Third Quarter 2017
Earnings Call Presentation

November 2, 2017

Antero
Resources

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, 2016 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, 2016 and in the Company’s subsequent filings with the SEC.

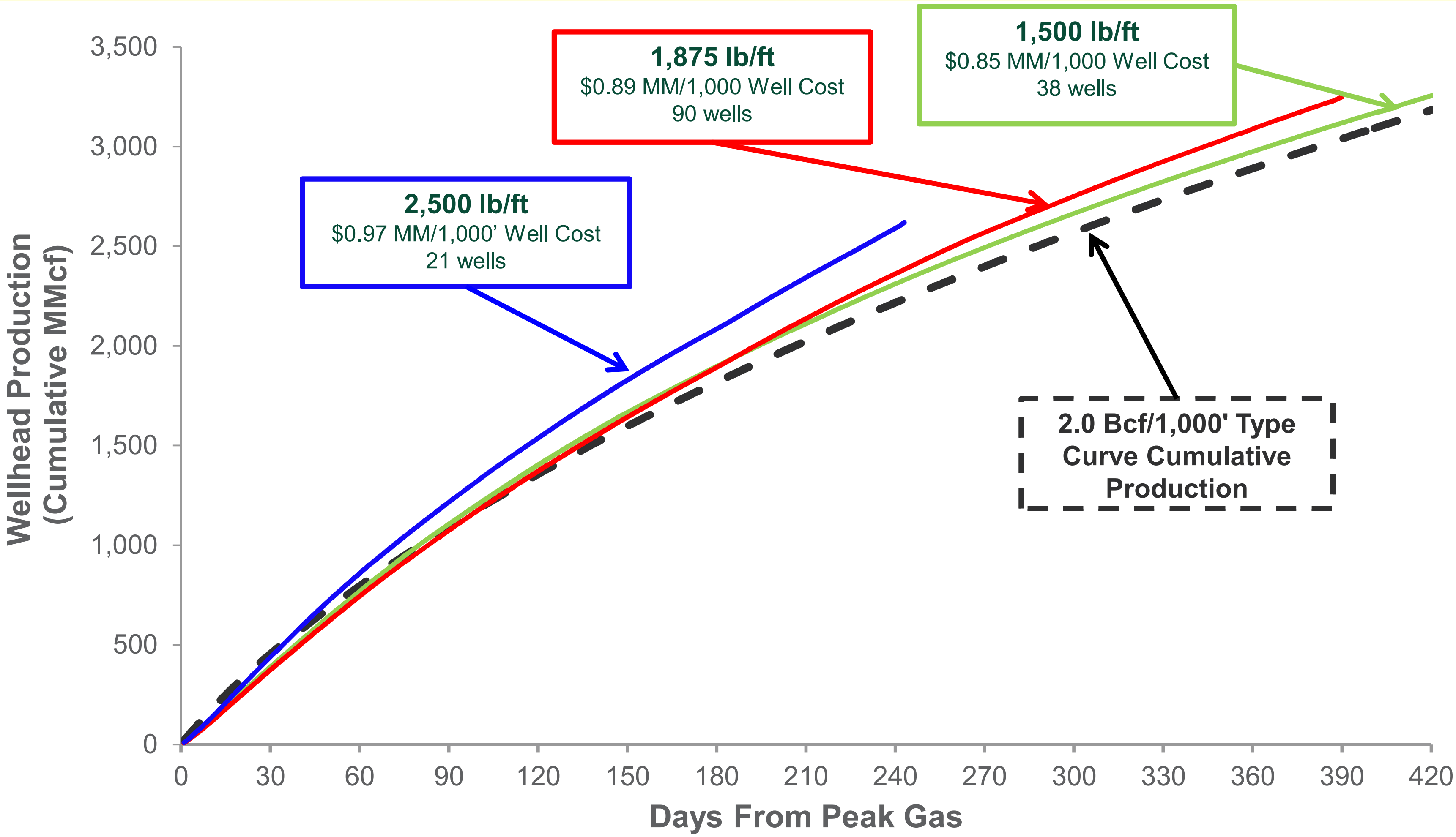
Any forward-looking statement speaks only as of the date on which such statement is made and the Company undertakes no obligation to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by applicable law.

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.

Higher Intensity Completions Are Increasing EURs

AR's production from advanced completions is outperforming the 2.0 Bcf/1,000' wellhead type curve – 2,500 lb/ft completions are 17% above type curve (First 243 days)

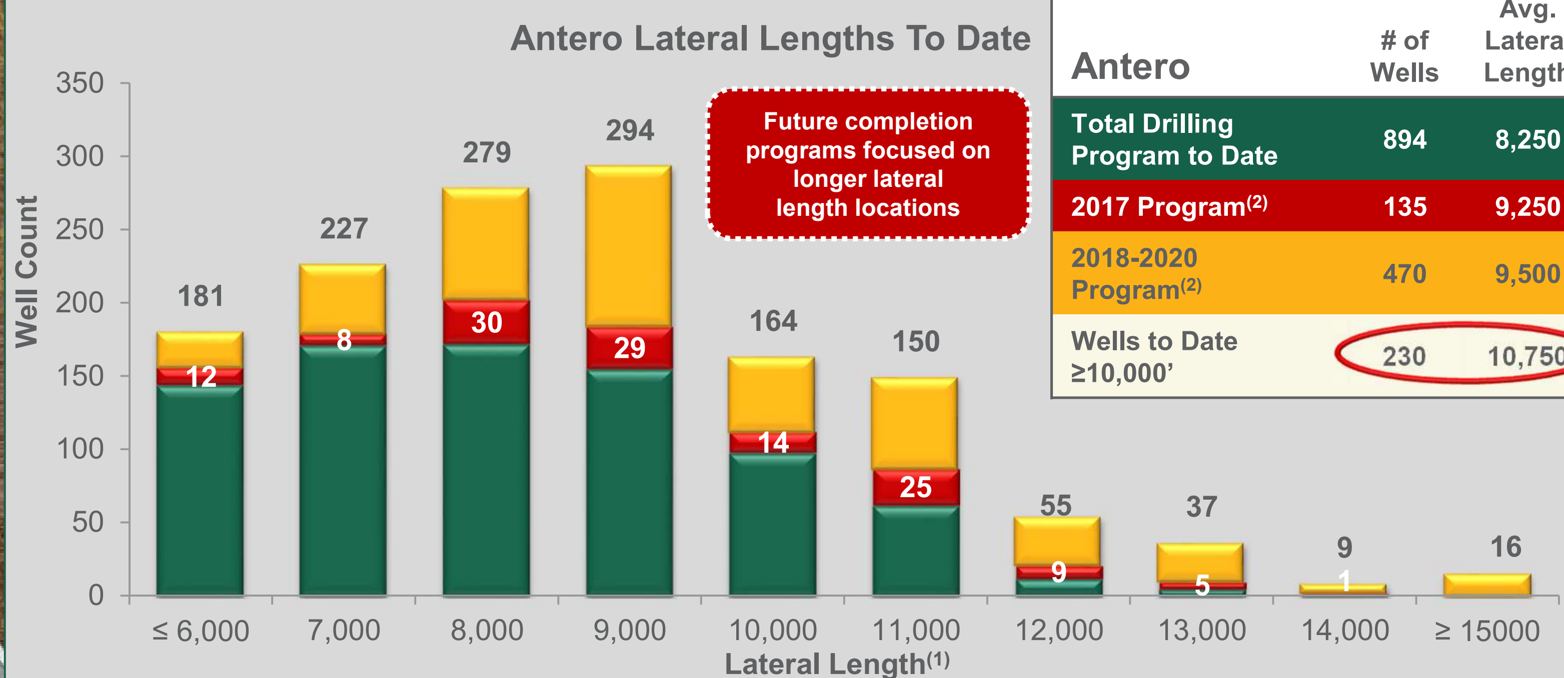
AR Type Curve Outperformance(1)(2)



