Investor Presentation

2022 Guidance and Company Outlook

February 9, 2022

Cautionary Statements

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The Securities and Exchange Commission (SEC) permits oil and gas companies, in their filings with the SEC, to disclose only proved, probable and possible reserves that a company anticipates as of a given date to be economically and legally producible and deliverable by application of development projects to known accumulations. This presentation contains certain terms and estimates that are prohibited from being included in filings with the SEC pursuant to the SEC's rules. The SEC views such terms and estimates as inherently unreliable and these estimates may be misleading to investors unless the investor is an expert in the natural gas industry. Additionally, the SEC strictly prohibits us from aggregating proved, probable and possible (3P) reserves in filings with the SEC due to the different levels of certainty associated with each reserve category.

This presentation contains certain forward-looking statements within the meaning of Section 21E of the Securities Exchange Act of 1934, as amended, and Section 27A of the Securities Act of 1933, as amended. Statements that do not relate strictly to historical or current facts are forward-looking. Without limiting the generality of the foregoing, forward-looking statements contained in this news release include the expectations of plans, strategies, objectives and growth and anticipated financial and operational performance of EQT Corporation and its subsidiaries (collectively, the Company), including guidance regarding the Company's strategy to develop its reserves; drilling plans and programs (including the number and location of wells to be drilled, completed or turned-in-line, the number and type of drilling rigs, the number and type of frac crews, and the availability of capital to complete these plans and programs); the projected scope and timing of the Company's combo-development projects; estimated reserves and inventory duration; projected production and sales volumes and growth rates; natural gas prices, changes in basis and the impact of commodity prices on the Company's business; projected breakeven price, average well costs and gathering rates; the Company's ability to successfully implement, execute and achieve the intended benefits from its operational, organizational, technological and ESG initiatives, including the Company's emissions targets and the timing thereof; infrastructure projects; monetization transactions, including asset sales, joint ventures or other transactions involving the Company's assets, and the Company's planned use of the proceeds from any such monetization transactions; potential acquisitions or other strategic transactions, the timing thereof and the Company's ability to achieve the intended operational, financial and strategic benefits from any such transactions; the amount and timing of any repayments, redemptions or repurchases of the Company's common stock, outstanding debt securities or other debt instruments; the Company's ability to reduce its debt and the timing of such reductions, if any; the projected amount and timing of dividends; projected cash flows, adjusted operating cash flow, free cash flow and free cash flow yield; projected capital expenditures; projected adjusted EBITDA; liquidity and financing requirements, including funding sources and availability; the Company's ability to maintain or improve its credit ratings, leverage levels and financial profile; the Company's hedging strategy and projected margin posting obligations; and the effects of litigation, government regulation and tax position.

These forward-looking statements involve risks and uncertainties that could cause actual results to differ materially from projected results. Accordingly, investors should not place undue reliance on forward-looking statements as a prediction of actual results. The Company has based these forward-looking statements on current expectations and assumptions about future events, taking into account all information currently available to the Company. While the Company considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks and uncertainties, many of which are difficult to predict and beyond the Company's control and which include, but are not limited to, volatility of commodity prices; the costs and results of drilling and operations; uncertainties about estimates of reserves, identification of drilling locations and the ability to add proved reserves in the future; the assumptions underlying production forecasts; the quality of technical data; the Company's ability to appropriately allocate capital and other resources among its strategic opportunities; access to and cost of capital; the Company's hedging and other financial contracts; inherent hazards and risks normally incidental to drilling for, producing, transporting and storing natural gas, natural gas liquids and oil; cyber security risks; availability and cost of drilling rigs, completion services, equipment, supplies, personnel, oilfield services and water required to execute the Company's exploration and development plans, including as a result of the COVID-19 pandemic; risks associated with operating primarily in the Appalachian Basin and obtaining a substantial amount of the Company's midstream services from Equitrans Midstream; the ability to obtain environmental and other permits and the timing thereof; government regulation or action, including regulations pertaining to methane and other greenhouse gas emissions; negative public perception of the fossil fuels industry; increased consumer demand for alternatives to natural gas; environmental and weather risks, including the possible impacts of climate change; and disruptions to the Company's business due to acquisitions and other strategic transactions. These and other risks and uncertainties are described under Item 1A, "Risk Factors," of the Company's Annual Report on Form 10-K for the year ended December 31, 2020 as filed with the SEC and the Company's Annual Report on Form 10-K for the year ended December 31, 2021 to be filed with the SEC, as updated by any subsequent Form 10-Qs, and those set forth in other documents the Company files from time to time with the SEC.

Any forward-looking statement speaks only as of the date on which such statement is made, and the Company does not intend to correct or update any forward-looking statement, whether as a result of new information, future events or otherwise, except as required by law.

This presentation also refers to adjusted EBITDA, adjusted operating cash flow, free cash flow, free cash flow yield, free cash flow per share and net debt calculations and ratios. These non-GAAP financial measures are not alternatives to GAAP measures and should not be considered in isolation or as an alternative for analysis of the Company's results as reported under GAAP. For additional disclosures regarding these non-GAAP measures, including definitions of these terms and reconciliations to the most directly comparable GAAP measurers, please refer to the appendix of this presentation.

The Premier Appalachian Natural Gas Producer

A compelling opportunity to invest in America's premier natural gas assets

FINANCIAL PROFILE

~125%
FCF[1] through 2026 of current market cap[2]

1.0 – 1.5x
Leverage[1] target before 2023

~20%
2022 FCF Yield[1,2]

~30%
2023 FCF Yield[1,2]

~2.5%
Fixed dividend Yield[2]

NYSE: EQT

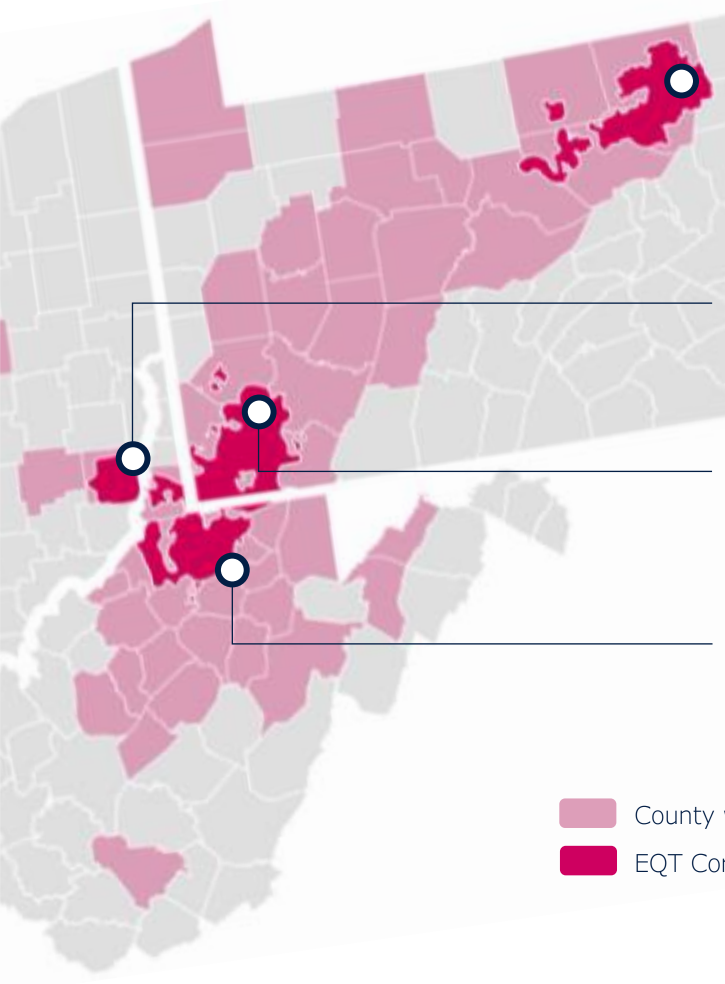
CORPORATE PROFILE	
Market capitalization[2]	$8.0 B
Net debt[1,2]	$5.4 B
Enterprise value[2]	$13.4 B
Liquidity[2]	$2.2 B
Core net Marcellus acres[2]	~940,000 Acres
Core net locations	~1,800
Core net lateral feet	>22 MM Ft.
2022E daily volumes	~5.5 Bcfe/d
Natural Gas Production Mix	~95%

1. *Non-GAAP measure. See appendix for definition.*
2. *Share prices in calculations as of 1/31/2022; net debt, liquidity, and acreage as of 12/31/2021.*

