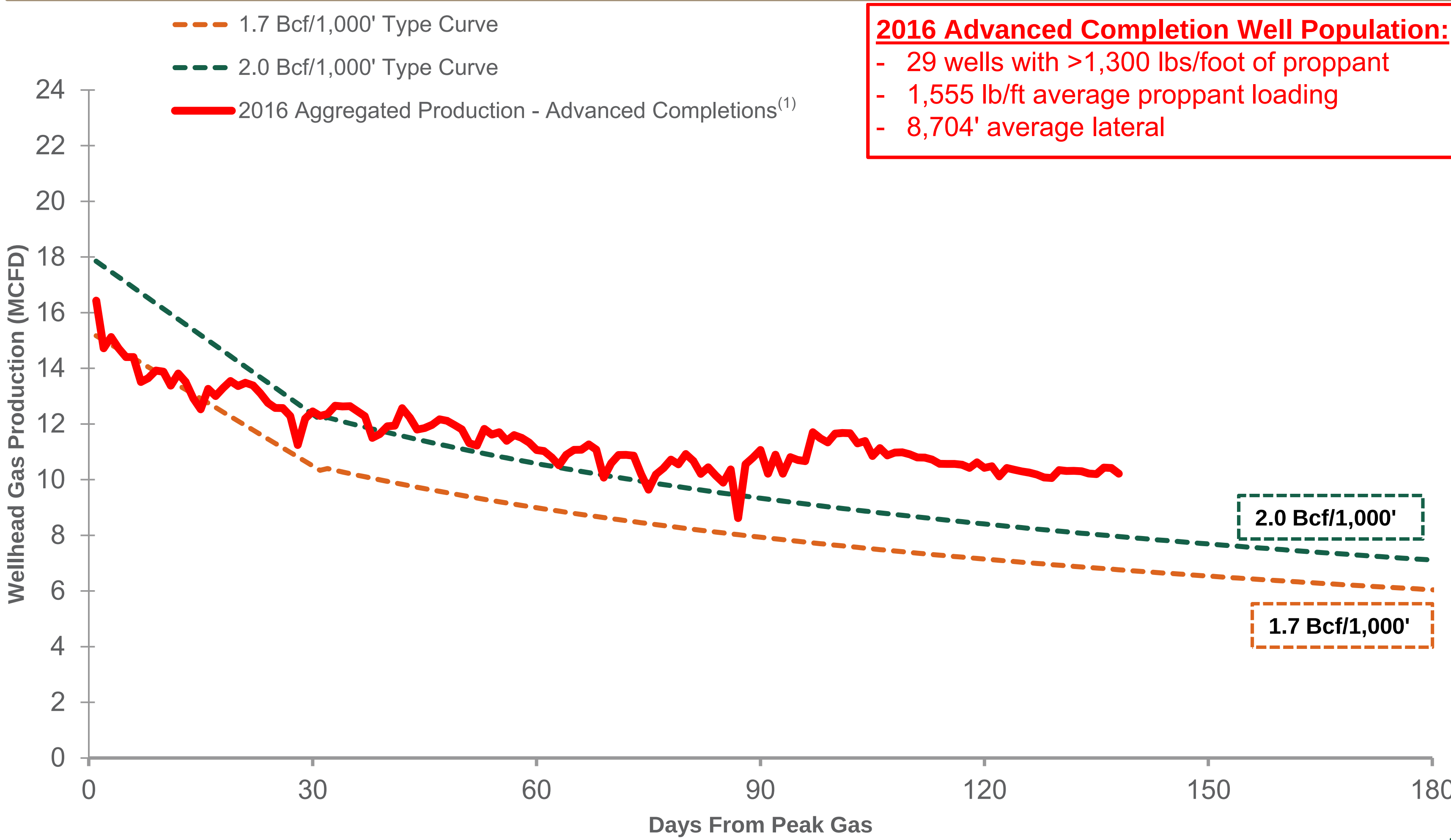


1. Includes projects currently under construction.

ADVANCED COMPLETIONS DRIVING HIGHER EURs

The initial performance of the 29 wells completed in 2016 using greater than 1,300 lb/ft has exceeded both our 1.7 Bcf/1,000' booking type curve and 2.0 Bcf/1,000' target through 140 days

2016 Marcellus Wells with Proppant Loading >1,300 pounds per foot(1)



2016 Advanced Completion Well Population:

- 29 wells with >1,300 lbs/foot of proppant
- 1,555 lb/ft average proppant loading
- 8,704' average lateral

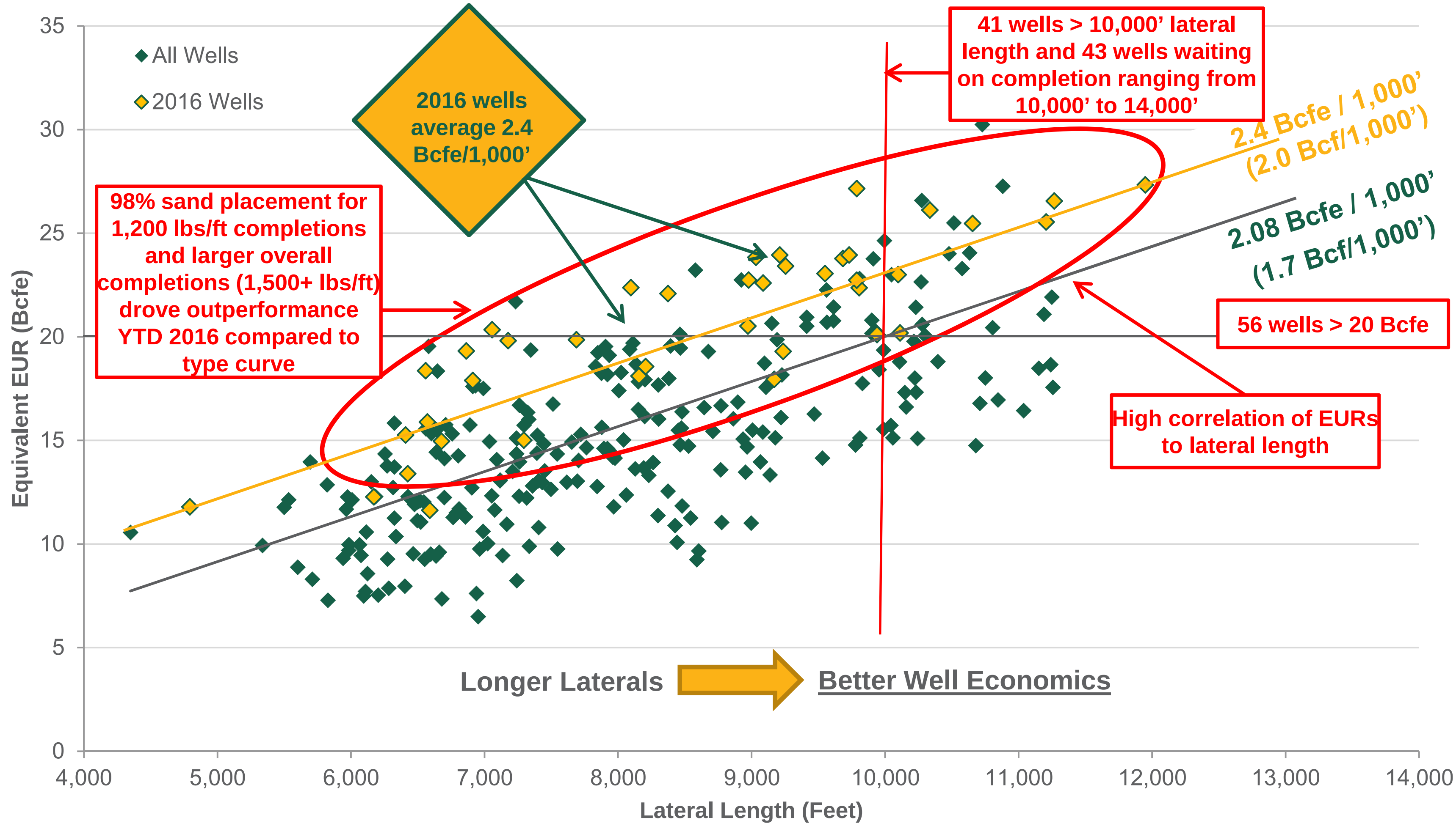
1. *All 29 Antero Marcellus wells with completions of >1,300 lb/ft of proppant normalized to time zero, production for each well normalized to 9,000' lateral length.*

LONGER LATERALS DRIVING VALUE CREATION

High correlation of EURs to lateral length – no degradation in results out to 12,000' laterals

- Antero has led the way with long lateral drilling programs – 2Q 2016 completions had average F&D cost of $0.46 per Mcfe

Antero Marcellus EUR vs. Lateral Length(1)(2)



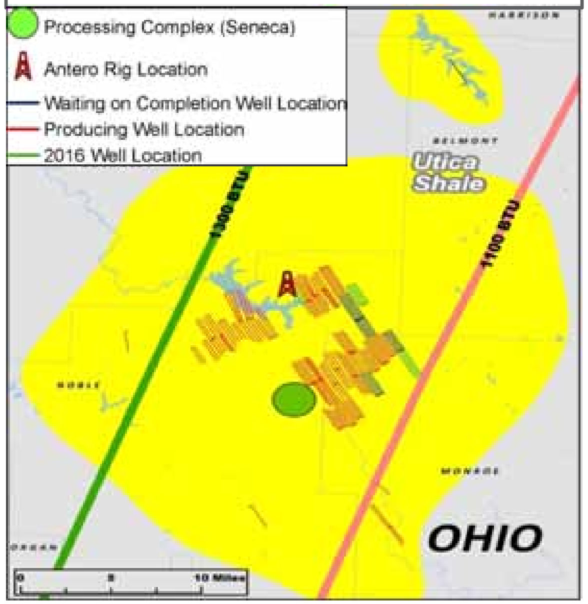
1. *All 280 wells completed since 2014 when Antero transitioned to shorter stage length completions (SSL).*
2. *EUR's include condensate and NGL processing (C3+) but assume ethane rejection.*

CONTINUOUS OPERATING IMPROVEMENT

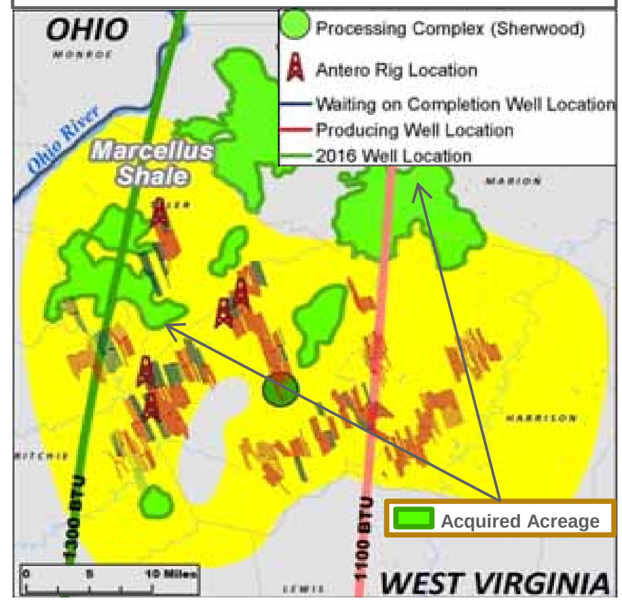
Operating Highlights

- Top 20 best drilling footage days in Marcellus since 2009 have all occurred in 2016, including 7,274' drilled in 24 hours in West Virginia on the Hunter 1H
- Recently drilled and cased longest lateral in company history at 14,024 feet
- Stayed within targeted zone for 95% of lateral length of all wells drilled in Q2 2016
- Increased sand placement during completions to 99% in Q2 2016
- Utilizing new floating casing procedure, reducing casing run time by over 12 hours
- Increased proppant and water loading by 25% in 2016 with encouraging results to date

Utica Shale Ohio



Marcellus Shale



	Utica 2014	Utica 2015	Utica Q2 2016	Utica Q2 2016 vs. 2014	Marcellus 2014	Marcellus 2015	Marcellus Q2 2016	Marcellus Q2 2016 vs. 2014
Activity Levels								
Average Rigs Running	4	5	1	(75%)	14	9	6	(57%)
Average Completion Crews	2.0	3.0	1.0	(50%)	5.5	2.0	3.5	(36%)
Operational Improvements								
Drilling Days	29	31	16	(45%)	29	24	15	(48%)
Average Lateral Length (Ft)	8,543	8,575	9,000	5%	8,052	8,910	9,000	12%
Stages per Well	47	49	51	9%	40	45	45	12%
Stage Length	183	175	175	4%	200	200	200	0%
Stages per Day	3.2	3.7	4.4	38%	3.2	3.5	3.9	22%
Well Cost & Performance Improvements								
D&C per 1,000' of lateral ($MMs)	$1.55	$1.36	$1.04	(33%)	$1.34	$1.18	$0.90	(33%)
Wellhead EUR per 1,000' of lateral (Bcf) [1]	1.4	1.6	1.6	14%	1.5	1.7	2.0	33%
Processed EUR per 1,000' of lateral (Bcfe) [1][2]	1.5	1.8	1.8	20%	1.8	1.9	2.3	28%
Net development cost (F&D) per Mcfe [2][3]	$1.28	$0.94	$0.72	(44%)	$0.88	$0.73	$0.46	(47%)

1. *Based on statistics for wells completed within each respective period.*
2. *Ethane rejection assumed.*
3. *Current D&C cost per 1,000' lateral divided by net EUR per 1,000' lateral assuming 81% NRI in Utica and 85% NRI in Marcellus.*

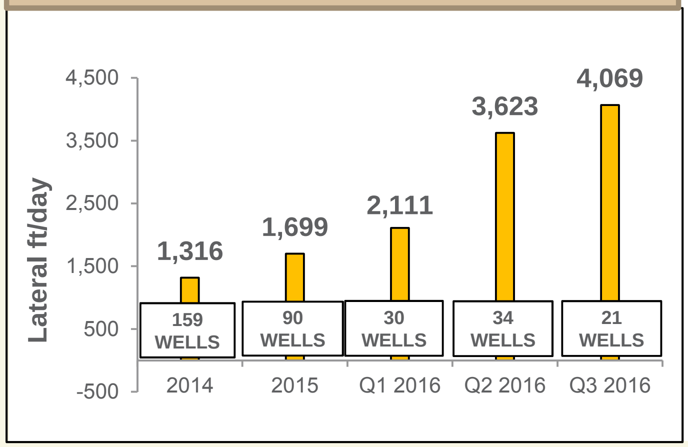
STEP CHANGE IN MARCELLUS DRILLING FOOTAGE

New drilling techniques and technologies are shaving 10 days off lateral drilling times and up to 25% off drilling AFEs