1. *Cumulative average production per well normalized to a 9,000' lateral. Cumulative production lines excludes wellhead condensate.*
2. *1,875 pounds per foot type curve represents 1,750 pounds per foot wells and 2,000 pounds per foot wells.*

Longer Laterals Materially Improve Economics

Antero has been a leader in drilling long laterals in Appalachia



Antero	# of Wells	Avg. Lateral Length
Total Drilling Program to Date	894	8,250
2017 Program[2]	135	9,250
2018-2020 Program[2]	470	9,500
Wells to Date ≥10,000’	230	10,750

6,000 Foot Lateral

Pre-Tax Economics	
ROR (%)	39%
PV-10 ($MM)	$5.1

9,000 Foot Lateral

Pre-Tax Economics	
ROR (%)	55%
PV-10 ($MM)	$9.5

12,000 Foot Lateral

Pre-Tax Economics	
ROR (%)	61%
PV-10 ($MM)	$12.5

15,000 Foot Lateral

Pre-Tax Economics	
ROR (%)	68%
PV-10 ($MM)	$16.3

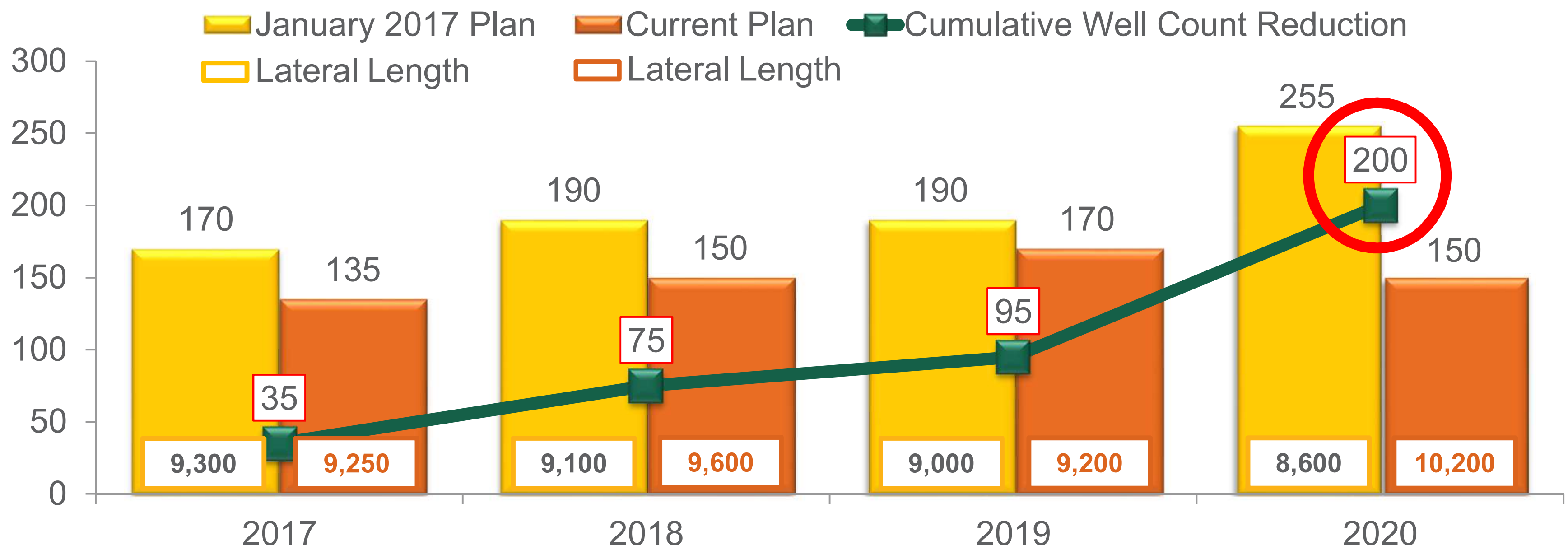
NOTE: Assumes 2.0 Bcf/1,000’ type curve for the Antero Marcellus Highly-Rich Gas (1250 Btu) and Nymex Henry Hub prices of $3.00 and WTI of $54.

1. *All laterals rounded to the nearest thousand. 788 of the 894 wells have been completed*
2. *Represents wells placed to sales.*

Improving Capital Efficiencies

Improving EURs, longer laterals and reduced cycle times results in 200 fewer well completions saving approximately $1.5 billion through 2020 while still delivering essentially the same production targets

Planned Antero Well Completions by Year (2017-2020)



Drilling and Completion Capital Budget and Targets [1]

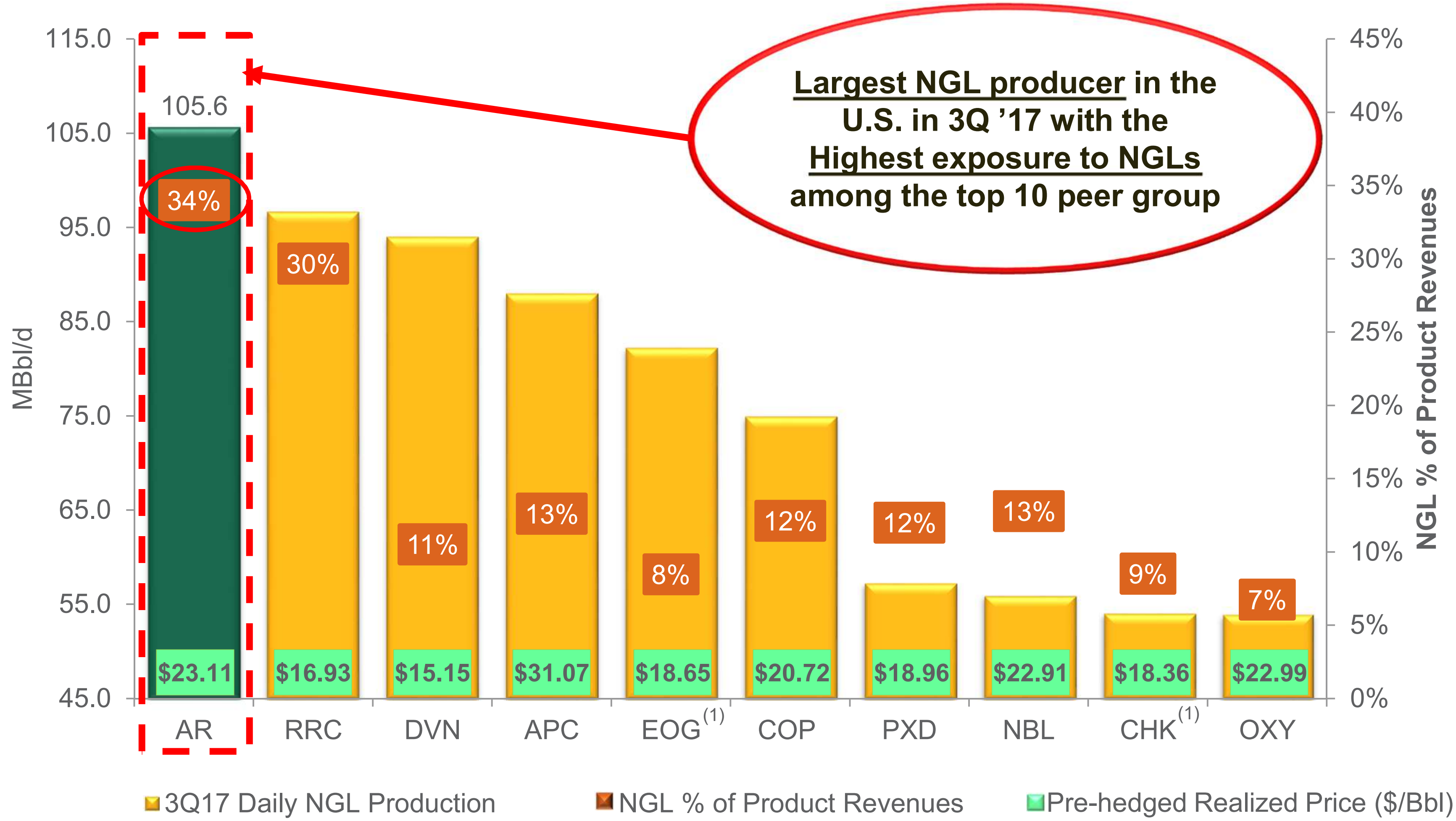
	2017 Budget	2018 Target	2019 Target	2020 Target
Drilling & Completion ($MM)	$1,300	~$1,300	$1,500	$1,500
% Production Growth Target	20% CAGR Through 2020 (4-Year CAGR)			