Multi-Decade Inventory of High-Quality Natural Gas Assets

Combination of scale, premier assets, and responsible development

PURE-PLAY APPALACHIAN PRODUCER



NE PA MARCELLUS
~1.0 Bcf/d
~180k core net acres

OH UTICA
~0.5 Bcfe/d
~70k core net acres

SWPA MARCELLUS
~3.3 Bcfe/d
~470k core net acres

WV MARCELLUS
~0.8 Bcf/d
~290k core net acres

County w/ EQT Acreage
EQT Core Acreage

MEASURING OUR IMPACT

#1
Producer of natural gas in the United States[1]

>1,800
Core net locations
(over 15 years of maintenance pace)

Since 2005, EQT contributed to
~5%
of total GHG emissions reductions in the U.S.
(total U.S. solar industry ~6%)

If EQT were a country, it would be the
12th
largest producer in the world[2]
(~25 Tcf of proved reserves)

Pure-Play Appalachian E&P with
4.0 Bcf/d
of certified gas[3]
(largest amongst peers)

Net Zero
By or before 2025[4]
(among the fastest in the industry)

1. *Source: EIA*
2. *Source: IHS Markit*
3. *Based on production from wells certified under the EO100TM Standard for Responsible Energy Development and the MiQ methane standard*
4. *Net zero on a Scope 1 and 2 basis for EQT's production segment operations and based on assets owned by EQT as of 6/30/2021.*

Robust Free Cash Flow Profile Generation

Compelling growth in free cash flow generation and free cash flow yield **while in maintenance mode**

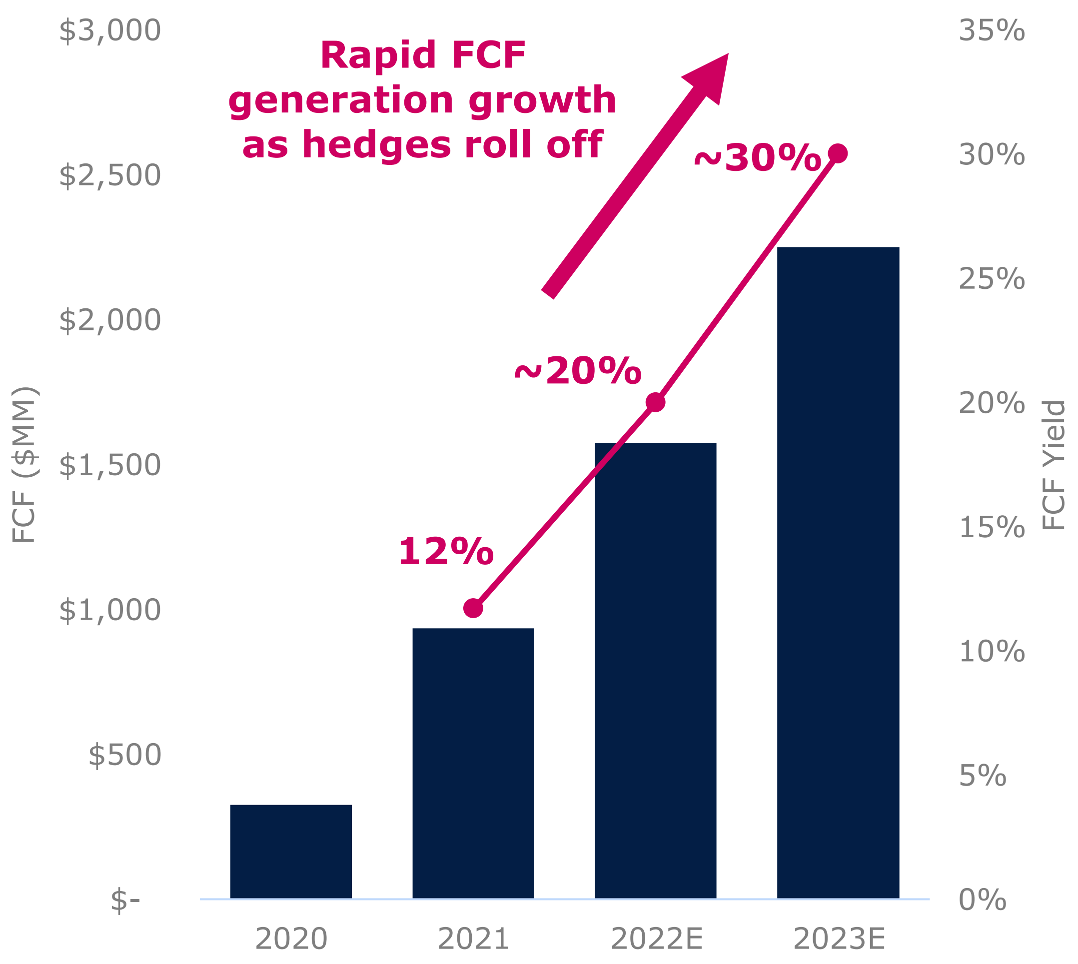
$10+ Billion

of free cash flow[1,2] generation
2021 through 2026

Factors Driving Improved Free Cash Flow Generation:

Base Plan	Upside
• Contracted gathering rates decline by ~$0.18/mcfe long-term	• Continued operational improvements
• Improving land capital spending	• Credit upgrades reduce interest expense & cost of capital
• Shallowing base decline rate	• Improved pricing driven by premiums for RSG
• Breakeven price projected to improve by ~30% by 2026 from 2019 levels	• Commodity price improvements • Every $0.10 increase in Realized Price = $200 MM of incremental FCF[1] on an unhedged basis and excluding cash taxes

FCF GENERATION[1] & FCF YIELD[1,3]



1. Non-GAAP measure. See appendix for definition.
2. Uses strip pricing as of 1/31/2022.
3. Share price as of 1/31/2022.

Capital Allocation Framework Drives Value for our Shareholders

Operational improvements and financial strength have positioned EQT to begin returning capital

CAPITAL ALLOCATION FRAMEWORK *PRIORITIES & PRINCIPLES*	**NEAR-TERM ACTION** (2022-2023)	**LONG-TERM TARGETS** (2023+)
$1.5 B IN ABSOLUTE DEBT REDUCTION Commitment to attaining investment grade metrics; Paid down ~$206 MM in principle in January 2022	**$1.5 B** In debt retirement by year-end 2023	**1.0x – 1.5x** Long-term leverage[1] target[2]
+		
$1.0 B SHARE REPURCHASE PROGRAM Through year-end 2023; Repurchased ~2.5 million shares since 12/13/21 announcement	**$1.0 B** In effect	**Opportunity to Increase**
+		
FIXED ANNUAL DIVIDEND OF $0.50/SHARE ~2.5% 2022E yield[3]; paid quarterly beginning in 1Q22	**$0.50/share** $0.125/share quarterly, starting in 1Q22	**Opportunity to Grow**
+		
RETAINED FLEXIBILITY Net of planned and executed capital allocation	**~40%** Retained Flexibility[4]	**Opportunity to Optimize**

1. *Non-GAAP measure. See appendix for definition.*
2. *Using a conservative $2.75 gas price.*
3. *Share price as of 1/31/2022.*
4. *At strip as of 1/31/2021.*

Foundational Shareholder Return Program Is Another Completed Milestone

After being voted in by shareholders in 2019, management has been delivering on promises

CHECKED ALL BOXES IN SUSTAINABLE SHALE ERA

- Premier Asset Base and Efficient Operations
- Free Cash Flow Generation
- Balance Sheet Strength
- Emissions Reductions
- Returning Capital

MILESTONES

July 2019

- ✓ Shareholders overwhelmingly voted for current management
- ✓ Implemented proven modern operating model
- ✓ Streamlined corporate structure and lowered costs

2020

- ✓ Executed win-win consolidated gathering agreement with ETRN to reduce long-term gathering costs
- ✓ Embarked on de-leveraging strategy
- ✓ Executed accretive Chevron Marcellus asset acquisition
- ✓ Removed near-term maturity wall

2021

- ✓ Partnered with EO/MiQ to build portfolio of responsibly sourced gas (RSG)
- ✓ Executed accretive NEPA Alta acquisition
- ✓ Established aggressive emissions reduction targets
- ✓ Laid groundwork for sustainable shareholder returns