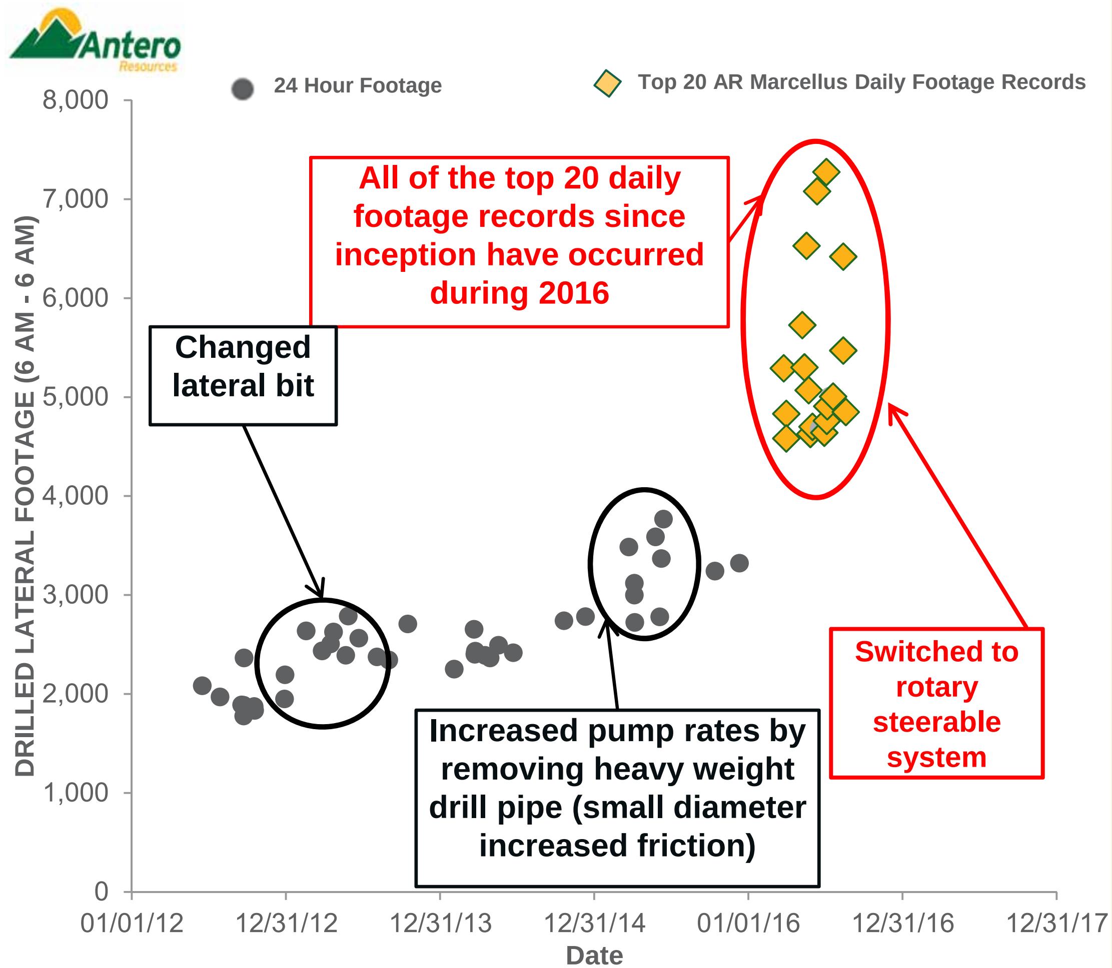
Key Drilling Highlights:

- Driven by technology and process advancements, **all of the top 20 Antero daily footage records have been achieved in 2016**, quickly establishing a new benchmark in Marcellus drilling performance
- Drilled **7,274' feet in a lateral in 24 hours**, exceeding previous record by over 1,000 feet
- Lateral **feet drilled per day has increased 3x** since 2014 to 4,069' in 3Q 2016

Marcellus Average Lateral Ft/Day

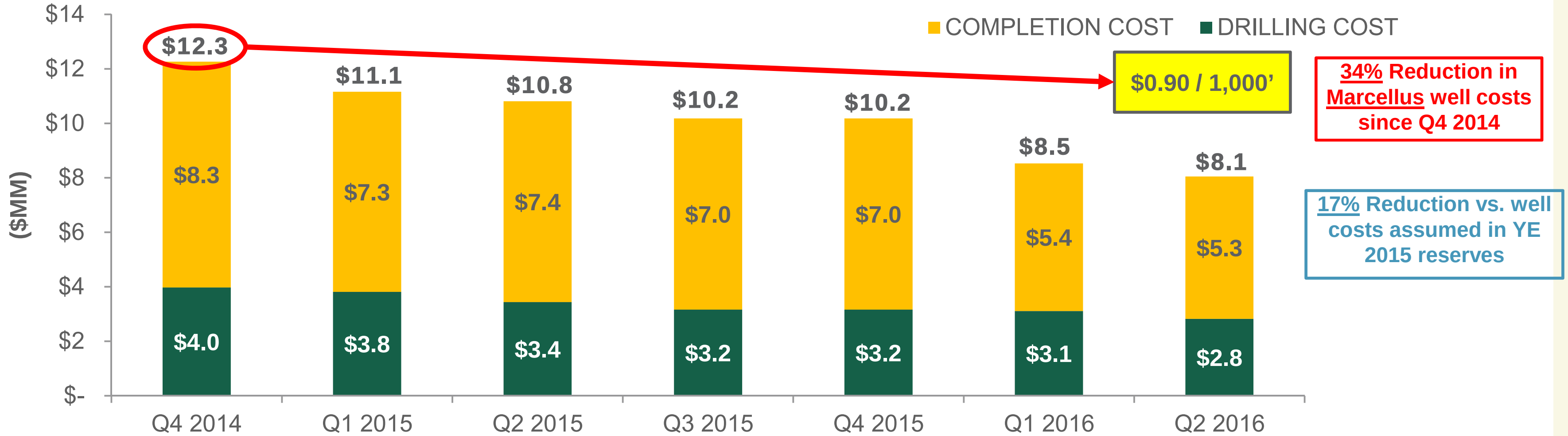


Top 50 AR Marcellus Daily Footage Records

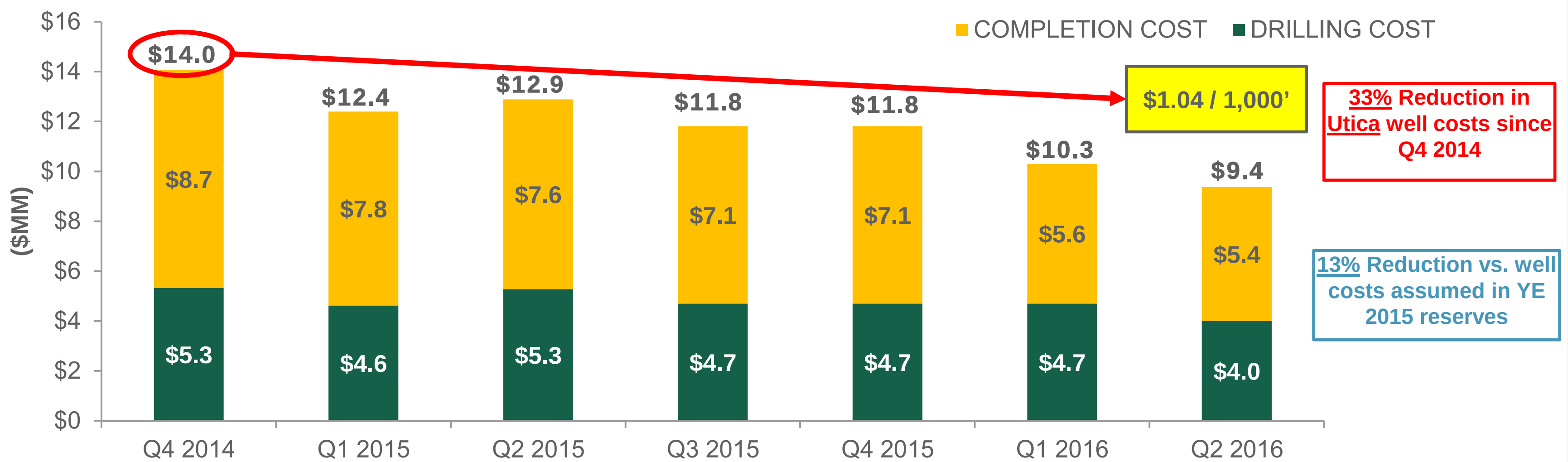


PROVEN TRACK RECORD OF WELL COST REDUCTIONS

Marcellus Well Cost Reductions for a 9,000' Lateral ($MM)[1]



Utica Well Cost Reductions for a 9,000' Lateral ($MM)[2]



NOTE: Based on statistics for drilled wells within each respective period.

1. *Based on 200 ft. stage spacing.*
2. *Based on 175 ft. stage spacing.*

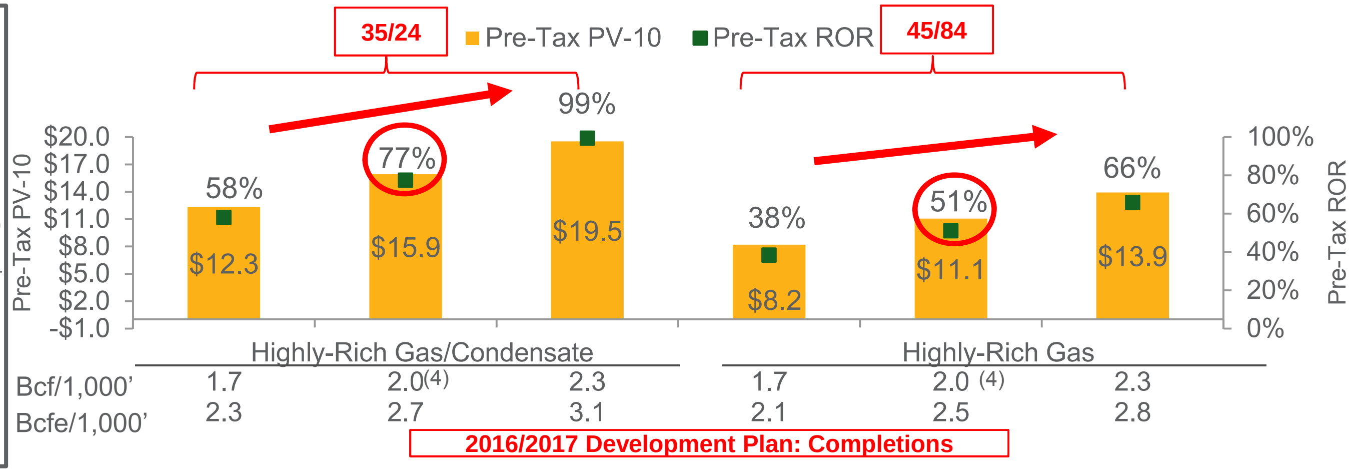
MARCELLUS UPSIDE POTENTIAL

- 33% lower well cost per 1,000' lateral and 33% higher EUR per 1,000' since 2014 are driving rates of return significantly higher despite lower strip pricing

Assumptions

- Natural Gas – 6/30/2016 strip
- Oil – 6/30/2016 strip
- NGLs – 37.5% of Oil Price 2016; ~50% of Oil Price 2017+

	NYMEX ($/MMBtu)	WTI ($/Bbl)	C3+ NGL[2] ($/Bbl)
2016	$3.04	$50	$22
2017	$3.18	$52	$26
2018	$3.02	$54	$27
2019	$3.00	$55	$28
2020	$3.06	$55	$28
2021-25	$3.53	$58	$30



Classification[1]		**Highly-Rich Gas/Condensate**			**Highly-Rich Gas**	
BTU Regime	**1275-1350**	**1275-1350**	**1275-1350**	**1200-1275**	**1200-1275**	**1200-1275**
EUR (Bcfe):	20.8	24.4	27.9	18.8	22.1	25.2
EUR (MMBoe):	3.5	4.1	4.7	3.1	3.7	4.2
% Liquids:	33%	33%	33%	24%	24%	24%
Well Cost ($MM):	$8.1	$8.1	$8.1	$8.1	$8.1	$8.1
Bcf/1,000'	1.7	2.0	2.3	1.7	2.0	2.3
Bcfe/1,000':	2.3	2.7	3.1	2.1	2.5	2.8
Net F&D ($/Mcfe):	$0.46	$0.39	$0.34	$0.51	$0.43	$0.38
Pre-Tax NPV10 ($MM):	$12.3	$15.9	$19.5	$8.2	$11.1	$13.9
Pre-Tax ROR:	58%	77%	99%	38%	51%	66%
Payout (Years):	1.5	1.1	0.9	2.1	1.6	1.3
Breakeven NYMEX Gas Price ($/MMBtu)[5]	$1.22	$0.95	$0.76	$2.02	$1.77	$1.57

	Highly-Rich Gas/Condensate	Highly-Rich Gas
Gross 3P Locations[3]:	557	1,052
Pro Forma Gross 3P Locations[3]:	664 (19% Increase)	1,235 (17% Increase)

1. 6/30/2016 pre-tax well economics based on a 9,000' lateral, 6/30/2016 natural gas and WTI strip pricing for 2016-2025, flat thereafter, NGLs at 37.5% of WTI for 2016 and ~50% of WTI thereafter, and applicable firm transportation and operating costs including 50% of Antero Midstream fees. Well cost estimates include $1.2 million for road, pad and production facilities. Assumes ethane rejection.
2. Pricing for a 1225 BTU y-grade ethane rejection barrel. NGLs at 37.5% of WTI for 2016 and ~50% of WTI for 2017 and thereafter. NGL prices are forecast to increase in 2017 relative to WTI due to projected in-service date of Mariner East 2 project allowing for a significant increase in AR NGL exports via ship.
3. Undeveloped Marcellus well locations as of 12/31/2015 adjusted for 6/30/2016 net acreage and pending acreage acquisition.
4. Represents actual results for 1Q 2016.
5. Breakeven price for 15% pre-tax rate of return.