1. *Represents a combination of 2,000 lb/ft and 2,500 lb/ft completions.*

Largest NGL Producer in the U.S.

Antero is the largest NGL producer in the U.S and has the most NGL exposure at 34% of total upstream company revenues

Top U.S. NGL Producers (MBbl/d) – 3Q 2017

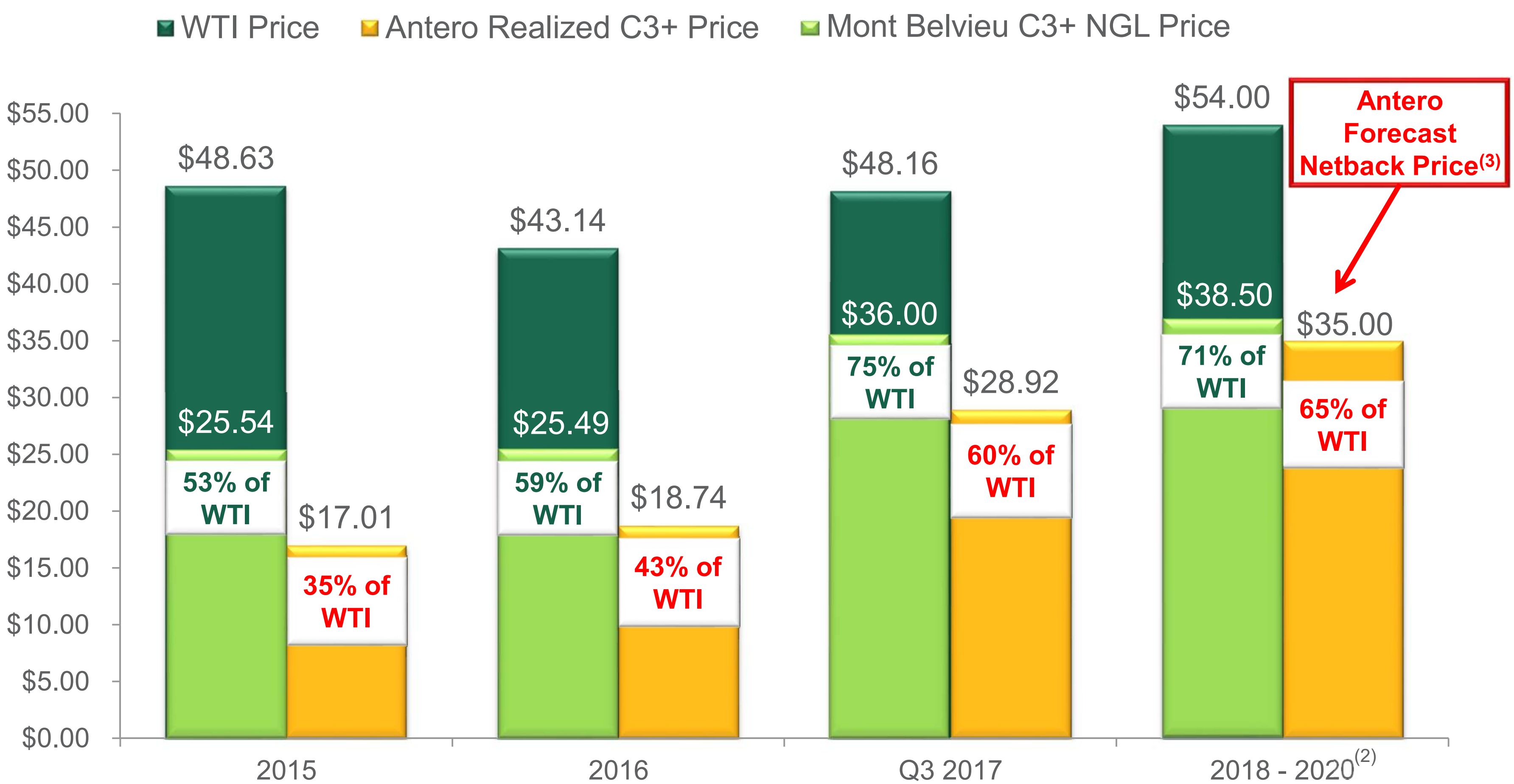


Source: SEC filings and company press releases. Realized prices are weighted average including ethane (C2) where applicable.
1. CHK and EOG C2+ production, realized prices and NGL percentage of product revenues based on 2Q 2017 actual results.