2022

The Call for Clean Energy Is a Call on EQT

The call on low-emissions natural gas provides exciting upside opportunity

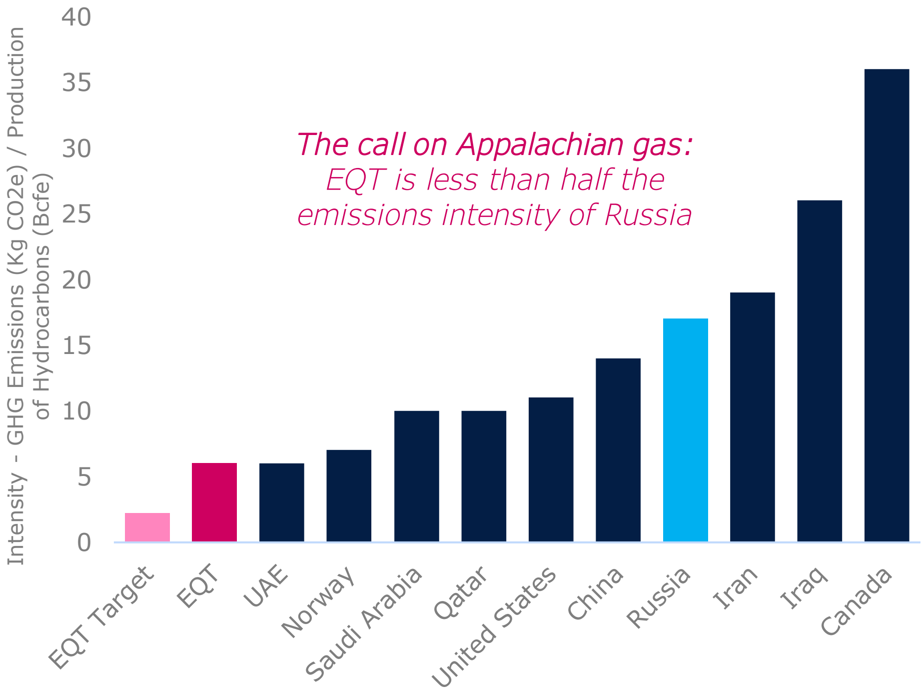
NATURAL GAS MACRO TAILWINDS

- Peers are demonstrating disciplined capital allocation, flattening supply growth
- Growing appreciation for the need for U.S. LNG to play a meaningful role in addressing climate change

Global coal represents
~25%
of the total primary energy consumption mix in 2025[1]

This equates to
~430 Bcfe/d
of natural gas consumption, essentially double what the market consumes today

2020 EMISSIONS INTENSITY[2]



EQT NATURAL GAS PRICE UPSIDE

- Hedging program designed to protect shareholder returns and balance sheet while providing substantial price upside
- Obtaining investment grade rating will open opportunities for LNG contracting with pricing upside

<$2.30
per MMBtu
average corporate breakeven[3]
through 2026

~$0.50
In FCF[4] per share
for every $0.10 increase in realized price on an unhedged basis

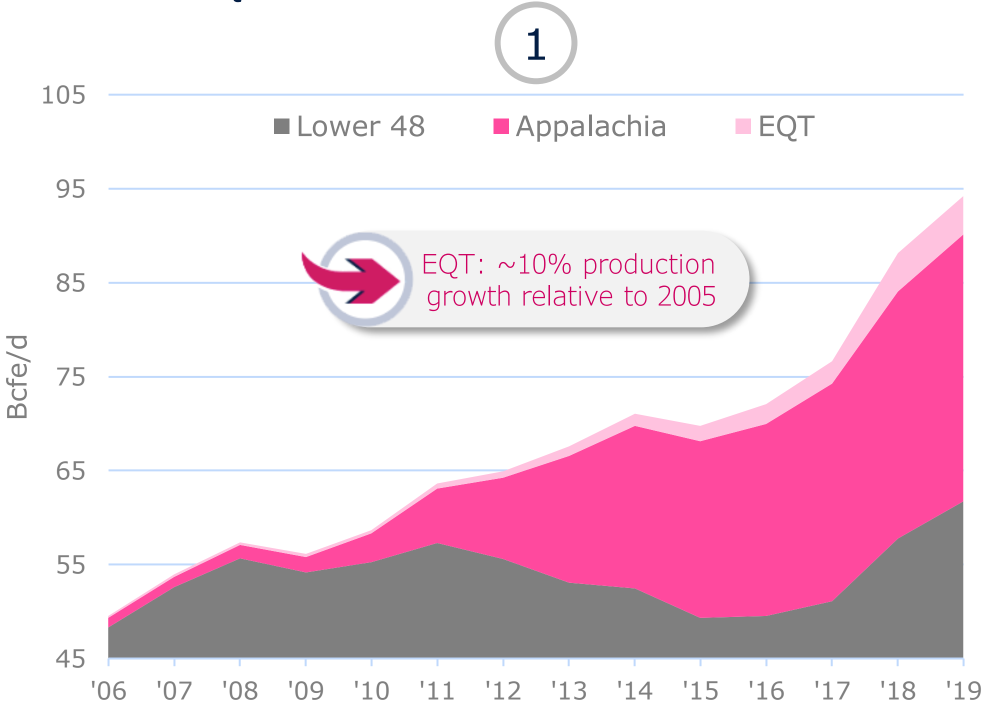
1. *Source: EIA*
2. *Source: Rystad*
3. *Defined as the Henry Hub prices needed to generate positive free cash flow under a maintenance production plan; assumes ($0.50) average differential and excludes cash taxes*
4. *Non-GAAP measure. See appendix for definition.*

Natural Gas Is the Fastest, Most Effective Way to Lower Emissions

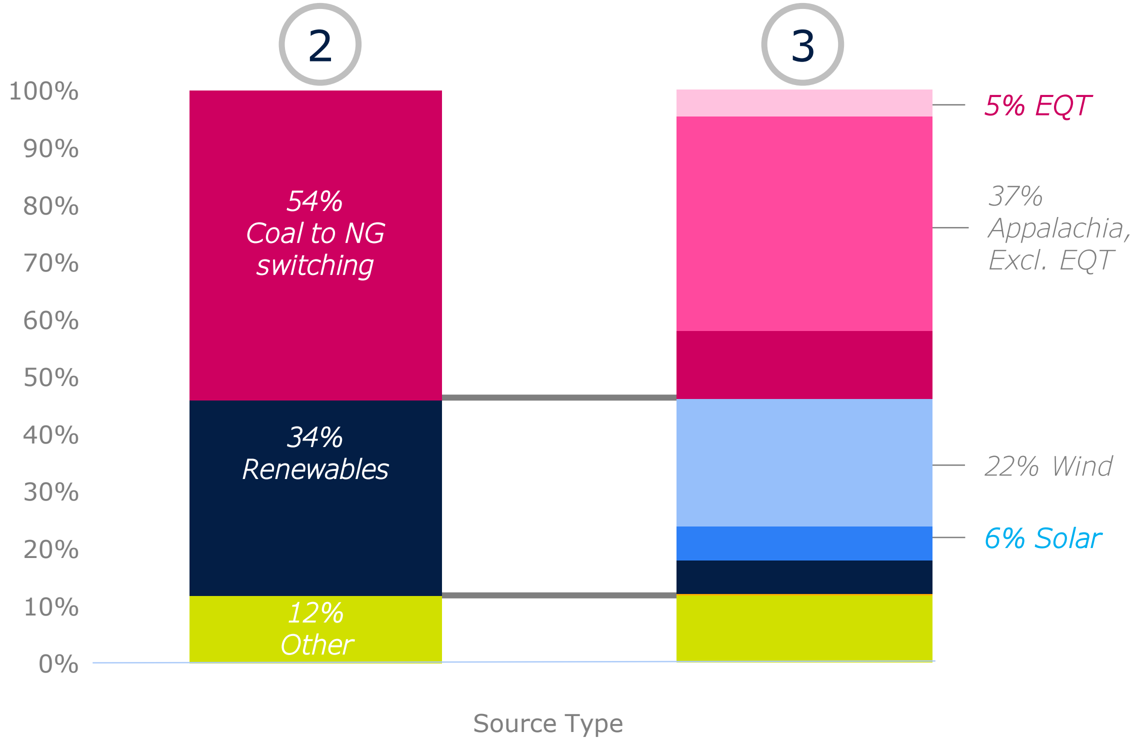
Since 2005, EQT has facilitated emissions reductions roughly equal to that of the entire solar industry

1. EQT represented approximately 10% of natural gas production growth from 2005 to 2019
2. Incremental natural gas production relative to 2005 enabled coal to gas switching, resulting in over half of the 970 mmMT of emissions reductions in the U.S.(1)
3. EQT is one of, if not the, largest single contributors to emissions reduction in the U.S. over this period, with an emissions reduction contribution of 5%