STRONG BALANCE SHEET AND FLEXIBILITY

Antero Resources (NYSE:AR)

Pro Forma 6/30/2016 Debt

Debt Type	$MM
Credit facility	$556
6.00% senior notes due 2020	525
5.375% senior notes due 2021	1,000
5.125% senior notes due 2022	1,100
5.625% senior notes due 2023	750
Total	**$3,931**

Liquid Non-E&P Assets

Asset Type	$MM
Commodity derivatives[1]	$2,096
AM equity ownership[2]	3,018
Cash	19
Total	**$5,133**

Liquid "non-E&P assets" of $5.1 Bn significantly exceeds total debt of $3.9 Bn pro forma for equity offering shoe exercise

Pro Forma Liquidity

Asset Type	$MM
Cash	$19
Credit facility – commitments[3]	4,000
Credit facility – drawn	(556)
Credit facility – letters of credit	(708)
Total	**$2,755**

Approximately $2.8 billion of liquidity at AR <u>pro forma for equity offering shoe exercise</u> plus an additional $3.0 billion of AM units

Antero Midstream (NYSE:AM)

6/30/2016 Debt

Debt Type	$MM
Credit facility	$760
Total	**$760**

Liquid Assets

Asset Type	$MM
Cash	$9
Total	**$9**

Only 51% of AM credit facility capacity drawn

Liquidity

Asset Type	$MM
Cash	$9
Credit facility – capacity	1,500
Credit facility – drawn	(760)
Credit facility – letters of credit	-
Total	**$749**

Approximately $750 million of liquidity at AM

Note: All balance sheet data as of 6/30/2016. Antero Resources pro forma for $85 million net proceeds from shoe exercise and $546 million cost of pending acreage acquisition including tag along right less $45 million deposit.

1. *Mark-to-market as of 6/30/2016.*
2. *Based on AR ownership of AM units (108.3 million common and subordinated units as of 9/2/2016) and AM's closing price as of 6/30/2016.*
3. *AR credit facility commitments of $4.0 billion, borrowing base of $4.5 billion.*

Antero Midstream (NYSE: AM) Asset Overview

MLP (NYSE: AM) HIGHLIGHTS SUBSTANTIAL VALUE IN MIDSTREAM BUSINESS

Corporate Structure Overview

Public

Antero Resources Corporation (NYSE: AR)
$11.9 Billion Enterprise Value(1)
Ba2/BB Corporate Rating

39% LP Interest
$1.9 Billion MV

61% LP Interest
$3.0 Billion MV

Antero Midstream Partners LP (NYSE: AM)
$5.7 Billion Enterprise Value

Gathering/Compression Assets

Water Infrastructure Assets

$2.1 Bn MTM Hedge Position(2)

$12.7 Bn 3P PV-10(3) E&P Assets

MLP Benefits:
- Funding vehicle to expand midstream business
- Highlights value of Antero Midstream
- Liquid asset for Antero Resources

Market Valuation of AR Ownership in AM:

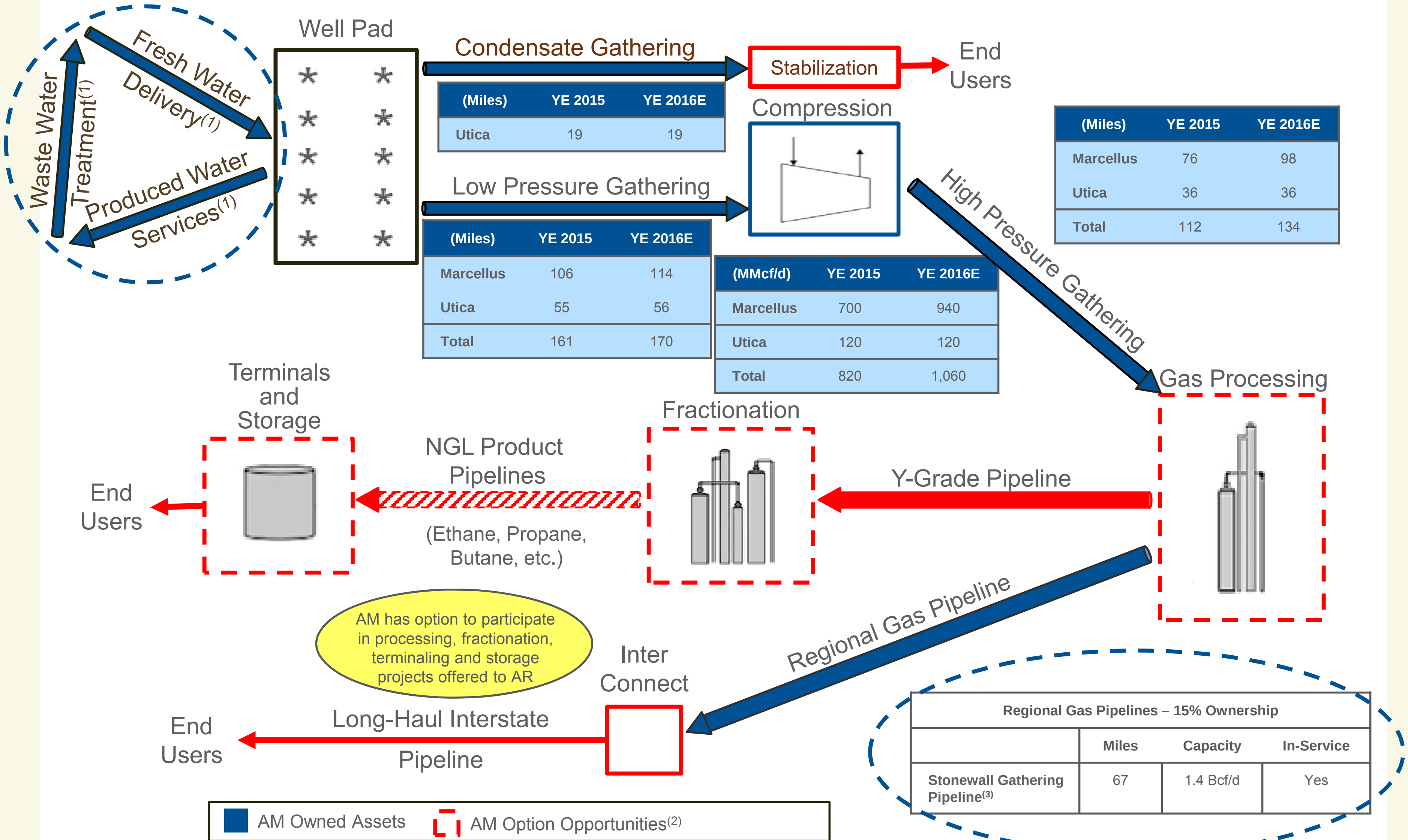
- AR ownership: 61% LP Interest = 108.3 million units

AM Price per Unit	AM Units Owned by AR (MM)	AR Value in AM LP Units ($MMs)	Value Per AR Share(4)
$23	109	$2,505	$8
$24	109	$2,614	$9
$25	109	$2,723	$9
$26	109	$2,831	$9
$27	109	$2,940	$10
$28	**109**	**$3,059**	**$10**
$29	109	$3,161	$10

1. *AR enterprise value includes market value of AR stock and AR net debt only. Market values (MV) as of 6/30/2016 and includes subordinated units; balance sheet data as of 6/30/2016.* ***Pro forma for $85 million net proceeds from shoe exercise and $546 million cost of pending acreage acquisition including tag along right adjusted for $45 million deposit.***
2. *3.4 Tcfe hedged at $3.71/Mcfe average price through 2022 with mark-to-market (MTM) value of $2.1 billion as of 6/30/2016.*
3. *3P pre-tax PV-10 based on annual strip pricing for first 10-years and flat thereafter as of December 31, 2015. NGL pricing assumes 39%, 46% and 48% of WTI strip prices for 2016, 2017 and 2018 and thereafter, respectively.* ***Includes unaudited $1.5 billion 3P PV-10 from pending acreage acquisition per press release dated 6/9/2016 and exercise of tag along right.***
4. *Based on 307.2 million AR shares outstanding pro forma for 3.0 million share shoe exercise, and 176.6 million AM units outstanding as of 9/2/2016.*

AM'S FULL VALUE CHAIN BUSINESS MODEL

AM recently exercised its option on 15% interest in Stonewall, adding a regional gas gathering pipeline to its portfolio



Condensate Gathering

(Miles)	YE 2015	YE 2016E
Utica	19	19

Low Pressure Gathering

(Miles)	YE 2015	YE 2016E
Marcellus	106	114
Utica	55	56
Total	161	170

Compression

(MMcf/d)	YE 2015	YE 2016E
Marcellus	700	940
Utica	120	120
Total	820	1,060

High Pressure Gathering

(Miles)	YE 2015	YE 2016E
Marcellus	76	98
Utica	36	36
Total	112	134

Regional Gas Pipelines – 15% Ownership			
	Miles	Capacity	In-Service
Stonewall Gathering Pipeline(3)	67	1.4 Bcf/d	Yes

1. *Acquired by AM from AR for a $1.05 billion upfront payment and a $125 million earn out in each of 2019 and 2020.*
2. *Antero Midstream has a right of first offer on 220,000 dedicated net acres for processing and fractionation pro forma for pending third-party acreage acquisition.*
3. *Antero Midstream owns 15% stake in Stonewall pipeline.*

ANTERO MIDSTREAM GATHERING AND COMPRESSION ASSET OVERVIEW

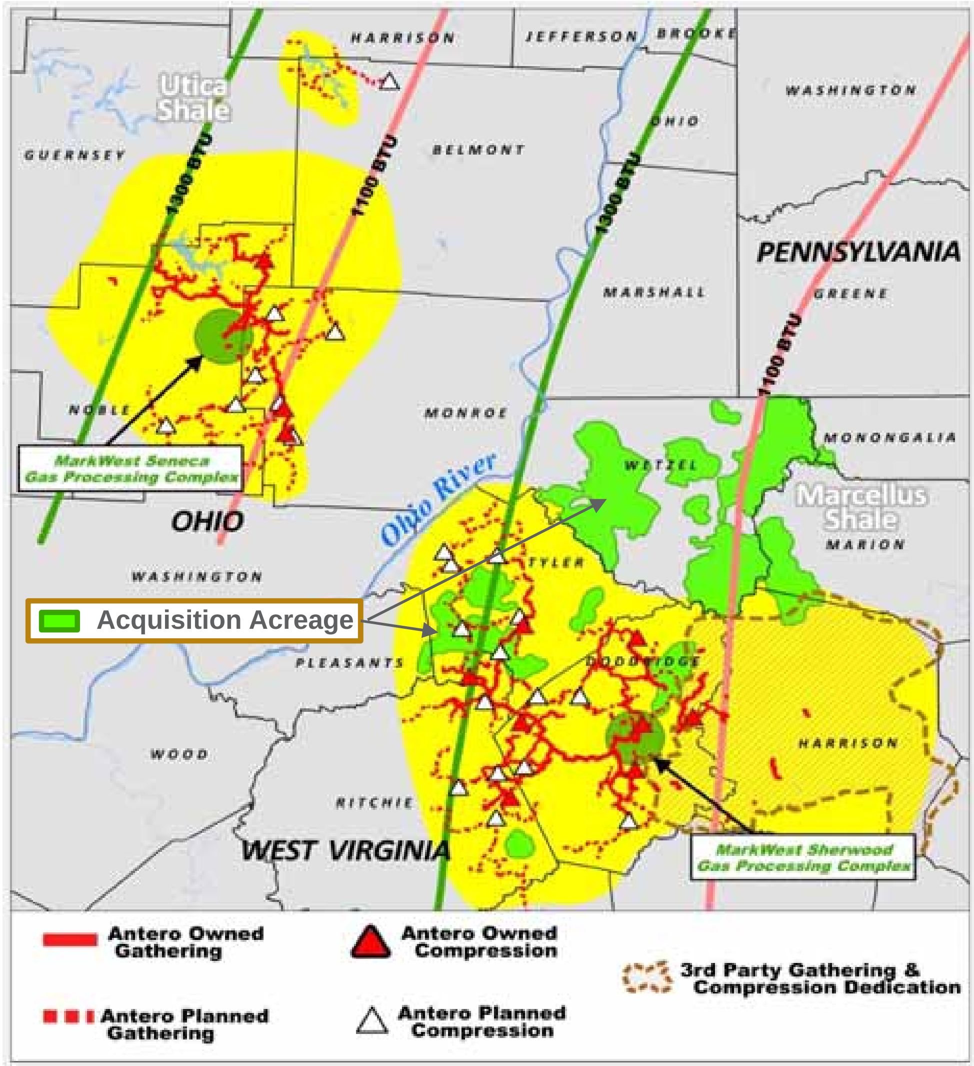
Antero Midstream Partners LP

Gathering and Compression Assets

- Gathering and compression assets in core of rapidly growing Marcellus and Utica Shale plays
  - Acreage dedication of ~576,000 gross leasehold acres for gathering and compression services
  - Additional stacked pay potential with dedication on ~278,000 gross acres of Utica deep rights underlying the Marcellus in WV and PA
  - 100% fixed fee long term contracts
- AR owns 61% of AM units (NYSE: AM)

Projected Gathering and Compression Infrastructure[1]

	Marcellus Shale	Utica Shale	Total
YE 2015 Cumulative Gathering/ Compression Capex ($MM)	**$981**	**$462**	**$1,443**
Gathering Pipelines (Miles)	182	91	273
Compression Capacity (MMcf/d)	700	120	820
Condensate Gathering Pipelines (Miles)	-	19	19
2016E Gathering/Compression Capex Budget ($MM)[2]	**$235**	**$20**	**$255**
Gathering Pipelines (Miles)	30	1	31
Compression Capacity (MMcf/d)	240	-	240
Condensate Gathering Pipelines (Miles)	-	-	-



1. Represents inception to date actuals as of 12/31/2015 and 2016 guidance.
2. Includes both expansion capital and maintenance capital.