Significant Increase in C3+ Netbacks

Despite a flat oil price environment, Antero's pre-hedged realized C3+ NGL price has increased 70% since 2015 and is expected to improve further

Antero C3+ NGL Realized Pricing ($/Bbl)(1)

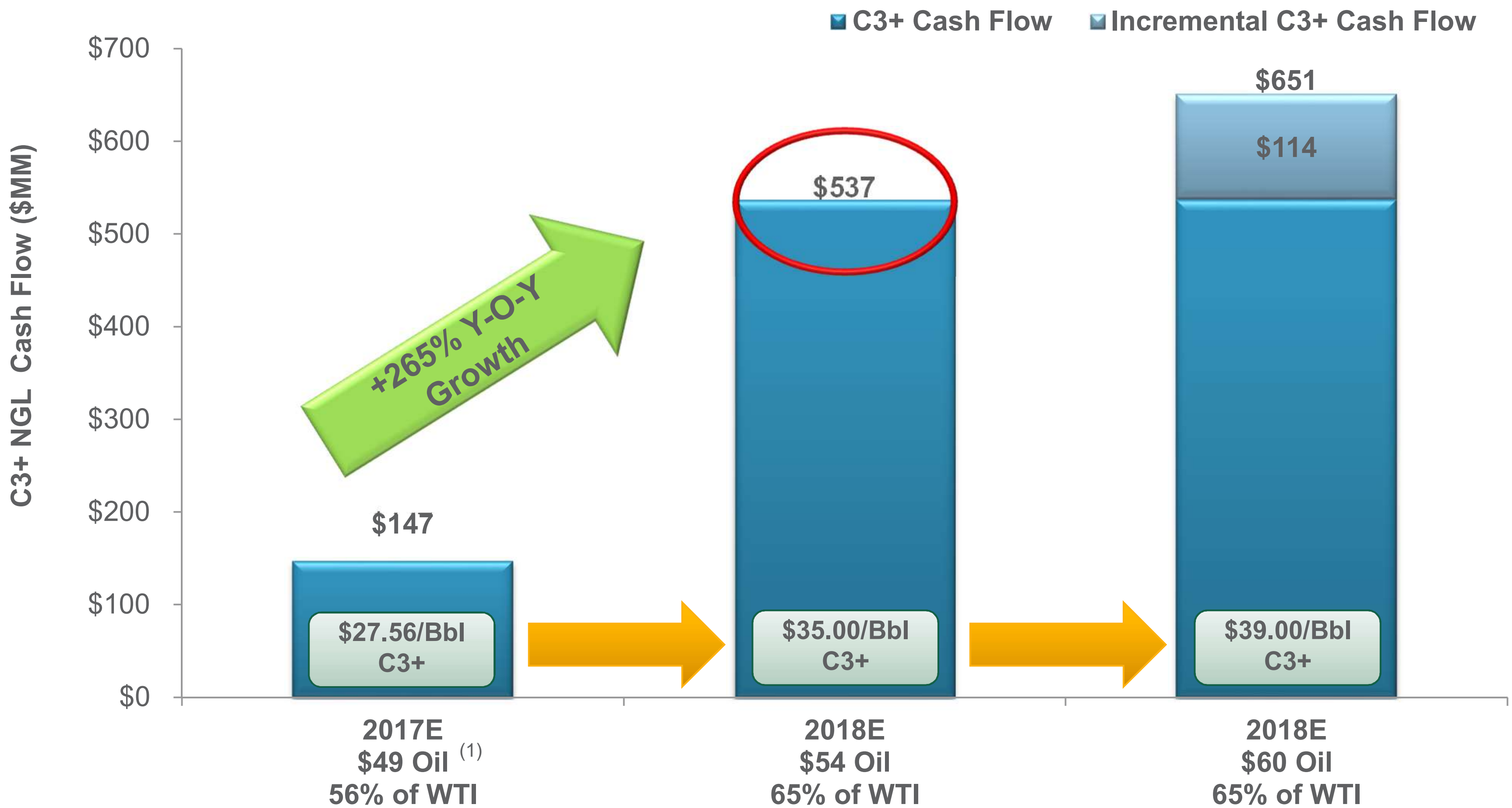


1. WTI price and Mont Belvieu C3+ NGL price forecasts and represent strip pricing as of 9/25/2017. Antero year to date 2017 realized C3+ NGL pricing represents actuals through 6/30/2017. 2018-2020 realized C3+ NGL pricing reflects current company targets.
2. Based on unhedged contracted differentials for C4+ NGL products, guidance from midstream providers and strip pricing as of 10/27/2017.
3. Net of ME2 fees. Antero will account for ME2 fees as an expense once ME2 is placed in-service.

Powerful C3+ NGL Pricing Upside Exposure

Antero expects significant cash flow growth in 2018 from the improvement in NGL pricing with attractive upside to further increases in liquids pricing

Significant Improvement in Cash Flow from C3+ NGLs (2018 vs. 2017)



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.

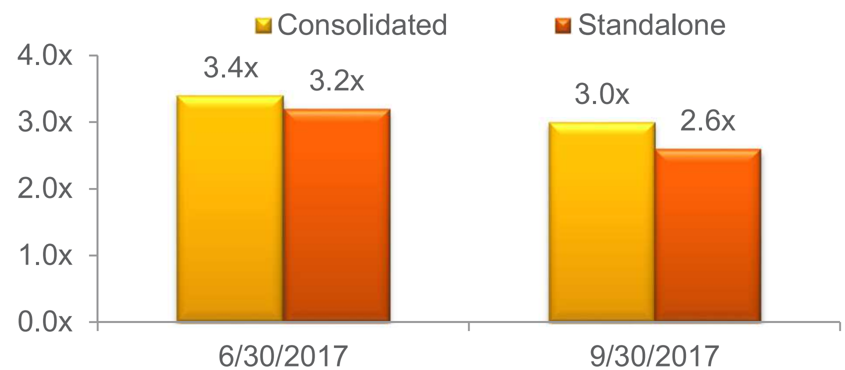
(1) Represents annualized actual results for nine months ended September 30, 2017, annualized.

$1 Billion Delevering Program Completed

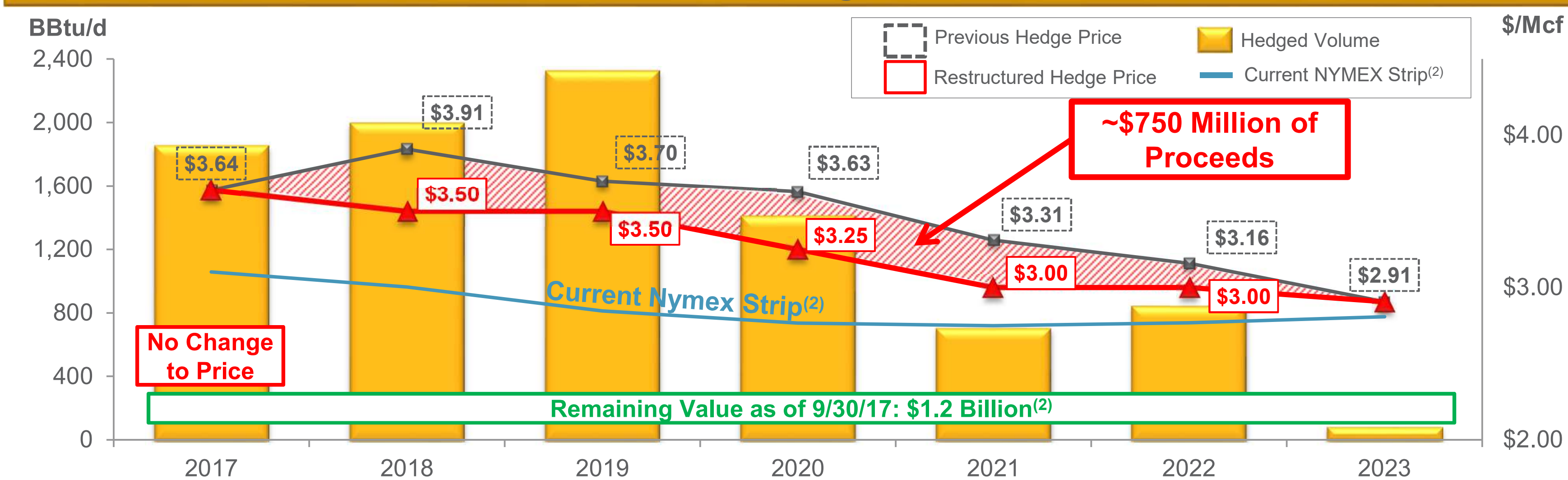
Antero monetized over $1 billion of non-E&P assets through the sale of $311 million of AM common units and $750 million through hedge restructuring
- Reduced stand-alone net debt/LTM EBITDAX to 2.6x