NATURAL GAS PRODUCTION(2)
Lower 48 vs. EQT



EMISSIONS REDUCTION % BY SOURCE(3)
Percent of reduction of the 970 mmMt



1. Source: EIA
2. Source: WoodMackenzie
3. EQT calculations based on EIA data

EQT Presents a Differentiated Energy Investment Opportunity

Expanding track record of performance and continuing our rate of change story

DO IT RIGHT…			…THEN DO IT BETTER
EQT Strength	Detail	Stat	Upside and Benefits
PROVEN MANAGEMENT TEAM	Modern operating model, data-driven operations, & implementation of combo-development approach	→ *Reduced corporate breakeven[1] from $2.90 to <$2.30 (average through 2026) since management joined*	Robust science program aimed at further enhancing drilling economics
PREMIER ASSET BASE	Appalachian pure-play natural gas producer with low capital intensity & low emissions intensity	→ *Approximately 940,000 core net Marcellus acres, 4-5 rigs to hold 2.0 Tcfe production flat* → *~1,800 core net locations and ~22 million gross lateral feet of inventory provides decades of core inventory and repeatable performance*	Best current opportunity is buying our own stock
ROBUST FREE CASH FLOW GENERATION	Significant long-term FCF profile under maintenance production profile	→ *~$1.8 B of average annual free cash flow[1] 2022 through 2026; $10+ B total from 2021 through 2026*	Hedging strategy provides balanced risk-adjusted upside to free cash flow
BALANCE SHEET STRENGTH	Expected investment grade metrics by mid-year 2022	→ *Debt trades closer to investment grade peers than high yield peers*	Unlocking ability to sign long-term sales agreements and lowering our cost of capital
ESG LEADERSHIP	Peer-leading emissions reduction targets	→ *Net zero by or before 2025[2]; Anticipated 70% reduction in GHG emissions intensity[3] by or before 2025*	Unlocking opportunities with direct RSG sales
RETURN OF CAPITAL PROGRAM	Shareholder returns competitive with the S&P 500	→ *$1.0 B share repurchase authorization, $0.50 annual base dividend*	Preserved flexibility leaves opportunity for more shareholder returns

1. *Defined as the Henry Hub prices needed to generate positive free cash flow under a maintenance production plan; assumes ($0.50) average differential and excludes cash taxes*
2. *Non-GAAP measure. See appendix for definition.*
3. *Net zero on a Scope 1 and 2 basis for EQT's production segment operations and based on assets owned by EQT as of 6/30/2021.*
4. *As compared to 2018. 2018 EQT GHG emissions data does not include Scope 2 GHG emissions, as we began calculating our Scope 2 GHG emissions in 2020.*

Creating Long-Term, Sustainable Value

Simple value proposition

*"Our story is simple: we have evolved our business to align with the core tenants of a sustainable shale era. That means running a **maintenance production profile** that is sustainable for the commodity, implementing a **hedge strategy** that provides the best risk-adjusted upside in natural gas, continuing to **generate meaningful and sustainable free cash flow**, and **returning that cash flow to our shareholders** through our base dividend and share repurchases.*

*We can do this all while **being good stewards** of the environment, of our local communities, and by benefitting domestic and international energy-users by **producing affordable, clean, reliable energy.**"*

- TOBY Z. RICE, PRESIDENT & CEO

1 Maintenance capital program to produce ~2 Tcfe

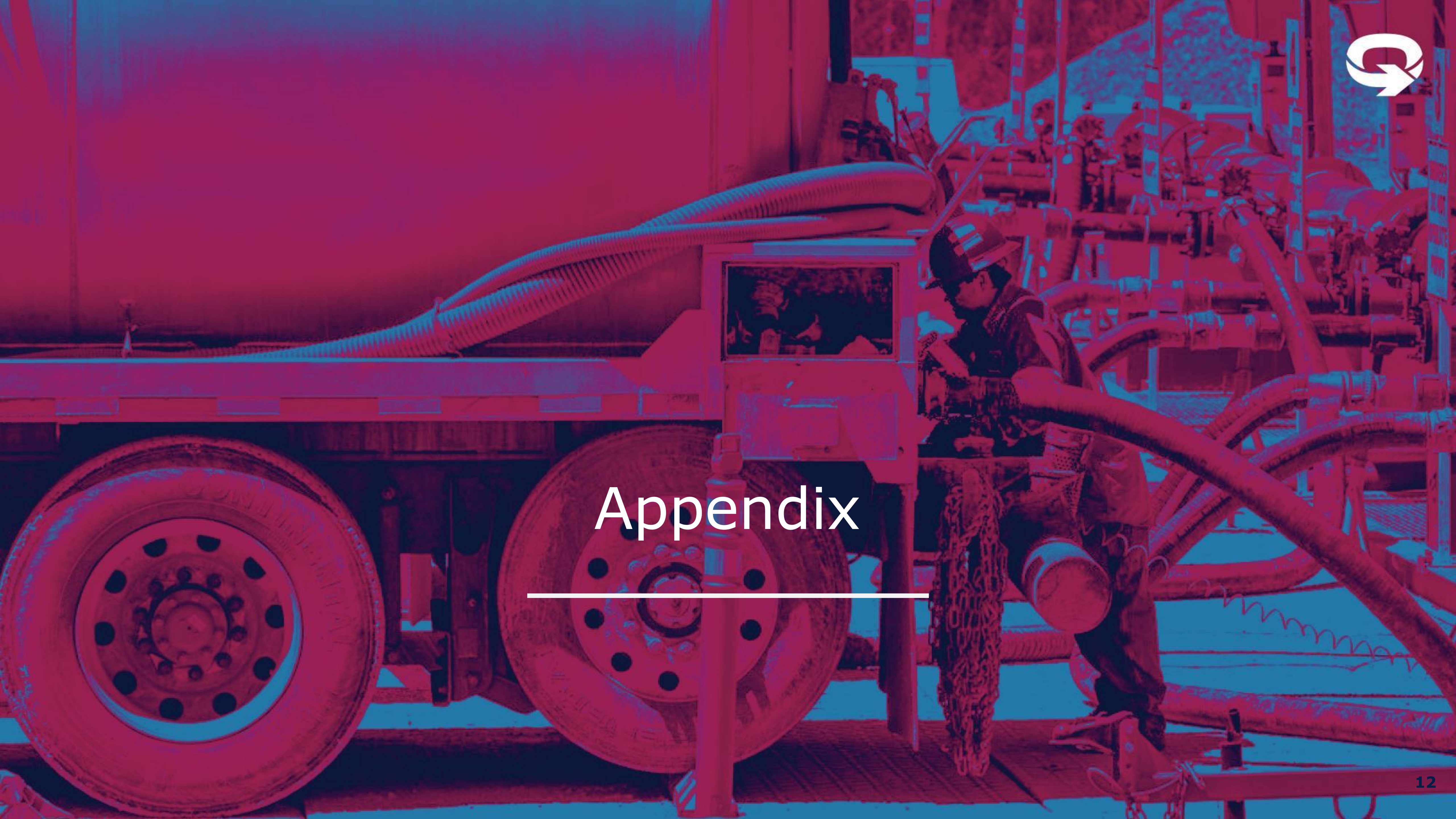
2 Hedging strategy that provides downside protection while providing substantial upside exposure

3 Expect to generate $10+ B in free cash flow(1) from 2021 through 2026, ~125% of our current market cap(2)

4 Annual base dividend of $0.50/share and up to $1.0 B in share repurchase ability, with flexibility to grow

5 Long-term leverage(1) target of 1.0 to 1.5x using $2.75/MMBtu price

1. Non-GAAP measure. See appendix for definition.
2. Share price as of 1/31/2022.



Appendix

Maintaining Momentum into 2022 and Beyond

Demonstrating consistent improvement under maintenance production profile

		2020	2021	2022E			'23+ TREND
Net Sales Volumes	**Bcfe/d**	4.1	5.1 Alta acquisition July 2021	**5.4**	**-**	**5.6**	**Maintenance**
OPEX[(1)]	**$/Mcfe**	$1.36	$1.27	**$1.25**	**-**	**$1.37**	**Improving**
Adj. EBITDA[(2)]	**$B**	$1.5	$2.3	**$3.10**	**-**	**$3.30**	**Improving**
CAPEX	**$B**	$1.1	$1.1	**$1.30**	**-**	**$1.45**	**Improving**
CAPEX Efficiency (CAPEX/Sales Volumes)	**$/Mcfe**	$0.72	$0.59	**$0.65**	**-**	**$0.75**	**Improving**
Maintenance Intensity (CAPEX/OCF)		77%	54%	**40%**	**-**	**50%**	**Improving**
FCF[(2)] (1/31/22 Strip)	**$B**	$0.3	$0.9	**$1.40**	**-**	**$1.75**	**Improving**
YE Leverage[(3)]		3.2x	2.3x	**1.3x**	**-**	**1.5x**	**Improving**