ANTERO MIDSTREAM WATER BUSINESS OVERVIEW

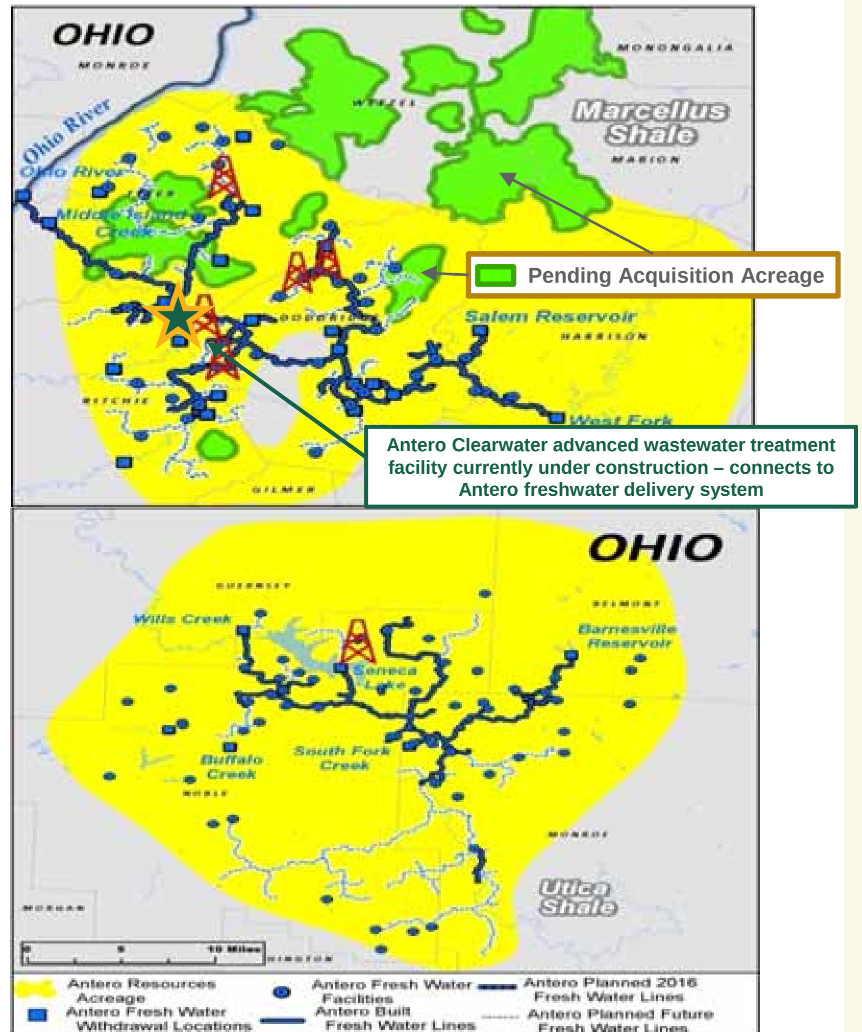
- AM acquired AR's integrated water business for $1.05 billion plus earn out payments of $125 million at year-end in each of 2019 and 2020
  - The acquired business includes Antero's Marcellus and Utica freshwater delivery business, the fully-contracted future advanced wastewater treatment complex and all fluid handling and disposal services for Antero

Water Business Assets

- Fresh water delivery assets provide fresh water to support Marcellus and Utica well completions
  - Year-round water supply sources: Clearwater Facility, Ohio River, local rivers & reservoirs[2]
  - 100% fixed fee long term contracts

Projected Water Business Infrastructure[1]

	Marcellus Shale	Utica Shale	Total
YE 2015 Cumulative Fresh Water Delivery Capex ($MM)	**$469**	**$62**	**$531**
Water Pipelines (Miles)	184	75	259
Fresh Water Storage Impoundments	22	13	35
2016E Fresh Water Delivery Capex Budget ($MM)[3]	**$40**	**$10**	**$50**
Water Pipelines (Miles)	20	9	29
Fresh Water Storage Impoundments	1	-	1
Cash Operating Margin per Well[4]	**$950k - $1,050k**	**$825k - $925k**	
2016E Advanced Waste Water Treatment Budget ($MM)			**$130**
2016E Total Water Business Budget ($MM)			**$180**

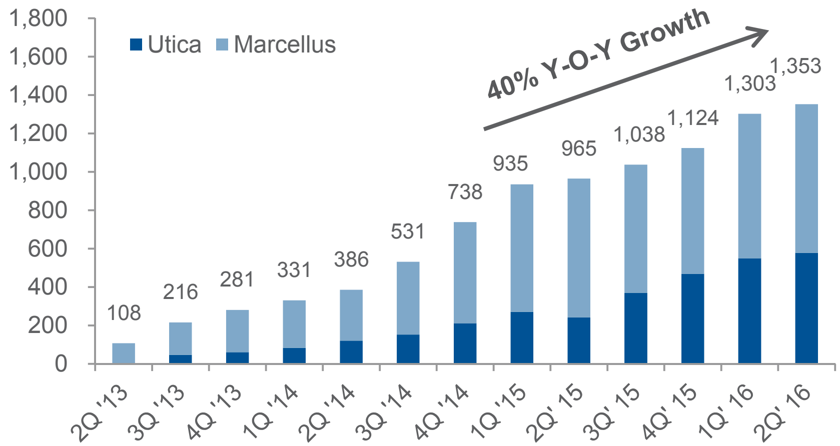


Note: Antero acreage position reflects tax districts in which greater than 3,000 net acres are owned.

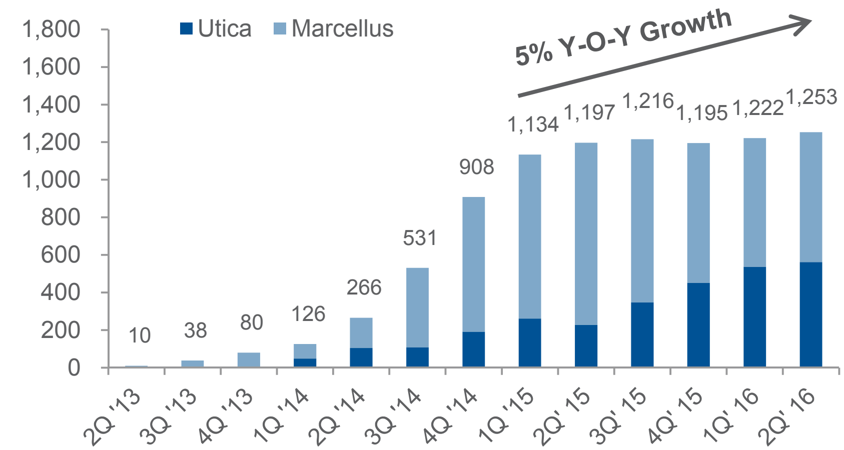
1. *Represents inception to date actuals as of 12/31/2015 and 2016 guidance.*
2. *All Antero water withdrawal sites are fully permitted under long-term state regulatory permits both in WV and OH.*
3. *Includes both expansion capital and maintenance capital.*
4. *Marcellus assumes fee of $3.69 per barrel subject to annual inflation and 38 barrels of water per lateral foot that utilize the fresh water delivery system based on 9,000 foot lateral. Operating margin excludes G&A. Utica assumes fee of $3.64 per barrel subject to annual inflation and 34 barrels of water per lateral foot that utilize the fresh water delivery system based on 9,000 foot lateral. Water volumes assume 5% recycling. Operating margin excludes G&A.*

HIGH GROWTH MIDSTREAM THROUGHPUT

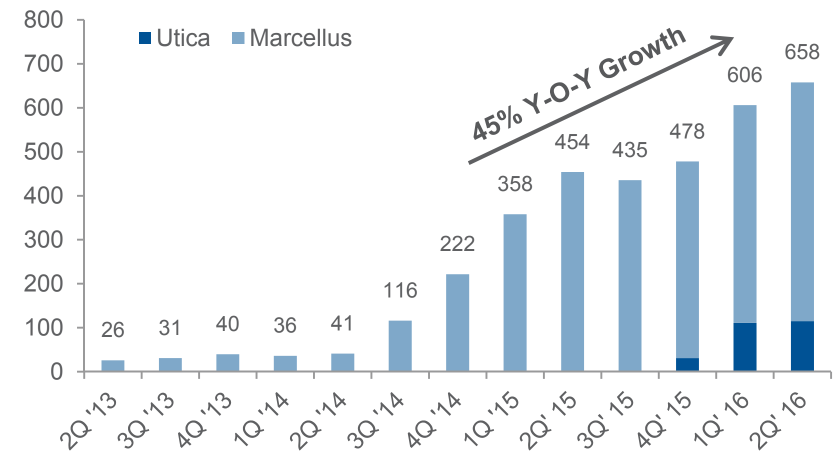
Low Pressure Gathering (MMcf/d)



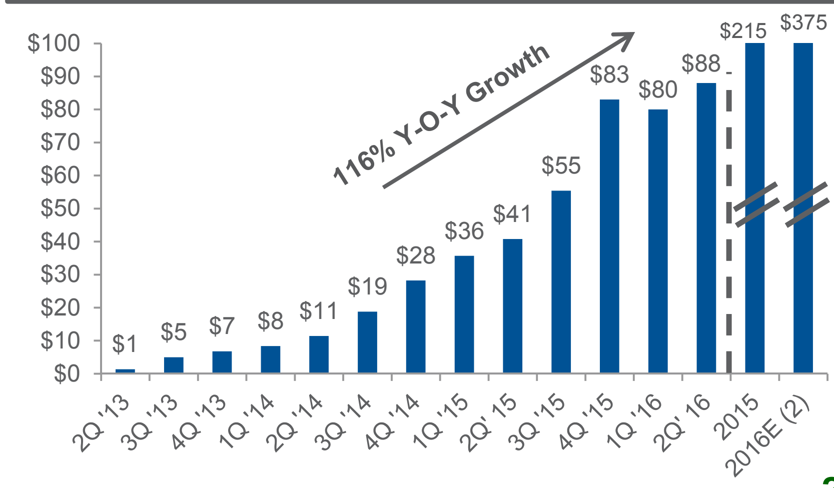
High Pressure Gathering (MMcf/d)



Compression (MMcf/d)



EBITDA ($MM)



Note: Y-O-Y growth based on 2Q'15 to 2Q'16 for throughput and 1Q'15 to 1Q'16 for EBITDA.
1. Represents midpoint of updated 2016 guidance.

KEY CATALYSTS FOR ANTERO

1 Production and Cash Flow Growth	Guiding to production growth of 20% in 2016 and targeting 20% to 25% in 2017, with 94% of forecasted production hedged through 2018 at $3.81/MMBtu, a $0.76 premium to strip
2 Continued Operational Improvement	33% lower well cost per 1,000’ lateral and 33% higher EUR per 1,000’ since 2014 are driving rates of return significantly higher despite lower strip pricing
3 Sustainability of Antero’s Integrated Business Model	Large, low unit cost core Marcellus and Utica natural gas drilling inventory with associated liquids generates attractive returns supported by long-term natural gas hedges, takeaway portfolio and downstream LNG and NGL sales agreements
4 Exposure to Commodity Upside	Most active developer in the lowest cost basin with growing production base and firm transport to favorable markets; over 38 Tcfe of unhedged 3P reserves increase ~$10 billion in pre-tax PV-10 value with a 50% recovery in commodity prices
5 Midstream MLP Growth	Antero owns 61% of Antero Midstream Partners and thereby participates directly in its growth and value creation; acquisition of integrated water business from Antero expected to result in distributable cash flow per unit accretion in 2016
6 Consolidation	Antero is well positioned to continue to be a leading consolidator in Appalachia

APPENDIX

ANTERO CAPITALIZATION – CONSOLIDATED

($ in millions)	6/30/2016	Pro Forma[4] 6/30/2016
Cash	$28	$28
AR Senior Secured Revolving Credit Facility	140	556
AM Bank Credit Facility	760	760
6.00% Senior Notes Due 2020	525	525
5.375% Senior Notes Due 2021	1,000	1,000
5.125% Senior Notes Due 2022	1,100	1,100
5.625% Senior Notes Due 2023	750	750
Net Unamortized Premium	6	6
Total Debt	$4,281	$4,697
Net Debt	$4,253	$4,669
Financial & Operating Statistics		
LTM EBITDAX[1]	$1,287	$1,287
LTM Interest Expense[2]	$250	$250
Proved Reserves (Bcfe) (12/31/2015)	13,215	13,215
Proved Developed Reserves (Bcfe) (12/31/2015)	5,838	5,838
Credit Statistics		
Net Debt / LTM EBITDAX	3.3x	3.6x
Net Debt / Net Book Capitalization	36%	38%
Net Debt / Proved Developed Reserves ($/Mcfe)	$0.73	$0.80
Net Debt / Proved Reserves ($/Mcfe)	$0.32	$0.35
Liquidity		
Credit Facility Commitments[3]	$5,500	$5,500
Less: Borrowings	(900)	(1,316)
Less: Letters of Credit	(708)	(708)
Plus: Cash	28	28
Liquidity (Credit Facility + Cash)	**$3,920**	**$3,504**

AR LISTED NYSE

AM LISTED NYSE

1. *LTM and 6/30/2016 EBITDAX reconciliation provided below.*
2. *LTM interest expense adjusted for all capital market transactions since 1/1/2015.*
3. *AR lender commitments under the facility increased to $4.0 billion from $3.0 billion on 2/17/2015; borrowing base capacity reaffirmed at $4.5 billion in April 2016 following Spring redetermination. AM credit facility increased to $1.5 billion concurrent with water drop down on 9/23/2015.*
4. *Pro forma for $85 million net proceeds from shoe exercise and $546 million cost of pending acreage acquisition including tag along right adjusted for $45 million deposit paid.*

ANTERO RESOURCES – UPDATED 2016 GUIDANCE

Key Operating & Financial Assumptions

Key Variable	Updated 2016 Guidance[1]	Previous 2016 Guidance
Net Daily Production (MMcfe/d)	**1,800**	**1,750**
Net Residue Natural Gas Production (MMcf/d)	1,365	1,355
Net C3+ NGL Production (Bbl/d)	53,500	52,500
Net Ethane Production (Bbl/d)	15,000	10,000
Net Oil Production (Bbl/d)	4,500	3,500
Net Liquids Production (Bbl/d)	73,000	66,000
Natural Gas Realized Price <u>Premium</u> to NYMEX Henry Hub Before Hedging ($/Mcf)[2][3]	+$0.00 to $0.05	+$0.00 to $0.10
Oil Realized Price Differential to NYMEX WTI Oil Before Hedging ($/Bbl)	$(10.00) - $(11.00)	$(10.00) - $(11.00)
C3+ NGL Realized Price (% of NYMEX WTI)[2]	35% - 40%	35% - 40%
Ethane Realized Price (Differential to Mont Belvieu) ($/Gal)	$0.00	$0.00
<u>Operating:</u>		
Cash Production Expense ($/Mcfe)[4]	$1.40 - $1.50	$1.50 - $1.60
Marketing Expense, Net of Marketing Revenue ($/Mcfe)	$0.15 - $0.20	$0.15 - $0.20
G&A Expense ($/Mcfe)	$0.20 - $0.22	$0.20 - $0.25
Operated Wells Completed	110	110
Drilled Uncompleted Wells	70	70
Average Operated Drilling Rigs	≈ 7	≈ 7
<u>Capital Expenditures ($MM):</u>		
Drilling & Completion	$1,300	$1,300
Land	$100	$100
Total Capital Expenditures ($MM)	**$1,400**	**$1,400**

1. Updated guidance per press release dated 09/06/2016.
2. Based on current strip pricing as of August 30, 2016.
3. Includes Btu upgrade as Antero's processed tailgate and unprocessed dry gas production is greater than 1000 Btu on average.
4. Includes lease operating expenses, gathering, compression and transportation expenses and production taxes.