- Restructuring of hedge swap prices resulted in no change to hedge volumes
- 80% of targeted natural gas production hedged through 2020 at $3.43/MMBtu
  - *$1.2 billion of remaining hedge value*
- Utilizing a portion of net operating losses carried forward to eliminate cash taxes on realized gains

AR Leverage Reduction[1]



Natural Gas Hedge Position

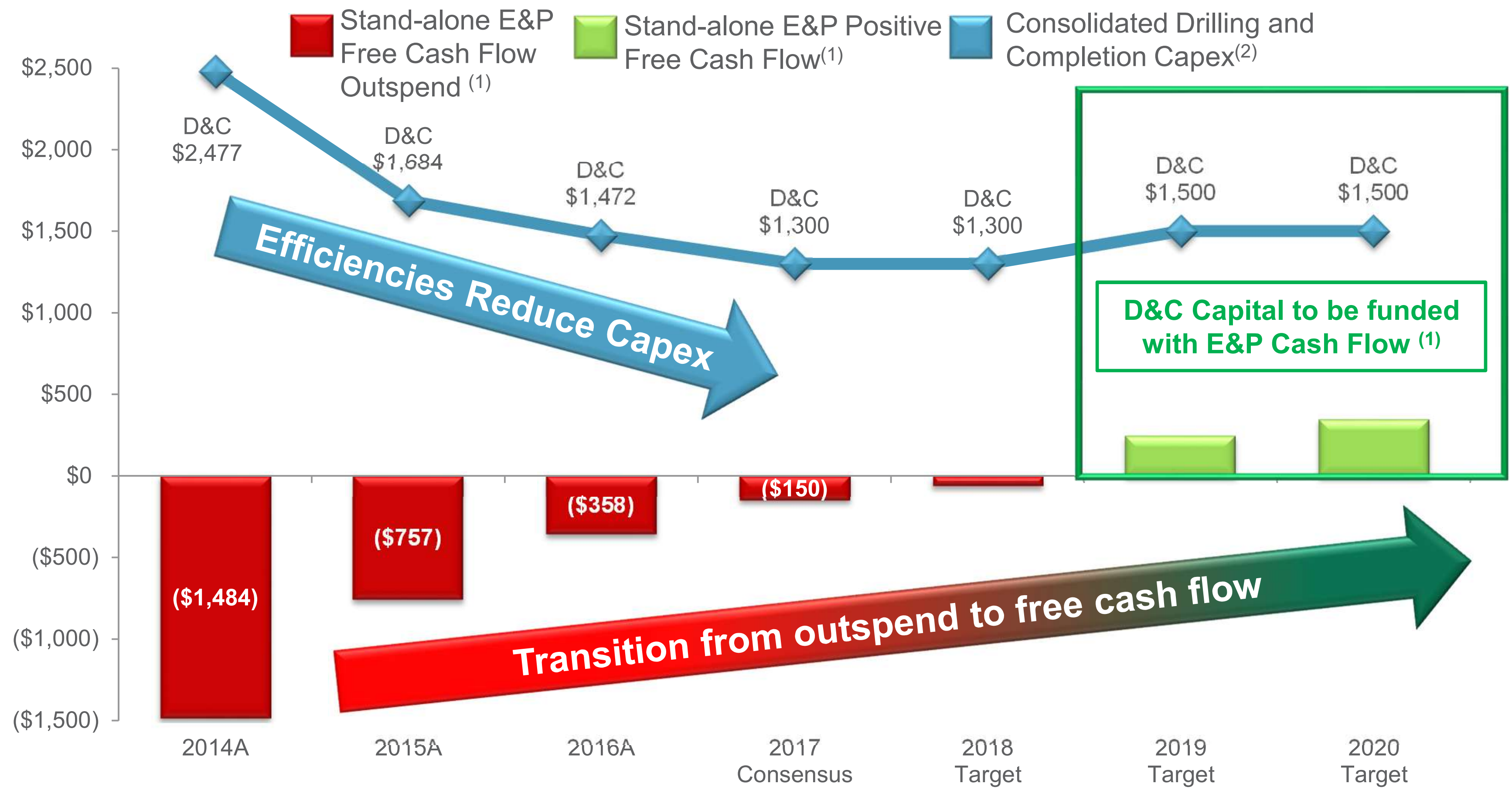


1. *AR stand-alone LTM EBITDAX includes $127 million in distributions from AR's ownership of AM common units.*
2. *Nymex strip pricing as of 9/30/2017.*

Capital Efficiency Drives Elimination of Outspend

Capital efficiencies have significantly reduced E&P outspend and are expected to result in drilling and completion (D&C) capex within E&P free cash flow by 2019

D&C Capex vs. Stand-alone E&P Cash Flow ($MM) - $3.00 Gas / $54 Oil



Note: E&P cash flow represents E&P cash flow from operations plus AM distributions from condensed consolidating statement of cash flows in Antero Resources' 10-K.