1. *Operating expenses include gathering, transportation, processing, LOE, production taxes, and SG&A*
2. *Non-GAAP measure. See appendix for definition.*
3. *Leverage is defined as year-end net debt divided by last-twelve-month (LTM) adjusted EBITDA; For 2022E guidance, leverage uses expected EBITDA. Net debt and adjusted EBITDA are non-GAAP financial measures. See the non-GAAP disclosures section of this presentation for the definition of, and other important information regarding these measures.*

2022 Capital Program Details

Reflects full-year impact of Alta acquisition, phase-in of next generation well design and expected ~10% cost inflation

Capital Expenditures – ($MM)	2021A	2022E
Reserve Development[1]	$828	$1,010 - $1,110
Land and lease[2]	$144	$110 - $130
Other	$74	$120 - $160
Capitalized Overhead	$58	$55 - $75
Total CAPEX[2]	**$1,104**	**$1,300 - $1,450**

Net Sales Volume (Bcfe)	1,858	1,950 – 2,050
Res Dev Capital Efficiency ($/Mcfe) (Res Dev CAPEX / Volumes), excl. next gen well design CAPEX	$0.45	$0.47 – 0.54

Res Dev CAPEX (%)	2022E
SWPA	~55%
NEPA	~15%
WV	~30%
OH	<1%

Land CAPEX[2] ($MM)	
Leasehold Maintenance	$45 - $55
In-fill Leasing and Mineral Purchasing	$65 - $75

Other CAPEX ($MM)	
Asset Maintenance[3]	$80 - $100
Capitalized Interest	$20 - $30
Midstream	$20 - $30

1. *Includes ~$50 MM related to development of next generation well design in 2022 .*
2. *Excludes amounts attributable to noncontrolling interests.*
3. *Includes site compliance, well tubing installs, facilities, and operational IT.*

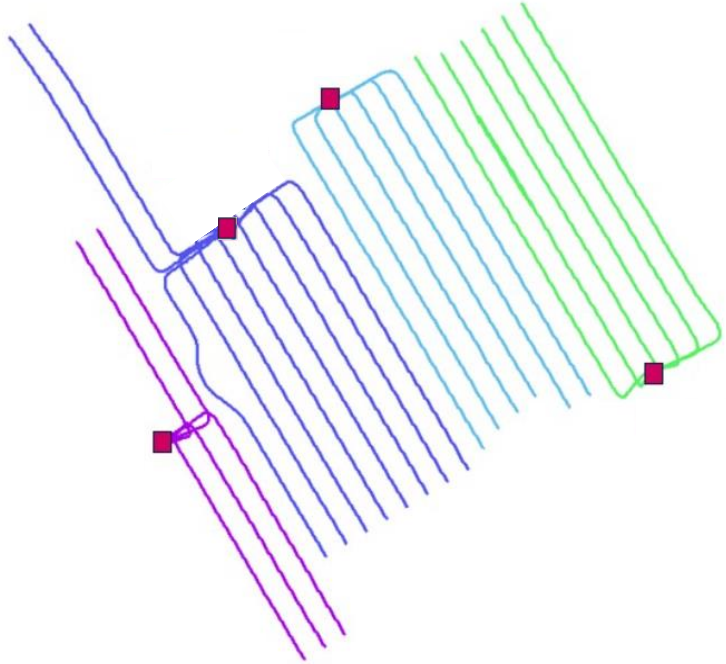
Leveraging Large-Scale Operations on a Large-Scale Asset Base

Highly predictable & repeatable operations through combo-development

EQT COMBO-DEVELOPMENT EXAMPLE

REQUIREMENTS
- Contiguous asset base
- Standardized designs
- Coordinated planning between groups
- Long line-of-sight on operations

REAL RESULTS
- ~8,300 acres
- 4 pads
- 27 wells
- 360,000+ lateral feet
- ~600 mmcfe/d of total volume impact[(1)]



CAT PHROG COMBO - GREENE COUNTY, PA

1. *Inclusive of standard flat time on wells.*

>80%
Combo-development planned through 2026

>15
Years of core net locations mapped out

2.0 Tcfe
Held flat with 4-5 rigs and ~$1.0 B in total D&C CAPEX

MODERN WELL PADS COMBINE SCALE AND EFFICIENCY

- Combo-development: large-scale, simultaneous development of multiple wells and pads
- Pads built for 18-25 wells each to produce >250,000 lateral feet

MAXIMIZING RESOURCE, IMPROVING PRODUCTIVITY & REDUCING COSTS

- Standardized well designs drive repeatable long-term results, optimize well productivity and maximize long-term asset value
- Next generation well design aimed at further improving the value of our wells
  - ~$50 MM of planned capital in 2022
- Investment in water infrastructure in WV has resulted in cost savings
- Line-of sight in operations translates into shared upside with service providers

ESG BENEFITS

- Improved drilling and completions efficiencies materially lower Scope 1 & 2 GHG emissions
- Full use of electric frac fleets and hybrid drilling rigs improves performance and lowers emissions and environmental disturbance
- WV fresh-water system improves cost & ESG performance

Our Modern Operating Model Has Driven a Step-Change in Asset Performance

We are now realizing the full impact of productivity improvements from our operational overhaul

Operational Overhaul: Implementation of best practices and process standardization has driven:

~98% Production uptime

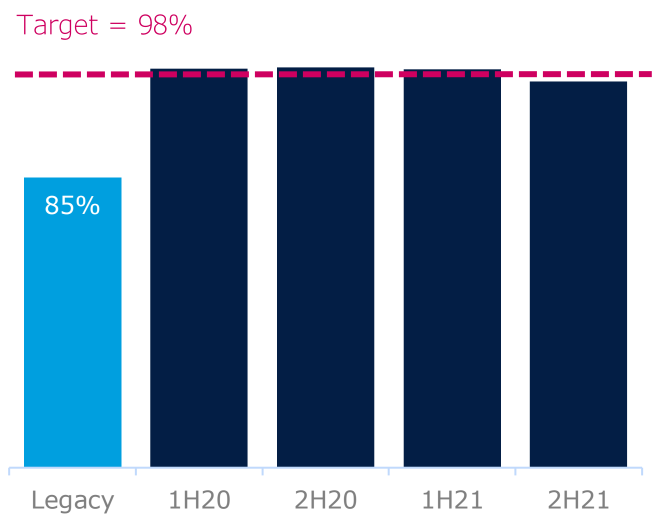
&

~40% Improvement in Marcellus EURs

Increased EURs + Lower Well Costs = Improving F&D

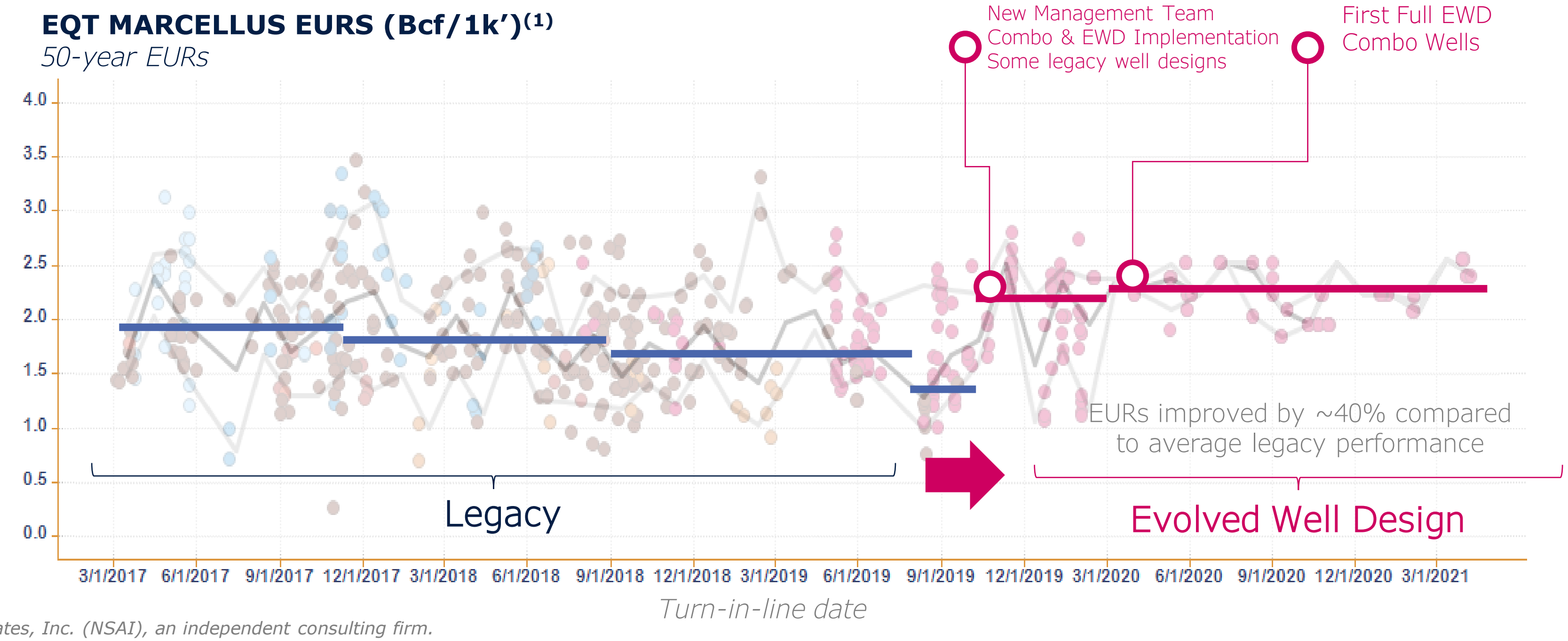
Maximizing Production Uptime → Modern Well Design & Standardization → Repeatable Results & Value Creation