ANTERO MIDSTREAM – UPDATED 2016 GUIDANCE

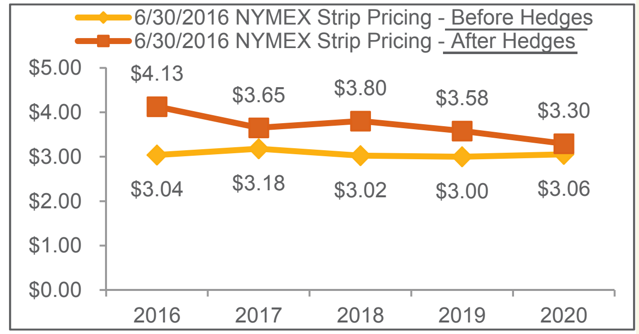
Key Operating & Financial Assumptions

Key Variable	Updated 2016 Guidance[1]	Previous 2016 Guidance
Financial:		
Net Income ($MM)	$205 - $225	$165 - $190
Adjusted EBITDA ($MM)	$365 - $385	$325 - $350
Distributable Cash Flow ($MM)	$315 - $335	$275 - $300
Year-over-Year Distribution Growth	30%	30%
Operating:		
Low Pressure Pipeline Added (Miles)	9	9
High Pressure Pipeline Added (Miles)	22	22
Compression Capacity Added (MMcf/d)	240	240
Fresh Water Pipeline Added (Miles)	30	30
Capital Expenditures ($MM):		
Gathering and Compression Infrastructure	$240	$240
Fresh Water Infrastructure	$40	$40
Advanced Wastewater Treatment	$130	$130
Stonewall Gathering Pipeline Option	$45	$45
Maintenance Capital	$25	$25
Total Capital Expenditures ($MM)	$480	$480

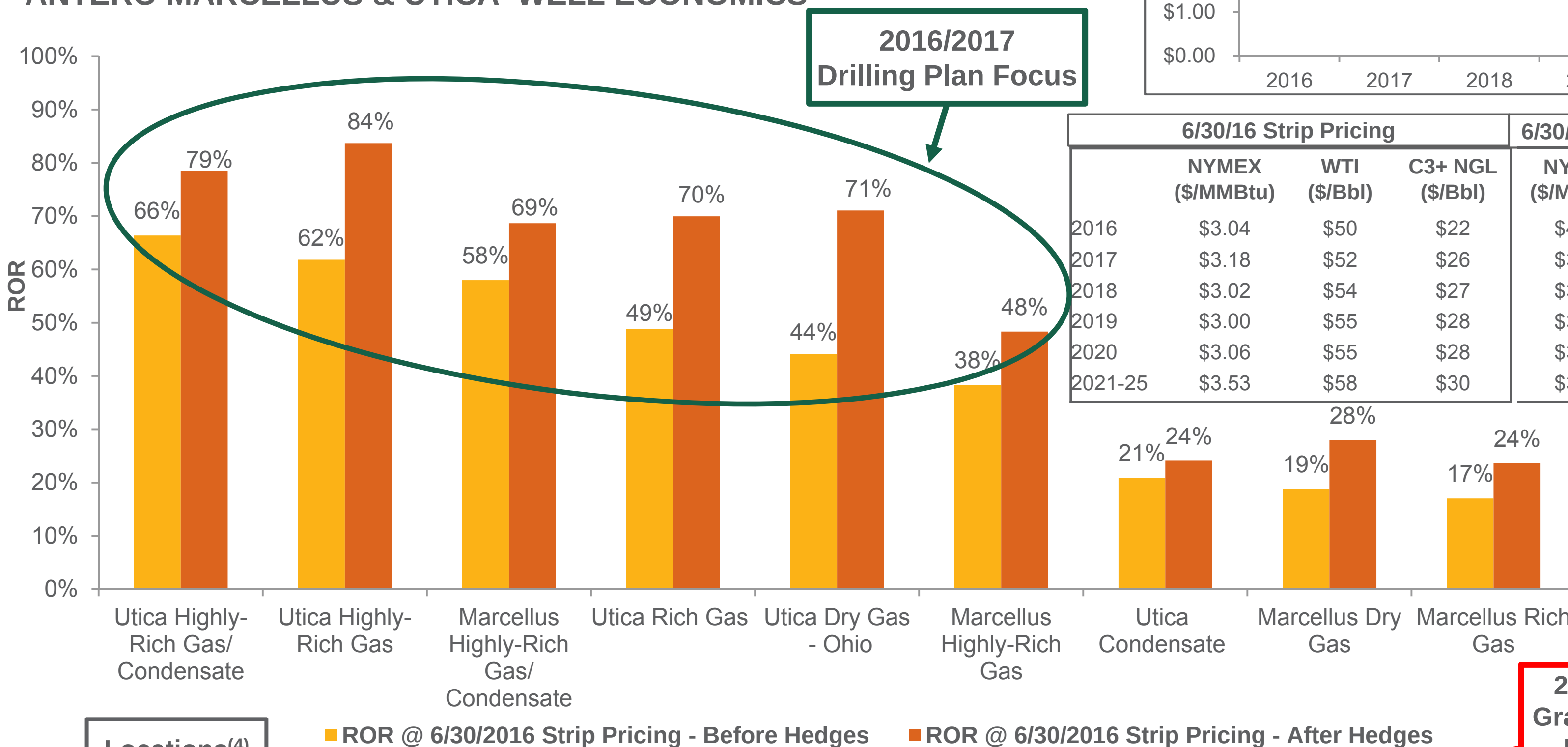
1. Updated guidance per press release dated 09/06/2016.

SUSTAINABLE BUSINESS MODEL

- At 6/30/2016 strip pricing, Antero has 2,713 locations with well economics that exceed 20% rate of return (excluding hedges), pro forma for third-party acquisition
  - *Including hedges, these locations generate rates of return of approximately 48% to 84%*
- Rates of return include pad, facilities, cash production expenses (including midstream and FT costs)
  - *See assumptions pages in appendix for further detail*



ANTERO MARCELLUS & UTICA WELL ECONOMICS(1)(2)(3)



	6/30/16 Strip Pricing			6/30/16 Hedge Pricing	
	NYMEX ($/MMBtu)	WTI ($/Bbl)	C3+ NGL ($/Bbl)	NYMEX ($/MMBtu)	C3+ NGL ($/Bbl)
2016	$3.04	$50	$22	$4.13	$24
2017	$3.18	$52	$26	$3.65	$21
2018	$3.02	$54	$27	$3.80	$28
2019	$3.00	$55	$28	$3.58	$28
2020	$3.06	$55	$28	$3.30	$28
2021-25	$3.53	$58	$30	$3.56	$30

2,713 "High Grade" Drilling Locations

Locations(4)								
98	108	664	161	263	1,235	184	940	691

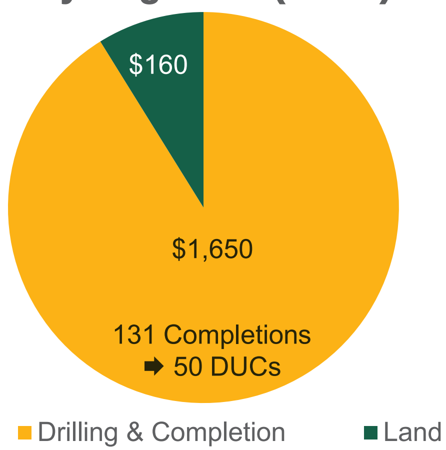
1. *6/30/2016 pre-tax well economics based on a 9,000' lateral, 6/30/2016 natural gas and WTI strip pricing for 2016-2024, flat thereafter, NGLs at 37.5% of WTI for 2016 and ~50% of WTI thereafter, and applicable firm transportation and operating costs including 50% of Antero Midstream fees. Well cost estimates include $1.2 million for road, pad and production facilities.*
2. *ROR @ 6/30/2016 Strip Pricing – After Hedges reflects 6/30/2016 well cost ROR methodology with the 6/30/2016 hedge value allocated based on 2016-2021 projected production volumes resulting in blend of strip and hedge prices.*
3. *Marcellus well count, adjusted for 6/30/2016 net acreage and pro forma for third-party acquisition per press release dated 6/9/2016, assumes 1.7 Bcf/1,000' type curve.*
4. *Undeveloped well locations as of 12/31/2015 adjusted for 6/30/2016 acreage changes.*

2016 CAPITAL BUDGET

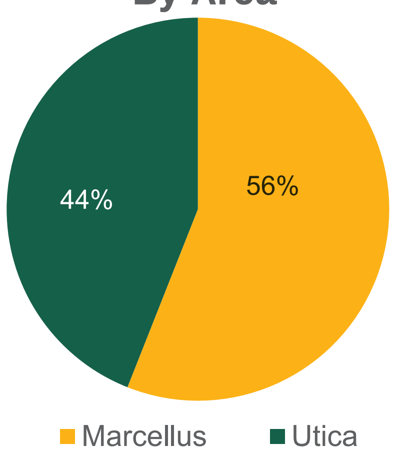
- Antero's 2016 initial capital budget is $1.4 billion, a 23% decrease from 2015 capital expenditures of $1.8 billion and a 58% decline from 2014 capital expenditures

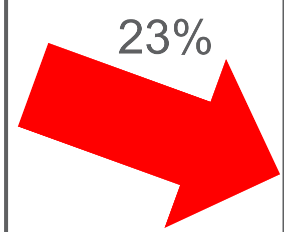
$1.8 Billion – 2015[1]

By Segment ($MM)



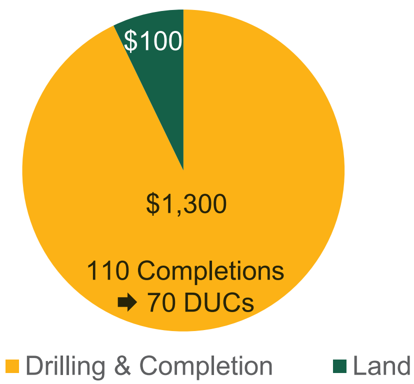
By Area



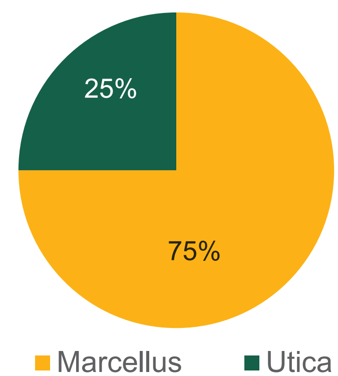


$1.4 Billion – 2016

By Segment ($MM)



By Area

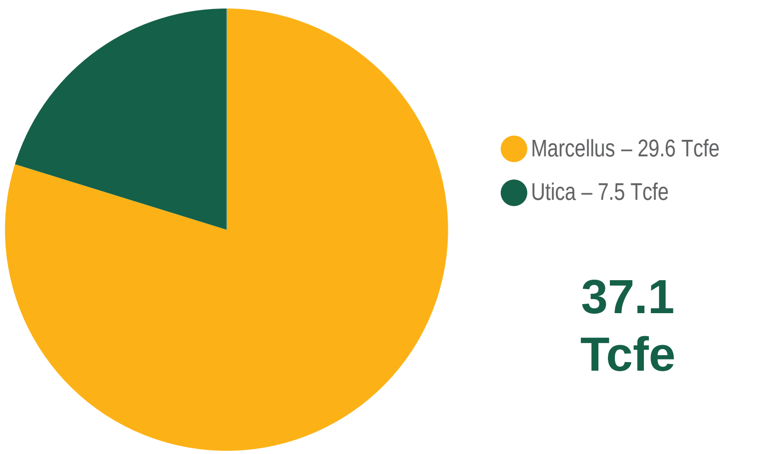


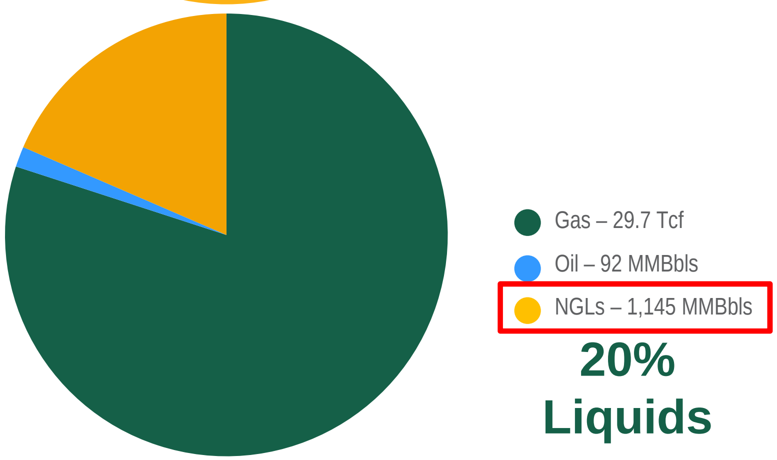
1. *Excludes $39 million for leasehold acquisitions in 2015. DUCs are drilled but uncompleted wells at year-end.*