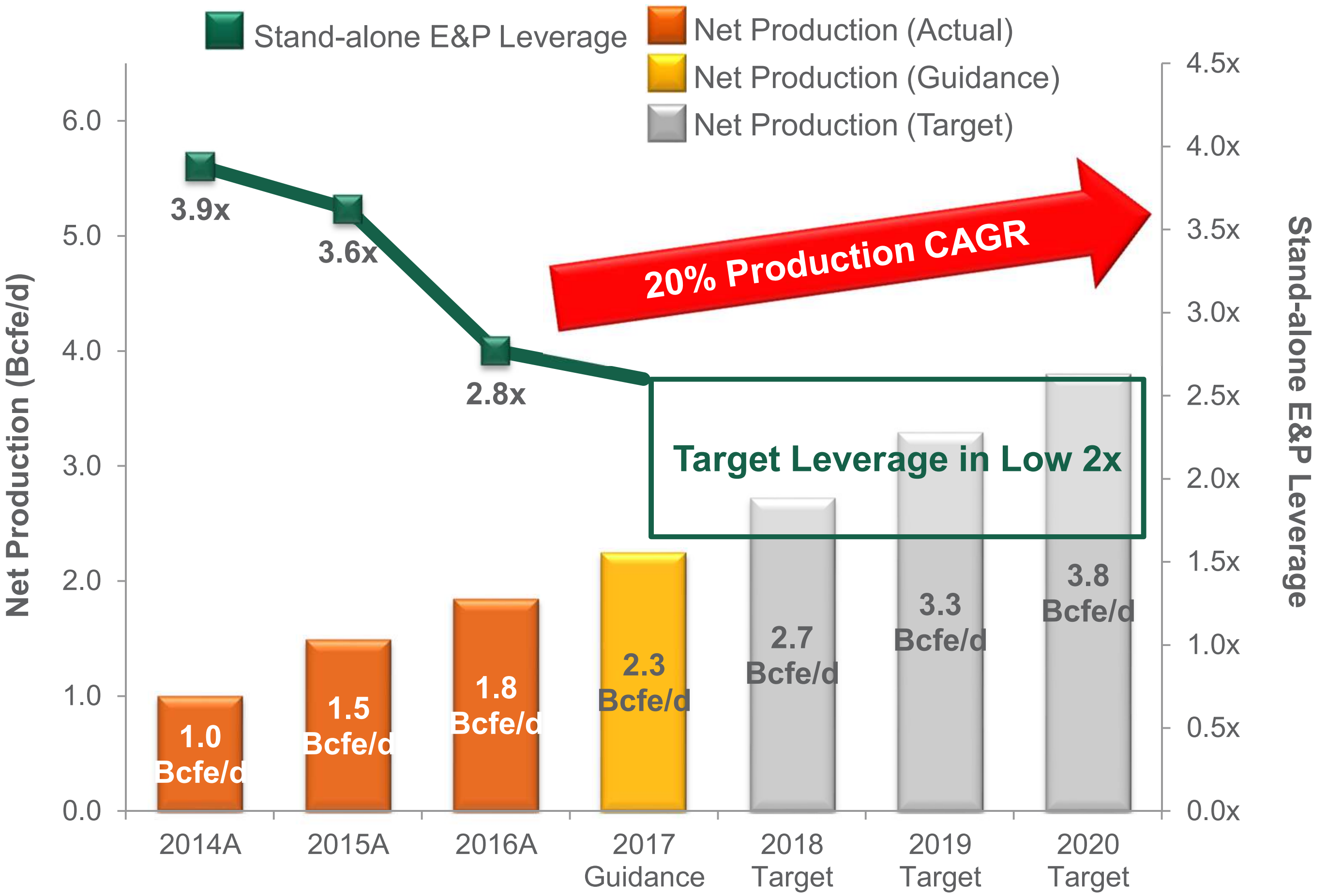
(1) E&P free cash flow represents AR stand alone cash flow from operations, plus distributions from LP ownership in AM, plus earn out payments associated with water drop-down ($125 MM in each of 2019 and 2020) less stand-alone D&C capex which includes water fees paid to AM for completions which are capitalized on stand-alone basis.

(2) Consolidated D&C capex excludes water fees paid to AM for completions.

Attractive Long Term Outlook

Antero is now well positioned to generate free cash flow and peer leading growth

Antero Resources Stand-alone E&P Long-Term Targets[1]



Reduce Capex & Leverage

Generate Free Cash Flow

Analyze Return of Capital to Shareholders

(1) *Assumes WTI price of $54 and Nymex Henry Hub price of $3.00.*

APPENDIX

Antero Resources – Q4'17 and 2017 Guidance

Key Operating & Financial Assumptions

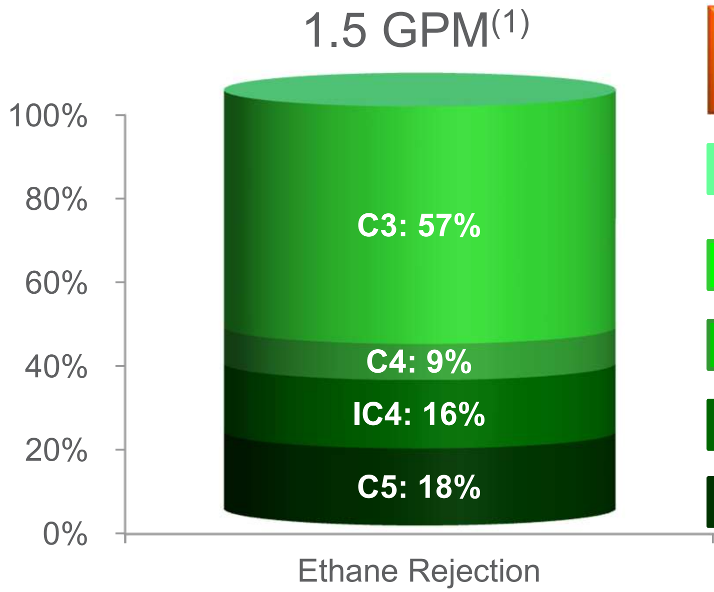
Key Variable	Updated 2017 Guidance[1]	Previous 2017 Guidance[1]	Q4 2017 Guidance
Net Daily Production (MMcfe/d)		2,250 – 2,300	
Net Residue Natural Gas Production (MMcf/d)		1,650 – 1,675	
Net C3+ NGL Production (Bbl/d)		68,000 – 71,000	
Net Ethane Production (Bbl/d)		26,000 – 27,000	
Net Oil Production (Bbl/d)		6,000 – 7,000	
Net Liquids Production (Bbl/d)		100,000 – 105,000	
Natural Gas Realized Price Differential to NYMEX Before Hedging ($/Mcf)[2][3]	($0.15) – ($0.10)	+$0.00 – $0.10	($0.20) – ($0.15)
Oil Realized Price Differential to NYMEX WTI Oil Before Hedging ($/Bbl)	($7.00) – ($6.50)	($9.00) – ($7.00)	($6.00) – ($5.00)
C3+ NGL Realized Price (% of NYMEX WTI)[2]	57.5% – 62.5%	50% – 55%	70% – 75%
Ethane Realized Price (Differential to Mont Belvieu) ($/Gal)	$0.00	$0.00	$0.00
Consolidated EBITDAX ($MM):			$410 - $440
Operating:			
Cash Production Expense ($/Mcfe)[4]	$1.55 – $1.65		
Marketing Expense, Net of Marketing Revenue ($/Mcfe)	$0.075 – $0.125		
G&A Expense ($/Mcfe)	$0.15 – $0.20		
Capital Expenditures ($MM):			
Drilling & Completion	$1,300		
Land	$200		
Total Capital Expenditures ($MM)	$1,500		

1. *Updated guidance per press release dated 11/02/2017.*
2. *Based on strip pricing as of 10/27/2017.*
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 NGL Barrel (September Pricing)

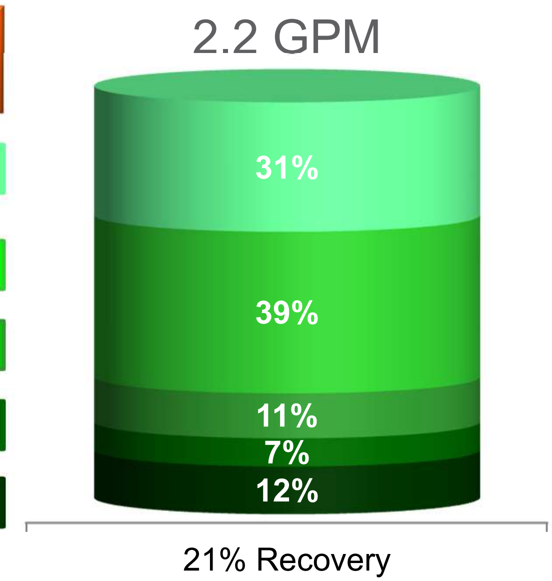
- Antero realized $33.23/Bbl for its C3+ NGL barrels in September 2017
  - 67% of WTI oil price
- Including 21% ethane recovery, Antero realized $26.54 per barrel for its NGL barrels
  - Antero is currently leaving approximately 124,000 Bbl/d of ethane in the gas stream