PRODUCTION UPTIME



EQT MARCELLUS EURS (Bcf/1k')[1]

50-year EURs



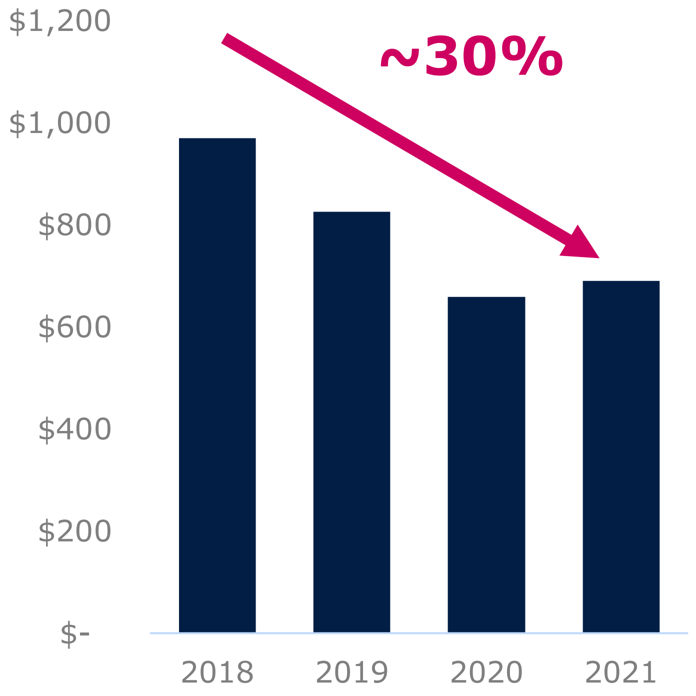
1. *EURs and reserve information are audited by Netherland, Sewell & Associates, Inc. (NSAI), an independent consulting firm.*

Continuing the Rate of Change on Operational and Cost Improvements

Strong track record and methodical science program gives us confidence to begin phasing in next generation well design

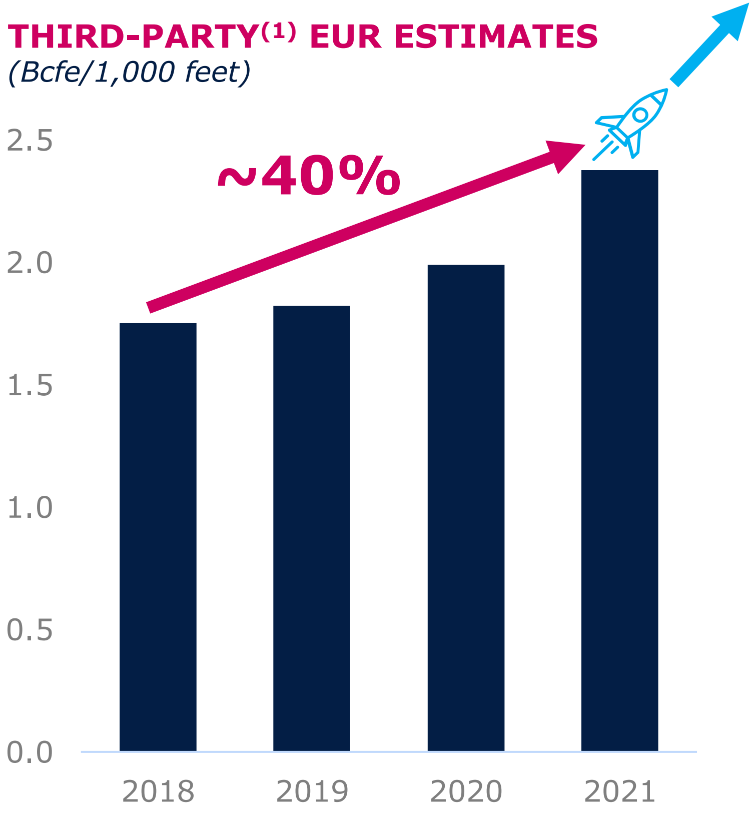
DECREASED COSTS

EQT COST PER FOOT
($/ft) – PA Marcellus



IMPROVED PRODUCTIVITY

THIRD-PARTY[(1)] EUR ESTIMATES
(Bcfe/1,000 feet)



Operational Improvements
+
Standardized Well Design
+
Highly Coordinated Operations
+
Methodical Science Program
=

Development of Next Gen Well Design
(~$50 MM investment in 2022)

Increased FCF & Maximum Value Generation

1. Source: Enverus. EUR performance looks at Marcellus Tier 1 SW PA Dry and Marcellus Tier 2 SW PA Dry.

The Marcellus Is the Most Capital Efficient Gas Play

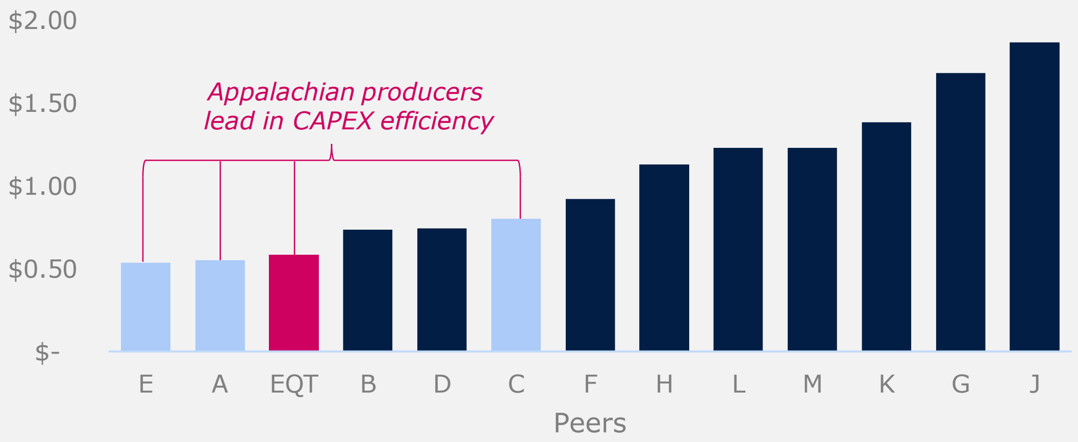
EQT's capital efficiency will continue to improve over time, with only 5 rigs needed to hold production flat in 2022

THE MARCELLUS ADVANTAGE

- Less capital intensity on maintenance production profile
- In 2022, we see the Marcellus experiencing less inflationary pressures vs. what is being seen in the Haynesville and Permian
- We expect our capital efficiency to remain robust for the long-term due to our deep core inventory, shallowing corporate decline rate and operational efficiency gains

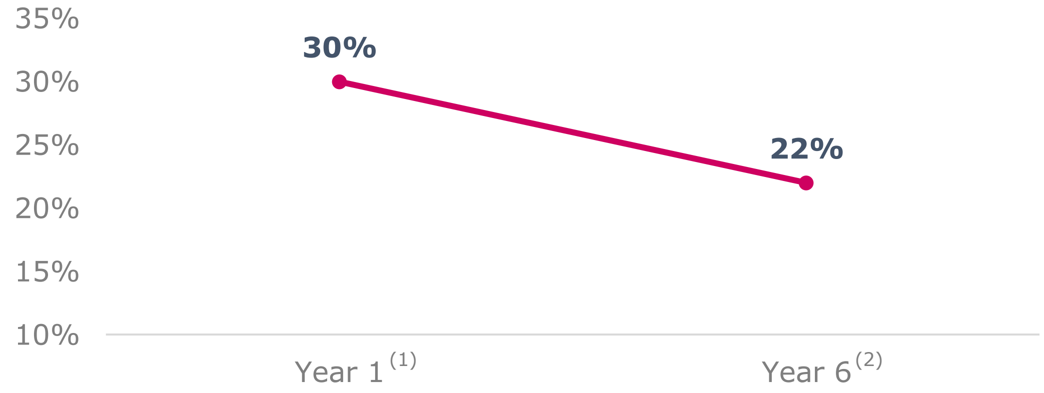
2021E CAPEX EFFICIENCY VS. PEERS[3]