CONSIDERABLE RESERVE BASE WITH ETHANE OPTIONALITY

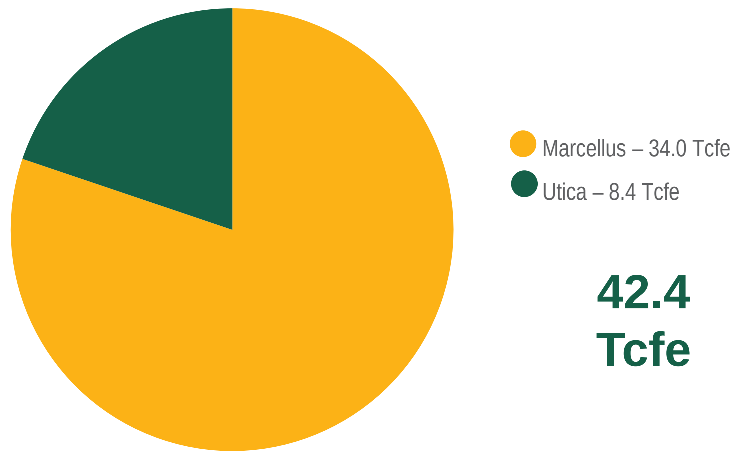
- 27 year proved reserve life based on 2015 production annualized
- Reserve base provides significant exposure to liquids-rich projects
  - *3P reserves of over 2.4 BBbl of NGLs and condensate in ethane recovery mode; 35% liquids*
  - *Incudes 1.2 BBbl of ethane*

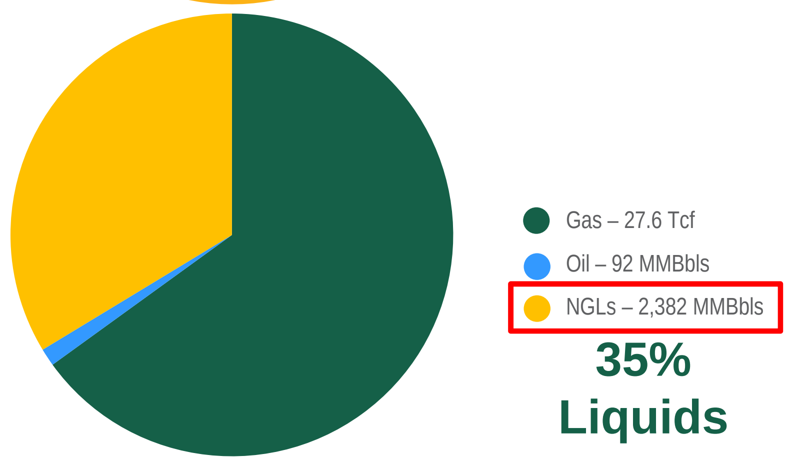
ETHANE REJECTION[(1)(2)]





ETHANE RECOVERY[(1)]





1. *Ethane rejection occurs when ethane is left in the wellhead gas stream as the gas is processed, rather than being separated out and sold as a liquid after fractionation. When ethane is left in the gas stream, the BTU content of the residue gas at the outlet of the processing plant is higher. Producers will elect to "reject" ethane when the price received for the higher BTU residue gas is greater than the price received for the ethane being sold as a liquid after fractionation. When ethane is recovered, the BTU content of the residue gas is lower, but a producer is then able to recover the value of the ethane sold as a separate NGL product.*
2. *1.1 Tcfe of ethane reserves (182 million barrels) was included in 12/31/2015 reserves from the Marcellus Shale as the first de-ethanizer was placed online at the MarkWest Sherwood facility in December 2015 and Antero's first ethane sales contract is expected to commence in 2017 upon the completion of Mariner East 2.* ***Not pro forma for pending acreage acquisition.***

ETHANE RECOVERY ECONOMICS AND POTENTIAL VOLUMES

RECOVERING ETHANE: ARBITRAGE VS. NATURAL GAS PRICING

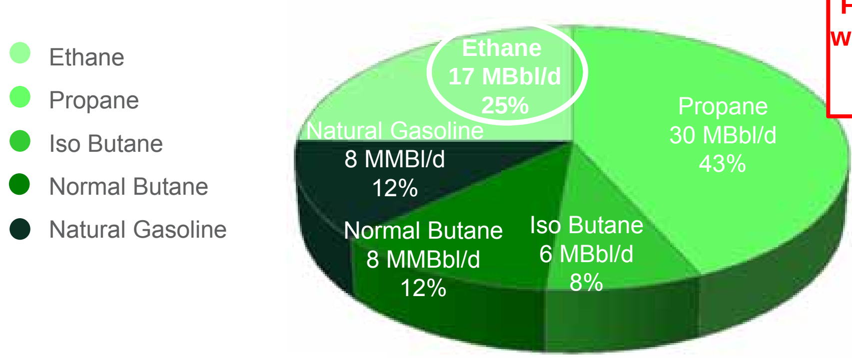
Example C2 Recovery Decision

	Assuming $3.00/MMBtu Natural Gas		
	$ / MMBtu	C2 Conversion Factor	$/Gal
Natural Gas Price	$3.00		
Less: Variable Transport Costs	(0.08)		
Less: July TCO Differential	(0.15)		
Realized Pricing	$2.77	15.175	$0.18
Plus: De-Ethanization Fee			0.05
Required Ethane Price to Recover (ATEX Sunk)			**$0.23**
Plus: New Ethane Transportation			0.15
Required Ethane Price to Recover (New Transportation)			**$0.38**

Assuming ATEX costs are sunk and NYMEX gas prices are $3.00/MMBtu, ethane would need to be at least $0.23 per gallon for Antero to recover ethane (up to its 20 MBbl/d ATEX Commitment)

Assuming incremental ethane transport costs $0.15/gallon and NYMEX gas prices are $3.00/MMBtu, ethane price would need to be at least $0.38/gallon for Antero to recover ethane above its 20 MBbl/d ATEX commitment and 11.5 MBbl/d Borealis firm sale

2Q 2016 NGL PRODUCTION (PARTIAL C2 RECOVERY)

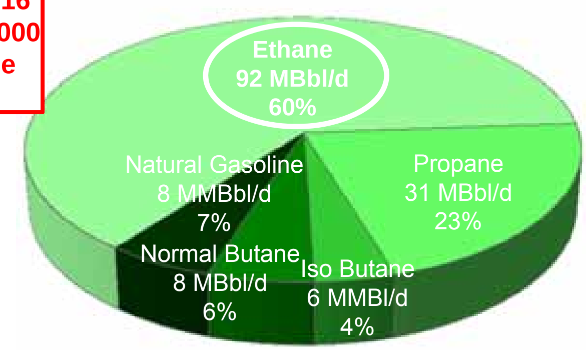


	% of C2+ Bbl
Ethane	25%
Propane	43%
Iso Butane	8%
Normal Butane	12%
Natural Gasoline	12%
Total	**100%**

70 MBbl/d 2Q 2016 C2+ Actual Production

2Q 2016 NGL PRODUCTION (FULL C2 RECOVERY)

Full C2 Recovery in Q2 2016 would have resulted in 75,000 Bbl/d of additional ethane production



	% of C2+ Bbl
Ethane	63%
Propane	21%
Iso Butane	4%
Normal Butane	6%
Natural Gasoline	6%
Total	**100%**

145 MBbl/d 2Q 2016 C2+ Potential Production

1. Incremental ethane transport cost assumed to be $0.15/gallon. For illustrative purposes only.

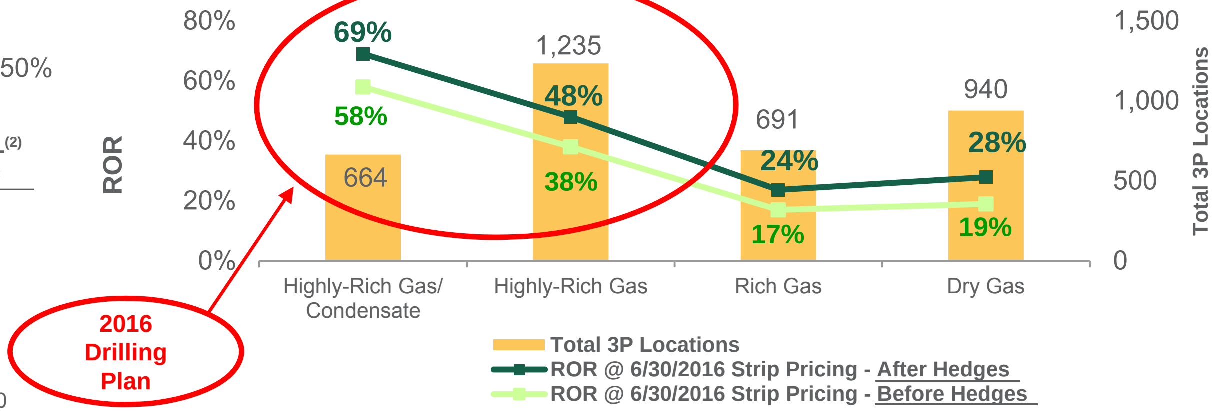
MARCELLUS SINGLE WELL ECONOMICS – IN ETHANE REJECTION

Assumptions

- Natural Gas – 6/30/2016 strip
- Oil – 6/30/2016 strip
- NGLs – 37.5% of Oil Price 2016; ~50% of Oil Price 2017+

	NYMEX ($/MMBtu)	WTI ($/Bbl)	C3+ NGL[2] ($/Bbl)
2016	$3.04	$50	$22
2017	$3.18	$52	$26
2018	$3.02	$54	$27
2019	$3.00	$55	$28
2020	$3.06	$55	$28
2021-25	$3.19-$3.88	$56-$59	$29-$30

Marcellus Well Economics and Total Gross Locations[1]



Classification	Highly-Rich Gas/ Condensate	Highly-Rich Gas	Rich Gas	Dry Gas
Modeled BTU	**1313**	**1250**	**1150**	**1050**
EUR (Bcfe):	20.8	18.8	16.8	15.3
EUR (MMBoe):	3.5	3.1	2.8	2.6
% Liquids:	33%	24%	12%	0%
Lateral Length (ft):	9,000	9,000	9,000	9,000
Well Cost ($MM):	$8.1	$8.1	$8.1	$8.1
Bcfe/1,000’:	2.3	2.1	1.9	1.7
Net F&D ($/Mcfe):	$0.46	$0.51	$0.57	$0.62
Direct Operating Expense ($/well/month):	$1,498	$1,498	$1,498	$1,498
Direct Operating Expense ($/Mcf):	$0.92	$0.92	$1.17	$0.70
Transportation Expense ($/Mcf):	$0.28	$0.28	$0.28	$0.28
Pre-Tax NPV10 ($MM):	$12.3	$8.2	$2.2	$2.8
Pre-Tax ROR:	58%	38%	17%	19%
Payout (Years):	1.5	2.1	5.4	4.7
Gross 3P Locations in BTU Regime[3]:	664	1,235	691	940

1. *6/30/2016 pre-tax well economics based on 1.7 Bcf/1,000’ type curve for a 9,000’ lateral, 6/30/2016 natural gas and WTI strip pricing for 2016-2025, flat thereafter, NGLs at 37.5% of WTI for 2016 and ~50% of WTI thereafter, and applicable firm transportation and operating costs including 50% of Antero Midstream fees. Well cost estimates include $1.2 million for road, pad and production facilities.*
2. *Pricing for a 1225 BTU y-grade ethane rejection barrel. NGLs at 37.5% of WTI for 2016 and ~50% of WTI for 2017 and thereafter. NGL prices are forecast to increase in 2017 relative to WTI due to projected in-service date of Mariner East 2 project allowing for a significant increase in AR NGL exports via ship.*
3. *Undeveloped well locations as of 12/31/2015 adjusted for 6/30/2016 net acreage and pro forma for 625 added through third-party pending acreage acquisition.*

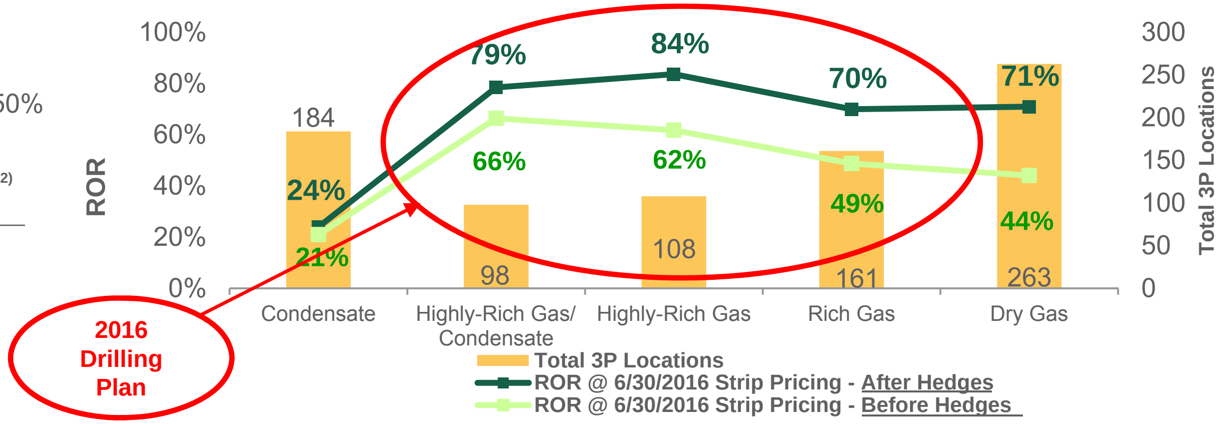
UTICA SINGLE WELL ECONOMICS – IN ETHANE REJECTION

Assumptions

- Natural Gas – 6/30/2016 strip
- Oil – 6/30/2016 strip
- NGLs – 37.5% of Oil Price 2016; ~50% of Oil Price 2017+

	NYMEX ($/MMBtu)	WTI ($/Bbl)	C3+ NGL[2] ($/Bbl)
2016	$3.04	$50	$22
2017	$3.18	$52	$26
2018	$3.02	$54	$27
2019	$3.00	$55	$28
2020	$3.06	$55	$28
2021-25	$3.19-$3.88	$56-$59	$29-$30

Utica Well Economics and Gross Locations[1]