NGL Barrel Composition & Pricing – Ethane Rejection vs. Partial Recovery



Mont Belvieu September 2017 Pricing

Ethane (C2):	$0.27/Gallon
Propane (C3):	$0.89/Gallon
Butane (C4):	$0.99/Gallon
IsoButane (IC4):	$1.02 /Gallon
Pentane (C5):	$1.17/Gallon



$40.75/Bbl	Mont Belvieu Pricing	$31.63/Bbl
$(7.52)/Bbl	Northeast Differential	$(5.09)/Bbl
$33.23/Bbl	Antero Realized Price ($/Bbl)	$26.54/Bbl
67%	% of WTI	53%

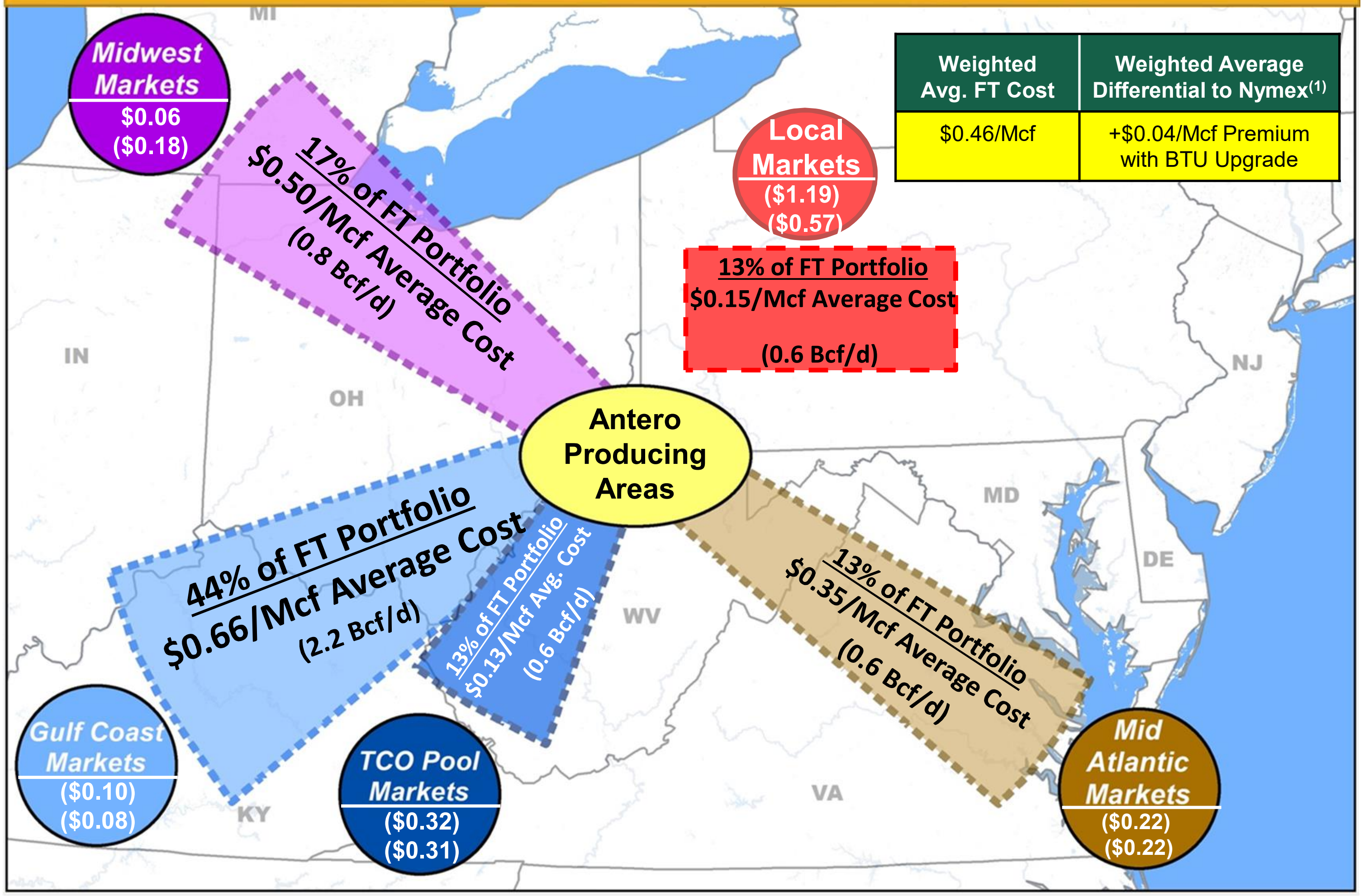
1. GPM represents gallons of NGLs per wellhead unprocessed Mcf.

Most Attractive Firm Transport Portfolio in Appalachia

Antero's natural gas takeaway position results in price certainty at attractive all-in netbacks to Nymex: Nymex less $0.42/Mcf expected 2017-2020, after deducting FT costs

Antero Firm Transportation Portfolio (2017-2019)

Weighted Avg. FT Cost	Weighted Average Differential to Nymex[1]
$0.46/Mcf	+$0.04/Mcf Premium with BTU Upgrade

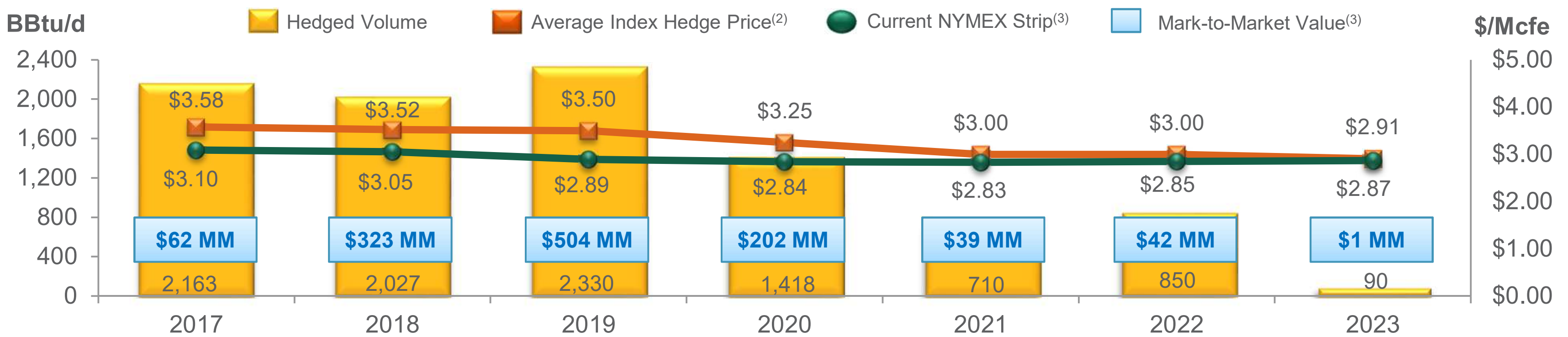


Note: Strip basis differentials to Nymex Henry Hub represents October 2017 and 2017-2019 strip pricing, respectively as of October 27th, 2017 for each index.
1. Weighted average differential to Nymex calculated using 2017-2019 strip pricing as of October 27th, 2017.