2021E CAPITAL EXPENDITURES / 2021E SALES VOLUMES ($/MCFE)



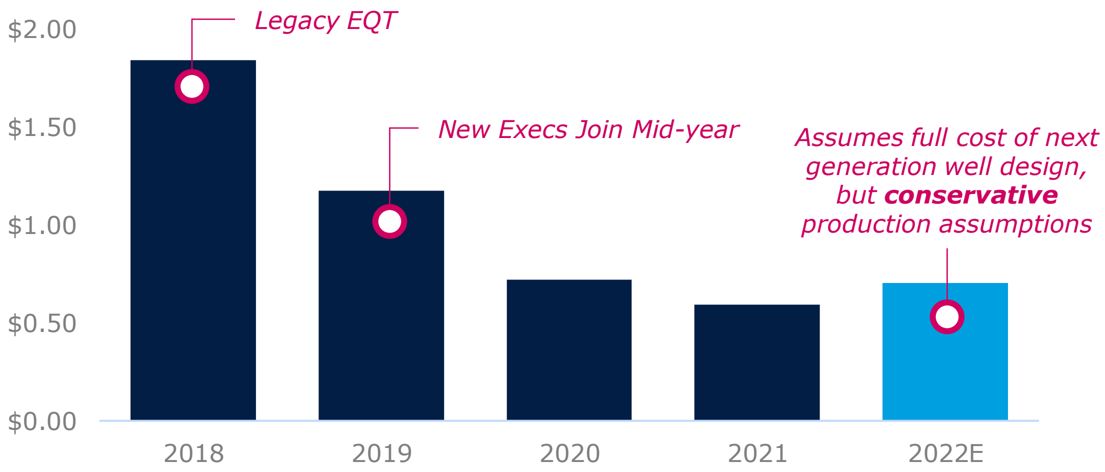
EQT BASE DECLINE RATE

EXIT-TO-EXIT RATE DECLINE



EQT CAPEX EFFICIENCY OVER TIME

CAPITAL EXPENDITURES/SALES VOLUMES ($/MCFE)



1. *Year 1 reflects all producing wells as of 12/31/2021.*
2. *Year 6 reflects all producing wells planned as of 12/31/2026.*
3. *Source: Factset consensus estimates as of 1/24/2022. Peers include AR, CHK, CNX, CTRA, RRC, SWN, MGY, OXY, PXD, FANG, PDCE, & OVV.*

We Have Line of Sight to an Investment Grade Rating

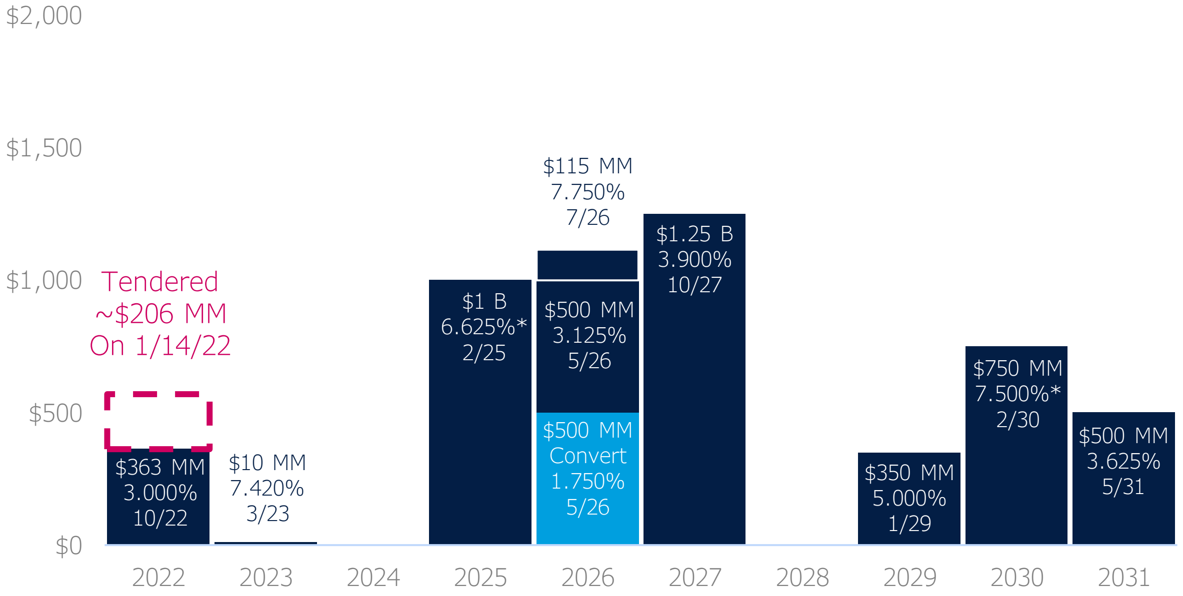
Near-term FCF exceeds debt maturities, providing ample financial flexibility

$10+ B of cumulative free cash flow[1,2] 2021 through 2026 **>** **~$2.5 B** of maturities through 2026

- Long-term leverage[2] target of 1.0 – 1.5x
- Line of sight to 1.3 – 1.5x leverage[2] by year-end 2022[1]
- Investment grade rating reduces cost of capital and maximizes financial flexibility

$B	12/31/21	12/31/20
Cash & Cash Equivalents	$0.1	-
Current Portion of Debt	$1.0	$0.2
Note Payable to EQM Midstream Partners	$0.1	$0.1
$2.5 B Senior Unsecured Revolver	-	$0.3
LT Debt (Bonds)	$4.4	$4.4
Total Debt	$5.5	$4.9
Net Debt[2]	$5.4	$4.9
LTM Leverage[2]	2.3x	3.2x

EQT SENIOR NOTES MATURITIES[3]



Rates are applicable to the interest payment on February 1, 2022.

Credit Ratings as of February 4, 2022			
Rating Agency	Senior Notes	Notches to IG	Outlook
Moody's	Ba1	1	Stable
S&P	BB+	1	Positive
Fitch	BB+	1	Stable

1. *Uses strip as of 1/31/2022.*
2. *Non-GAAP measure. See appendix for definition.*
3. *Principal value and interest rates as of 12/31/2021. 2022 debt highlights tender executed on 1/14/2022.*

Ample Liquidity Results in Strong Capital Allocation Ability

Return to investment grade would further improve liquidity position

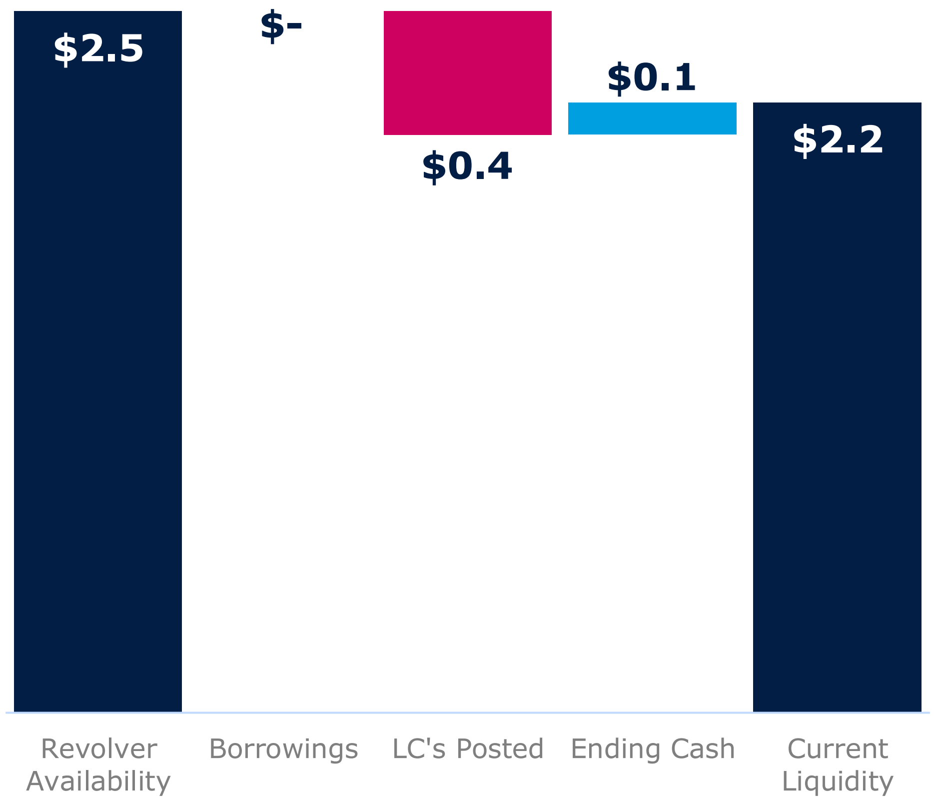
$2.5 B
Unsecured Revolver

- April 23, 2021: Entered into a one-year extension agreement
- Commercial terms remain relatively unchanged
- Demonstrates banks' comfort in financial positioning
- Not subject to semi-annual borrow base redeterminations