Classification	Condensate	Highly-Rich Gas/ Condensate	Highly-Rich Gas	Rich Gas	Dry Gas
Modeled BTU	**1275**	**1235**	**1215**	**1175**	**1050**
EUR (Bcfe):	9.4	17.0	25.3	23.8	21.4
EUR (MMBoe):	1.6	2.8	4.2	4.0	3.6
% Liquids	35%	26%	21%	14%	0%
Lateral Length (ft):	9,000	9,000	9,000	9,000	9,000
Well Cost ($MM):	$9.4	$9.4	$9.9	$9.9	$9.9
Bcfe/1,000':	1.0	1.9	2.8	2.7	2.4
Net F&D ($/Mcfe):	$1.23	$0.68	$0.48	$0.51	$0.57
Fixed Operating Expense ($/well/month):	$2,788	$2,788	$2,788	$2,788	$1,498
Direct Operating Expense ($/Mcf):	$0.99	$0.99	$0.99	$0.99	$0.50
Direct Operating Expense ($/Bbl):	$2.73	$2.73	$2.73	-	-
Transportation Expense ($/Mcf):	$0.55	$0.55	$0.55	$0.55	$0.55
Pre-Tax NPV10 ($MM):	$3.4	$11.6	$13.2	$10.7	$9.5
Pre-Tax ROR:	21%	66%	62%	49%	44%
Payout (Years):	4.2	1.6	1.7	2.0	2.2
Gross 3P Locations in BTU Regime[3]:	184	98	108	161	263

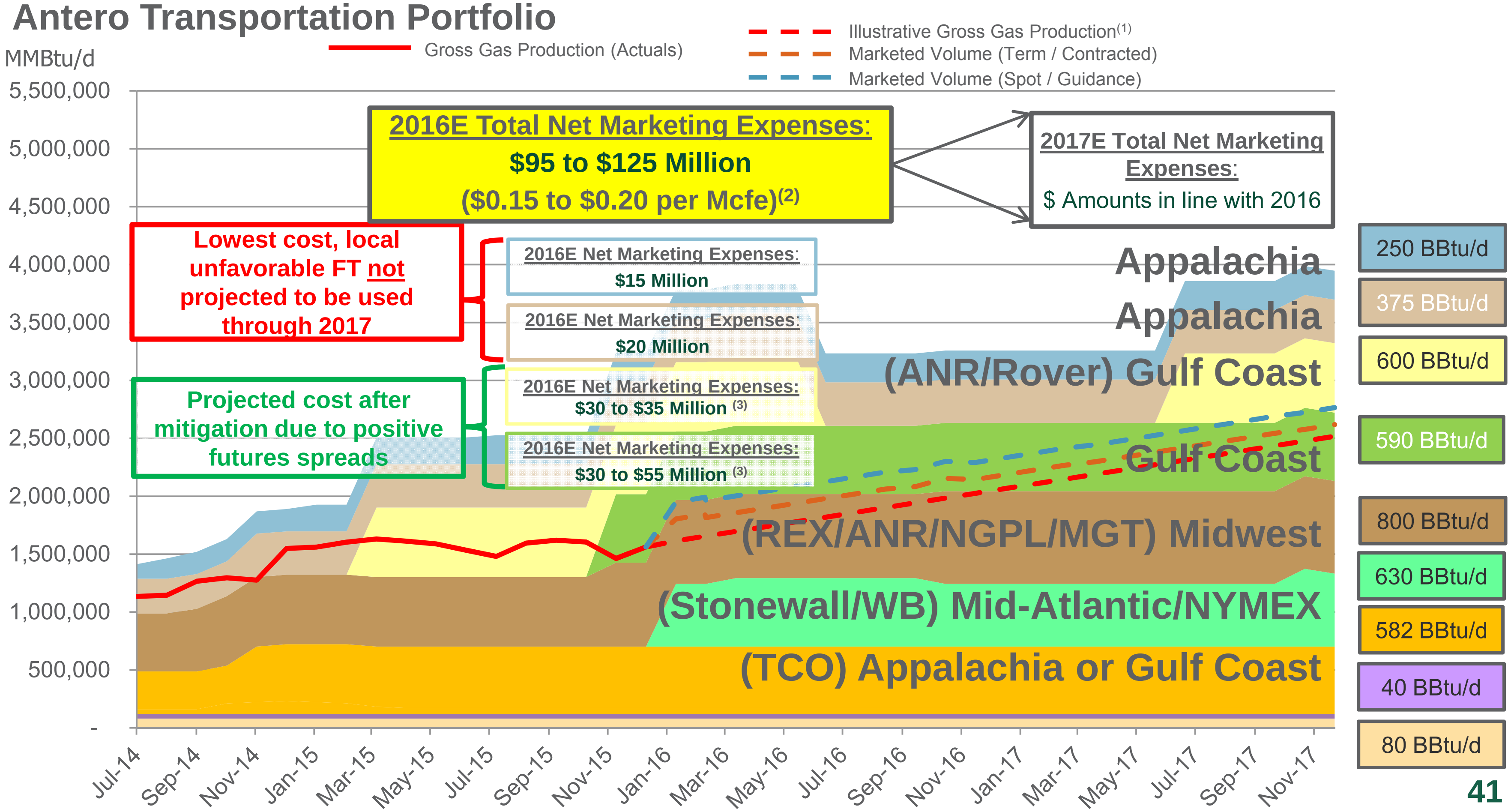
1. *6/30/2016 pre-tax well economics based on a 9,000' lateral, 6/30/2016 natural gas and WTI strip pricing for 2016-2025, flat thereafter, NGLs at 37.5% of WTI for 2016 and ~50% of WTI thereafter, and applicable firm transportation and operating costs including 50% of Antero Midstream fees. Well cost estimates include $1.2 million for road, pad and production facilities.*
2. *Pricing for a 1225 BTU y-grade ethane rejection barrel. NGLs at 37.5% of WTI for 2016 and ~50% of WTI for 2017 and thereafter. NGL prices are forecast to increase in 2017 relative to WTI due to projected in-service date of Mariner East 2 project allowing for a significant increase in AR NGL exports via ship.*
3. *Undeveloped well locations as of 12/31/2015. 3P locations representative of BTU regime; EUR and economics within regime will vary based on BTU content.*

FIRM TRANSPORTATION AND SALES PORTFOLIO

- While Antero has excess FT in place through 2017, the expected cost of unutilized FT is estimated to be modest at well under 10% of EBITDA

Columbia 7/26/2009 – 9/30/2025	**Stonewall/Tennessee** 11/1/2015– 9/30/2030	**Momentum III** 9/1/2012 – 12/31/2023	**EQT** 8/1/2012 – 6/30/2025	**REX/MGT/ANR** 7/1/2014 – 12/31/2034
ANR 3/1/2015– 2/28/2045	**Stonewall/WB** 11/1/2015 – 9/30/2037	**Firm Sales #1** 10/1/2011– 10/31/2019	**Firm Sales #2** 1/1/2013 – 5/31/2022	

Antero Transportation Portfolio



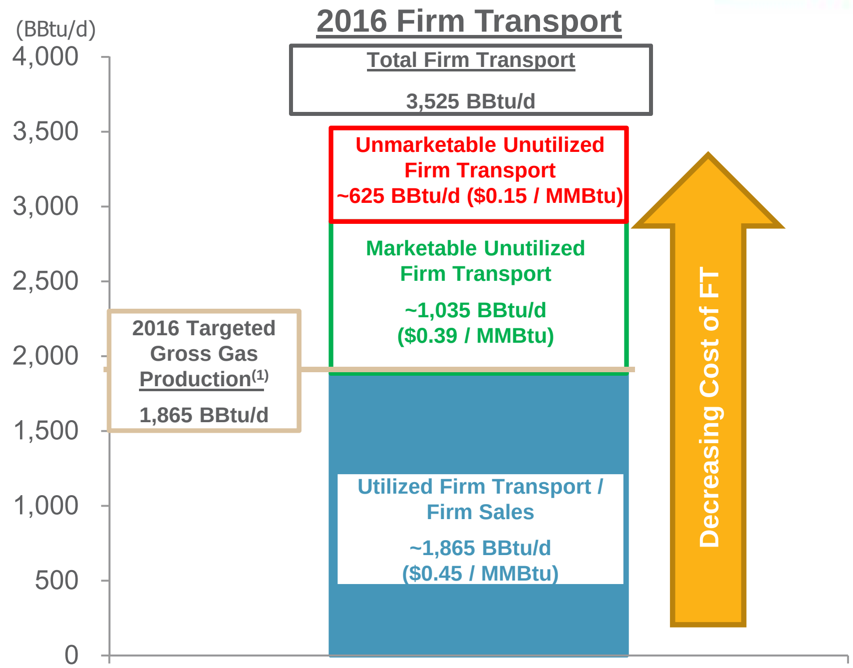
1. Assumes production growth guidance of 17% in 2016 and targeted 20% to 25% annual production growth in 2017.
2. Based on 2016 production guidance of 1.750 Bcfe/d.
3. Assumes 30% to 50% mitigation on excess capacity and current spreads based on strip pricing as of 12/31/2015.

PORTFOLIO APPROPRIATELY DESIGNED TO ACCOMMODATE GROWTH

- **Antero projects firm transportation in excess of equity gas production of approximately 1,660 BBtu/d in 2016**

FT Segment (Location)	Excess Capacity (BBtu/d)	Marketable / Unmarketable
Columbia / TGP (Marcellus)	560	Marketable
ANR North / ANR South (Utica)	475	Marketable
EQT / M3 (Marcellus)	625	Unmarketable
Total Excess Firm Transport	**1,660**	

- **Expect to market or mitigate a portion of the cost of approximately 1,035 BBtu/d of the excess FT with 3rd party gas**
- **Expect to fully utilize FT portfolio by 2019, based on five year development plan (excludes Appalachia based FT directed to unfavorable indices)**



	2016 FT Portfolio and Projected Gas Sales
Net Gas Production Target (MMcf/d) (1)	1,355
Net Revenue Interest Gross-up	*80%*
Gross Gas Production Target (MMcf/d)	1,695
BTU Upgrade (2)	x1.100
Gross Gas Production Target (BBtu/d)	**1,865**
Firm Transportation / Firm Sales (BBtu/d)	**3,525**
Estimated % Utilization of FT/FS	*53%*
Excess Firm Transportation	**1,660**
Marketable Firm Transport (BBtu/d) (3)	1,035
Unmarketable Firm Transportation	625
Estimated % Utilization of FT/FS Portfolio (Including Marketable FT)	**82%**

1. *Based on 2016 net daily gas production guidance.*
2. *Assumes 1100 BTU residue sales gas.*
3. *Represents excess firm transportation that is deemed marketable to 3rd parties based on a positive differential between the receipt and delivery points of the FT capacity, less variable transport cost.*

FT MARKETING EXPENSE UPDATE

2016 Projected Marketing Expenses:

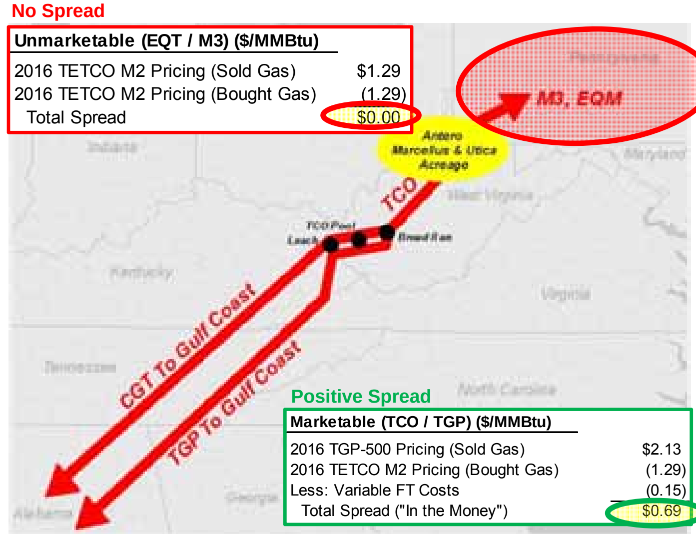
($ in millions, except per unit amounts)	Demand Fee ($ / MMBtu)	2016E Marketing Expenses	2016E Marketing Revenue	2016E Marketing Expenses, Net
"Unmarketable" Firm Transport				
625 BBtu/d of EQT / M3 Appalachia FT	$0.15	$35	-	$35
"Marketable" Firm Transport Capacity				
560 BBtu/d of Columbia / TGP	$0.49	$101	$42 - $71	$31 - $59
475 BBtu/d of ANR North / ANR South	$0.24	42	$6 - $11	$32 - $36
Sub-Total		$144	$48 - $82	$63 - $95
Grand Total - 2016 Marketing Expenses, Net		$179	$48 - $82	**~$95 to $125 MM**
$ / Mcfe - 2016 Targeted Production (1)		*$0.28*	*$0.08 - $0.13*	***$0.15 - $0.20***

2016 Marketing Revenue Projection:

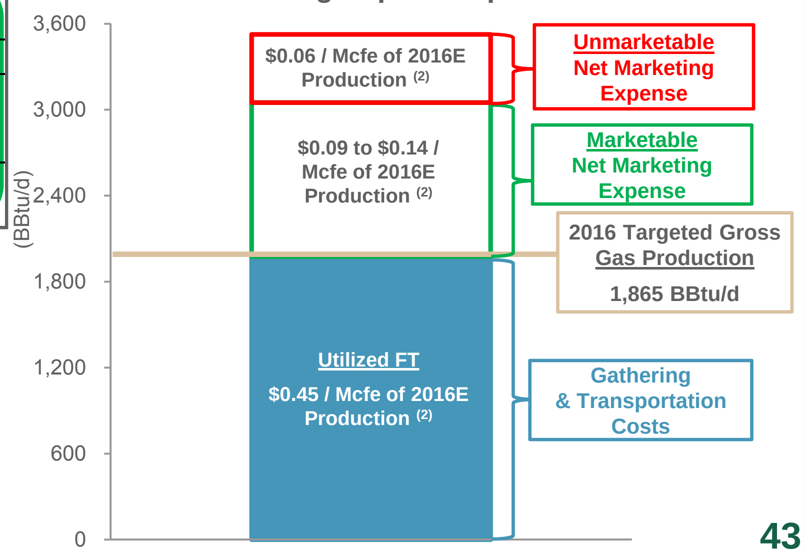
	2016E Marketing Spread ($ / MMBtu) (2)	2016E Marketing Revenue Assuming % Volume Mitigated: 30%	50%
"Marketable" Firm Transport Capacity			
560 BBtu/d of Columbia / TGP	$0.69	$42	$71
475 BBtu/d of ANR North / ANR South	$0.12	6	11
Sub-Total		$48	$82
$ / Mcfe - 2016E Targeted Production (1)		*$0.08*	*$0.13*

Based on the 2016 guidance of 17% annual production growth, Antero projects net marketing expenses of $0.15 to $0.20 per Mcfe in 2016

Illustrative Marketing Example:



2016 FT and Marketing Expenses per Unit:



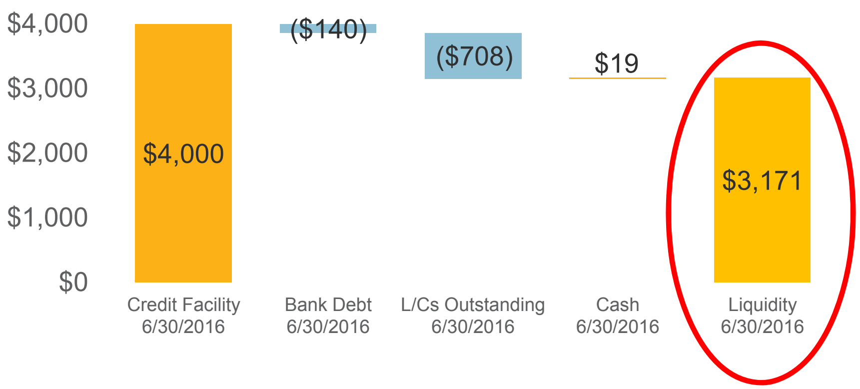
NOTE: Analysis based on strip pricing as of 03/31/2016.