Largest E&P Gas Hedge Position in U.S.

Pro forma ~$1.2 billion mark-to-market unrealized gain based on 9/30/2017 prices with 2.9 Tcfe hedged from October 1, 2017 through year-end 2023 at $3.36 per MMBtu

Pro Forma Commodity Hedge Position[1]

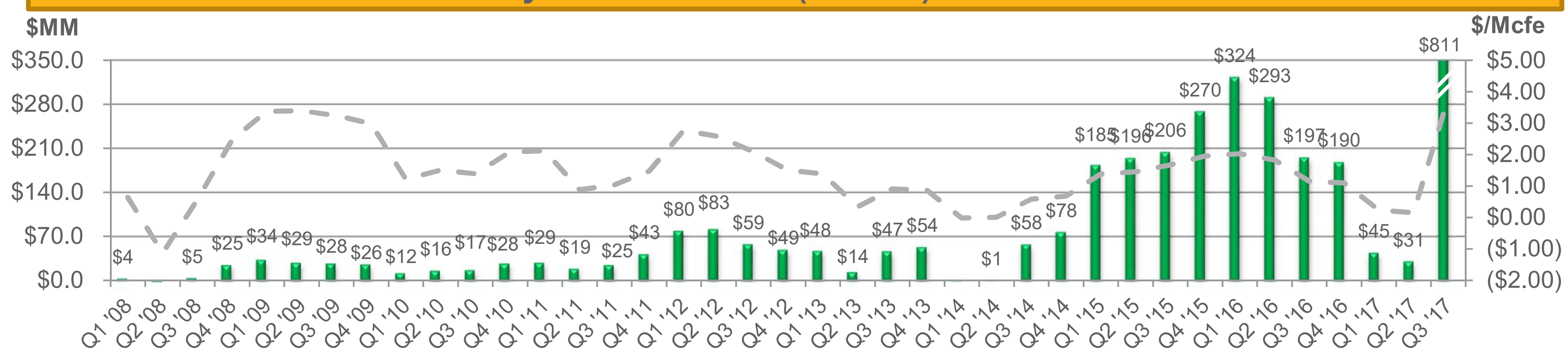


~ 95% of 2017 Guidance Hedged

~ 84% of 2018 Target Hedged

- **Hedging is a key component of Antero's business model due to the large, repeatable drilling inventory**
- **Antero has realized $3.6 billion of gains on commodity hedges since 2008 with gains realized in 37 of last 39 quarters[3]**

Quarterly Realized Gains/(Losses) – 1Q '08 - 3Q '17



1. *Pro forma for hedge monetization per press release dated 9/21/2017.*
2. *Weighted average index price based on volumes hedged assuming 6:1 gas to liquids ratio; excludes impact of TCO basis hedges. 27,500 Bbl/d of propane hedged in 2017 and 2,000 Bbl/d hedged in 2018. 20,000 Bbl/d of ethane hedged in 2017 and 3,000 Bbl/d of oil hedged in 2017.*
3. *As of 9/30/2017. Includes impact from $750 million hedge monetization in September 2017.*

3Q 2017 Segment EBITDAX and Capital Expenditures

1 Gathering and compression fees paid to Antero Midstream are included in Gathering, Processing & Transportation expense on stand-alone basis (eliminated on consolidated basis); Gathering and compression operating expenses borne by AM on stand-alone basis (included in GPT on consolidated basis)

2 Water fees paid to Antero Midstream included in Drilling & Completion capital expenditures on stand-alone basis; water operating expenses borne by AM on stand-alone basis and AR on consolidated basis

3Q 2017 Segment EBITDAX and Capital Expenditures

Stand-alone EBITDAX
Antero Resources : $284 Million[1]
Antero Midstream : $128 Million

($MMs)	Exploration & Production	Gathering & Processing	Water Handling & Treatment	Marketing	Elimination of Intersegment Transactions	Consolidated Total
Revenues:						
Third-Party	$660	$7	$0	$51	-	$718
Intersegment	1	98	93	-	(191)	-
Gains on settled derivatives	61	-	-	-	-	61
Total Revenue	**$722**	**$105**	**$93**	**$51**	**(191)**	**$780**
Cash operating expenses:						
Lease operating	$24	-	$52	-	($52)	$23
Gathering, Processing & Transp. (3rd party)	272	-	-	-	-	272
Gathering, Processing & Transp. (AM fees)	98	10	-	-	(98)	10
Production Taxes	22	0	1	-	-	23
G&A (before equity-based comp)	29	4	3	-	(0)	36
Marketing	-	-	-	79	-	79
Total Cash Operating Expenses	**$445**	**$15**	**$55**	**$79**	**($150)**	**$443**
Segment Adjust EBITDAX	**$278**	**$90**	**$38**	**($28)**	**($41)**	**$336**
	Antero Resources	Antero Midstream	Antero Midstream	Antero Resources		
Capital Expenditures:						
D&C (excluding water)	$265					$265
D&C (including water)	93	-	-	-	(41)	52
Land / Acquisitions	57	-	-	-	-	57
G&C / Water Infrastructure	-	99	48			147
Total CapEx	**$415**	**$99**	**$48**	**$0**	**($41)**	**$522**

On consolidated basis, water fees are eliminated from D&C capital, but water operating expenses are capitalized

1. *AR stand-alone EBITDAX represents E&P EBITDAX plus $35 million in distributions from AM ownership less net marketing expense.*

Antero Resources Stand-alone EBITDAX Reconciliation

AR Stand-alone EBITDAX Reconciliation

($ in millions)	**Three Months Ended** **09/30/2017**	**LTM Ended** **09/30/2017**
EBITDAX:		
Operating loss	$(114.1)	$(235.8)
Commodity derivative fair value losses	66.0	181.3
Net cash receipts on settled derivatives instruments	61.5	326.9
Depreciation, depletion, amortization and accretion	176.9	720.1
Impairment of unproved properties and accretion	41.0	198.8
Exploration expense	1.6	9.1
Change in fair value of contingent acquisitions consideration	(2.6)	(15.8)
Equity-based compensation expense	19.2	78.6
Gain on sale of assets	-	(93.8)
AM distributions net to AR ownership	34.8	126.8
Segment Adjusted EBITDAX	**$284.3**	**$1,296.2**

Antero Resources EBITDAX Reconciliation

EBITDAX Reconciliation

($ in millions)	Quarter Ended 9/30/2017	LTM Ended 9/30/2017
EBITDAX:		
Net income including noncontrolling interest	$(90.0)	$(197.3)
Commodity derivative fair value gains	66.0	181.3
Net cash receipts on settled derivatives instruments	61.5	326.9
Gain of sale on assets	-	(97.6)
Interest expense	70.1	273.2
Loss on early extinguishment of debt	-	16.9
Income tax expense	(45.1)	(160.5)
Depreciation, depletion, amortization and accretion	207.6	835.3
Impairment of unproved properties	41.0	198.8
Exploration expense	1.6	9.1
Equity-based compensation expense	26.4	105.7
Equity in earnings of unconsolidated affiliate	(7.0)	(11.3)
Distributions from unconsolidated affiliates	4.3	17.8
Consolidated Adjusted EBITDAX	**$336.4**	**$1,498.3**