1. *Represents 2016 net production growth guidance of 17% to 1,750 MMcfe/d.*
2. *Spread for each respective "marketable" firm transport represents the difference between the gas price Antero would receive at the delivery point of each pipeline versus the price Antero would pay to buy gas at the receipt point of each piece of capacity, less the variable costs to transport on each segment of firm transportation.*

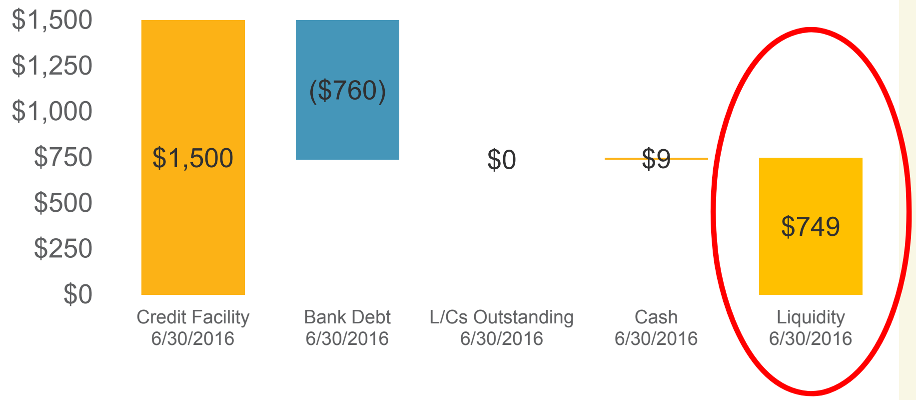
STRONG FINANCIAL LIQUIDITY AND DEBT TERM STRUCTURE

- Approximately $3.9 billion of combined AR and AM financial liquidity as of 6/30/2016
- No leverage covenant in AR bank facility, only interest coverage and working capital covenants

PRO FORMA AR LIQUIDITY POSITION ($MM)[1]

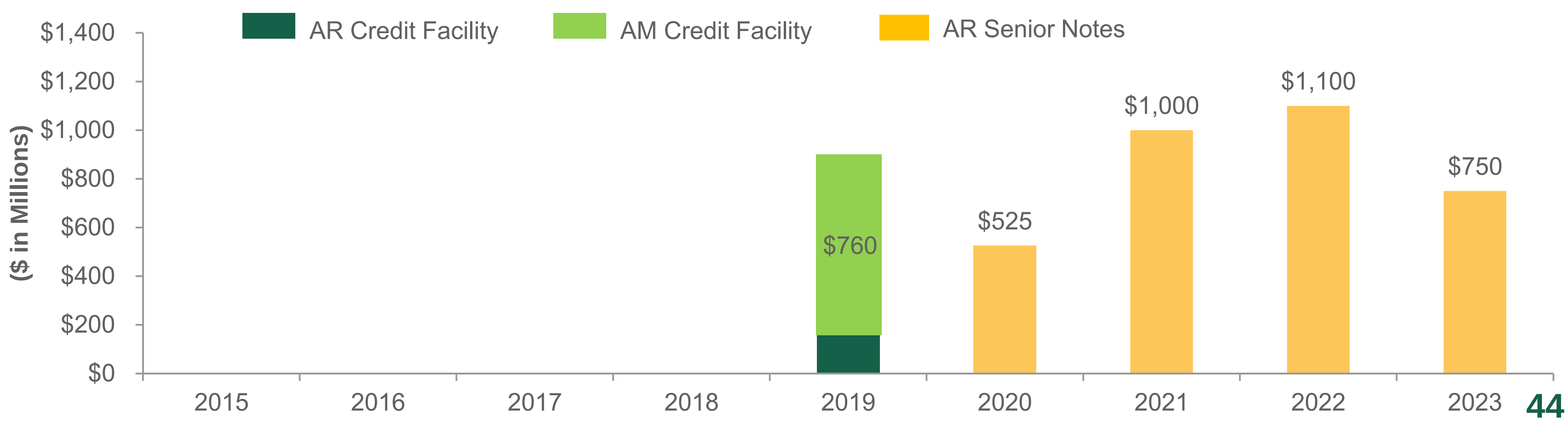


AM LIQUIDITY POSITION ($MM)



- Recent credit facility increases and equity offerings have allowed Antero to reduce its cost of debt to 4.1% and significantly enhance liquidity with an average debt maturity of November 2020

DEBT MATURITY PROFILE[1]



1. As of 6/30/2016.

POSITIVE RATINGS MOMENTUM

- Antero's corporate credit ratings were recently affirmed at Ba2/BB by Moody's and S&P, respectively, despite the severe commodity price down cycle

Moody's / S&P Historical Corporate Credit Ratings

Moody's Rating Rationale

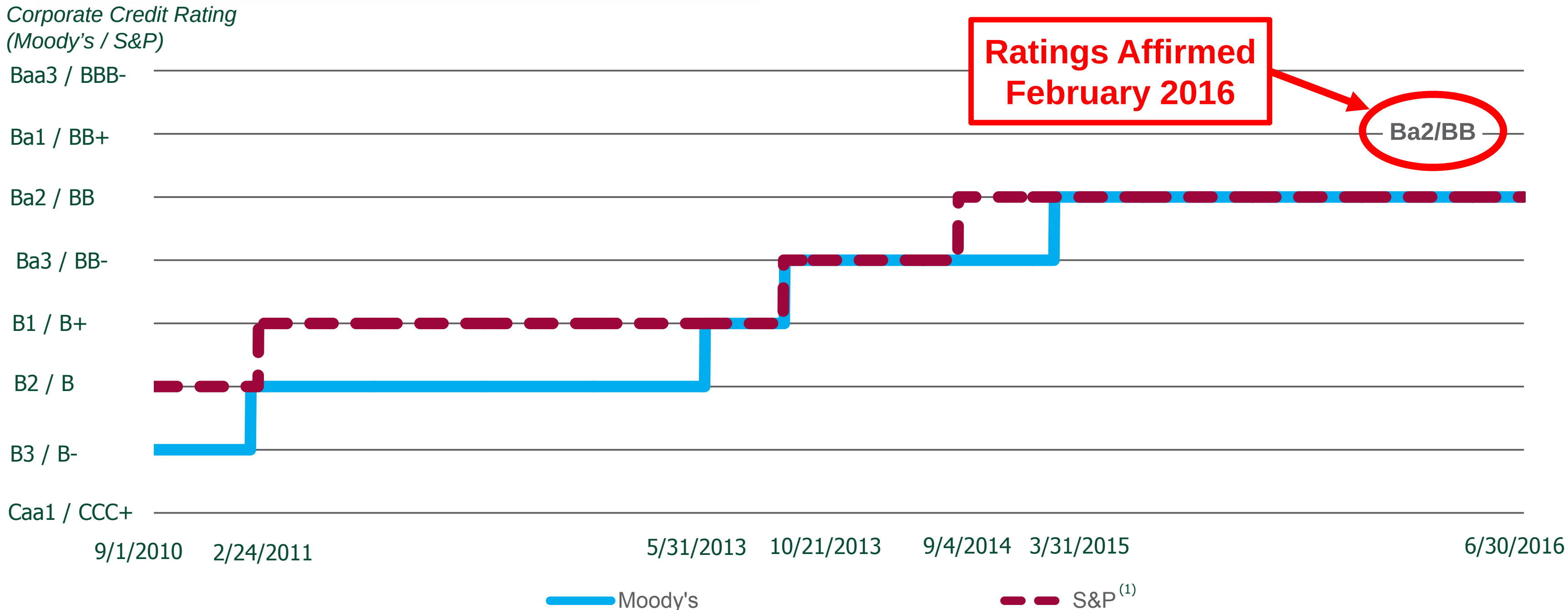
"Moody's confirmed Antero Resources' rating, which reflects its strong hedge book through 2018 and good liquidity. Antero has $3.1 billion in unrealized hedge gains, $3 billion of availability under its $4 billion committed revolving credit facility and a 67% interest in Antero Midstream Partners LP.

- Moody's Credit Research, February 2016

S&P Rating Rationale

"Outlook Stable. The affirmation reflects our view that Antero will maintain funds from operations (FFO)/Debt above 20% in 2016, as it continues to invest and grow production in the Marcellus Shale. The company has very good hedges in place, which will limit exposure to commodity prices."

- S&P Credit Research, February 2016



1. Represents corporate credit rating of Antero Resources Corporation / Antero Resources LLC.

ANTERO RESOURCES DECEMBER 31, 2015 RESERVES

- Antero's proved reserves were 13.2 Tcfe, while its 3P reserves were 37.1 Tcfe
- Proved pre-tax PV-10 at strip prices was $5.7 billion, while the 3P pre-tax PV-10 was $11.2 billion
  – Including hedges, the proved pre-tax PV-10 was $8.2 billion while the 3P pre-tax PV-10 was $13.7 billion

Reserves Detail – 12/31/2015

	Marcellus Shale				
	Gas (Bcf)	Liquids (MMBbl)	Total (Bcfe)	PV-10 ($MM) SEC(1)	Strip(2)
Proved	8,073	555	11,406	$2,749	$4,544
Probable	14,216	458	16,961		
Possible	1,025	43	1,282		
Total 3P	23,314	1,056	29,649	$2,885	$8,647
% Liquids(3)			21%		

	Ohio Utica Shale				
	Gas (Bcf)	Liquids (MMBbl)	Total (Bcfe)	PV-10 ($MM) SEC(1)	Strip(2)
Proved	1,459	58	1,809	$885	$1,140
Probable	3,972	83	4,468		
Possible	951	40	1,191		
Total 3P	6,381	181	7,468	$863	$2,535
% Liquids(3)			15%		

	Combined Reserves				
	Gas (Bcf)	Liquids (MMBbl)	Total (Bcfe)	PV-10 ($MM) SEC(1)	Strip(2)
Proved	9,532	614	13,215	$3,634	$5,684
Probable	18,188	540	21,429		
Possible	1,975	83	2,472		
Total 3P	29,695	1,237	37,117	$3,748	$11,182
% Liquids(3)			20%		

1. *2015 SEC prices were $2.56/MMBtu for natural gas and $50.13/Bbl for oil on a weighted average Appalachian index basis.*
2. *Pre-tax PV-10 based on annual strip pricing for first 10-years and flat thereafter as of December 31, 2015. NGL pricing assumes 39%, 46% and 48% of WTI strip prices for 2016, 2017 and 2018 and thereafter, respectively.*
3. *Represents liquids volumes as a percentage of total volumes. Combined liquids comprised of 1,145 million barrels of NGLs (including 182 million barrels of ethane) and 92 million barrels of oil.*

ANTERO RESOURCES EBITDAX RECONCILIATION

EBITDAX Reconciliation

($ in millions)	Quarter Ended 6/30/2016	LTM Ended 6/30/2016
EBITDAX:		
Net income including noncontrolling interest	$(575.5)	$155.5
Commodity derivative fair value (gains)	684.6	(1,219.5)
Net cash receipts on settled derivatives instruments	292.5	1,092.7
Interest expense	62.6	247.2
Income tax expense (benefit)	(376.5)	41.0
Depreciation, depletion, amortization and accretion	198.0	741.4
Impairment of unproved properties	19.9	104.9
Exploration expense	1.1	4.0
Equity-based compensation expense	25.8	91.8
Equity in earnings of unconsolidated affiliate	(0.5)	(0.5)
Contract termination and rig stacking	0.0	27.6
Consolidated Adjusted EBITDAX	**$332.1**	**$1,286.1**

ANTERO MIDSTREAM EBITDA RECONCILIATION

EBITDA and DCF Reconciliation

$ in thousands	Six months ended June 30, 2015	Six months ended June 30, 2016
Reconciliation of Net Income to Adjusted EBITDA and Distributable Cash Flow:		
Net income	$67,451	$92,829
Interest expense	3,222	7,582
Depreciation expense	41,955	47,963
Accretion of contingent acquisition consideration	-	6,857
Equity-based compensation	12,376	12,766
Equity in earnings from unconsolidated affiliate	-	(484)
Adjusted EBITDA	$125,004	$167,513
Pre-Water Acquisition net income attributed to parent	(32,353)	-
Pre-Water Acquisition depreciation expense attributed to parent	(12,282)	-
Pre-Water Acquisition equity-based compensation expense attributed to parent	(2,365)	-
Pre-Water Acquisition interest expense attributed to parent	(1,556)	-
Adjusted EBITDA attributable to the Partnership	76,448	167,513
Cash interest paid - attributable to Partnership	(1,177)	(7,708)
Cash reserved for payment of income tax witholding upon vesting of Antero Midstream LP equity-based compensation awards	-	(2,000)
Cash to be received from unconsolidated affiliate	-	778
Maintenance capital expenditures attributable to Partnership	(5,787)	(11,518)
Distributable Cash Flow	$69,484	$147,065

CAUTIONARY NOTE

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, 2015 included in this presentation have been audited by Antero's third-party engineers. Unless otherwise noted, reserve estimates as of December 31, 2015 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, 2015. 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.