~$2.2 B
Liquidity[1]

- Fitch, S&P and Moody's Credit Rating upgrades set the stage for improved liquidity
- Returning to Investment Grade would eliminate LC's
- Up ~$0.9 B since 9/30, largely due to margin posting reversions

LIQUIDITY[1]



1. *As of 12/31/2021.*

Hedging Strategy Provides Risk-Adjusted Upside

Hedge position as of February 4, 2022

UPDATED HEDGING STRATEGY

- Implementing a hedge strategy that provides the best risk-adjusted upside in natural gas
- 2021 and prior balance sheet improvements have allowed us to shift from being defensive to more balanced
- Locks in FCF to allow us to execute our shareholder return strategy with confidence

~65%

Hedged in 2022

	2022 1Q	2022 2Q	2022 3Q	2022 4Q	2023	2024
Hedged Volume (MMDth)	355	329	287	287	858	16
Hedged Volume (MMDth/d)	3.9	3.6	3.1	3.1	2.4	-
NYMEX Swaps (Includes Futures)						
Volume (MMDth)	289	296	254	232	166	2
Avg. Price ($/Dth)	$2.78	$2.63	$2.41	$2.36	$2.53	$2.67
CALLS - NET SHORT						
Volume (MMDth)	57	101	102	102	606	15
Avg. Short Strike ($/Dth)	$3.26	$3.00	$3.00	$3.00	$4.38	$3.11
PUTS - NET LONG						
Volume (MMDth)	65	32	32	54	689	15
Avg. Long Strike ($/Dth)	$2.68	$2.68	$2.68	$2.68	$2.90	$2.45
FIXED PRICE SALES[1]						
Volume (MMDth)	1	1	1	1	3	-
Avg. Price ($/Dth)	$2.38	$2.38	$2.38	$2.38	$2.38	-

1. *The difference between the fixed price and NYMEX price is included in average differential presented in the Company's price reconciliation.*

Advantaged Market Intelligence & Diversified End Markets

Access to diverse markets provides flexibility and opportunity

Provides Operational and Cash Flow Flexibility

- Diversity of delivery markets provides significant commercial optionality
- Firm transportation portfolio acts as a long-term basis hedge

Improves Netback Pricing

- Rationalizing our firm transportation portfolio to improve realizations
  - → *Secured 205 MMDth/d of premium REX capacity in 3Q21*
- Portfolio offers price stability by accessing highly liquid markets

Bottoms-Up Macro View Leads to Optimized Planning

- Assets directly access markets with growing demand
- Ability to quickly capture market opportunities
- Leveraging network for RSG initiatives

Market Mix - Price Points	2022E	2023E
Local	42%	35%
Covered[3]	63%	
Exposed	37%	
East[1]	16%	22%
Covered	83%	
Exposed	17%	
Midwest	18%	18%
Covered	24%	
Exposed	76%	
Gulf	25%	25%
Covered	8%	
Exposed	92%	
Total	100%	100%
Total Basis Exposure	~50%	
Realization[2]	**2022E**	**2023E**
Avg. FT Cost ($/Mcfe)	($0.30)	($0.35)
Average Differential[3] ($/Mcf)	($0.63)	($0.53)
Net Realization ($/Mcfe)	($0.93)	($0.87)

We hedge local basis

~15%

Of total volumes exposed to local pricing in 2022

~$30 MM

movement in 2022 free cash flow[4] for every $0.10 move in local pricing

1. "East" includes what was previously shown as "Southeast", which assumes mid-year 2023 MVP in-service.
2. Reflects midpoint of guidance ranges. See guidance slide for further details.
3. Covered volumes include basis swaps, physical sales and fixed price sales.

Ability to Drive Meaningful ESG Rate of Change

Proven leadership: 2021 ESG accomplishments

ENVIRONMENTAL

- Publicly supported reinstating the Federal Methane Rule
- Partnered with Cheniere and others to advance GHG emissions monitoring technologies
- Joined OGMP 2.0 initiative
- Announced net zero ambitions that are among the fastest within the industry
- Implemented $75 MM capital program aimed at ESG focused projects
- Obtained Equitable Origin/MiQ Certifications for ~4.0 Bcf/d of our produced gas

SOCIAL

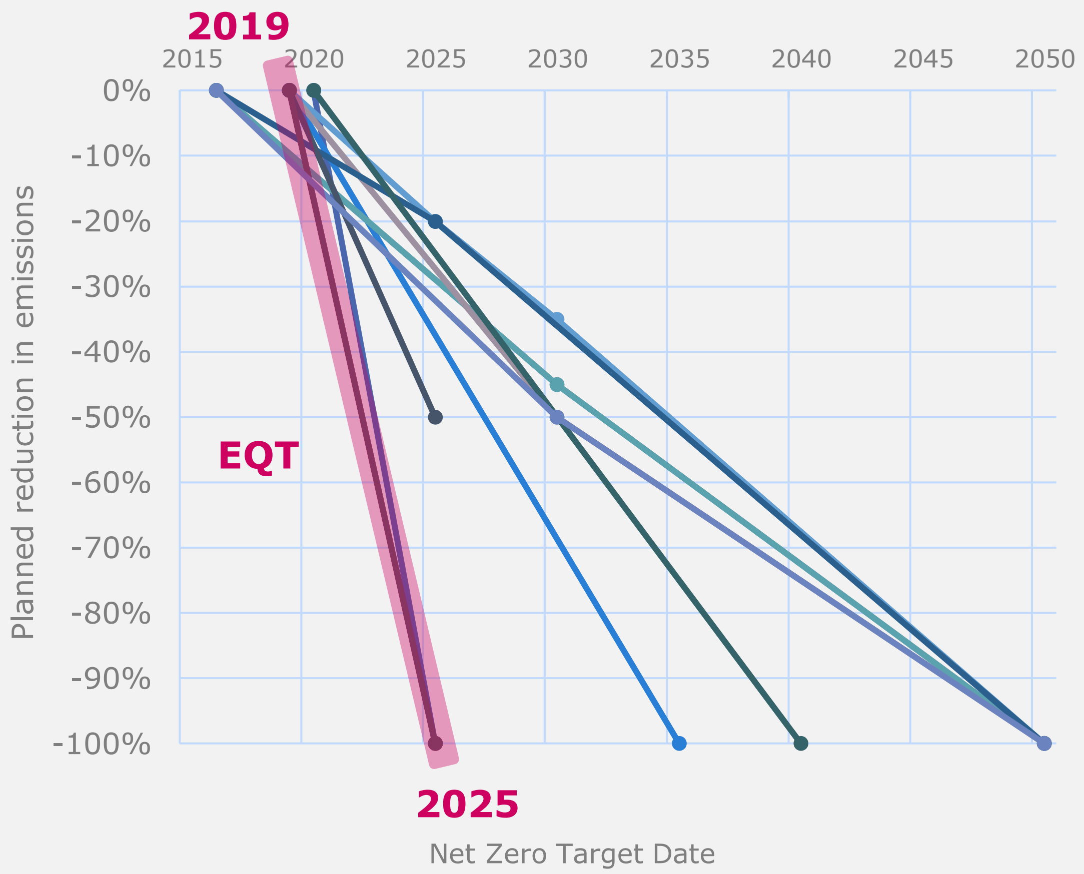
- Held first ever ESG focused conference call to provide transparency on initiatives and increase engagement opportunities for investment community
- $735 MM in royalties paid to local communities
- Launched new giving programs for Greene and Wetzel Counties, PA
- Named as a National Top Workplace for 2021

GOVERNANCE

- Recognized for advancing women's leadership and Board diversity
  - Board and all four Committees chaired by women
  - Increased minority representation on Board
- Leveraging digital work environment to track over 2,000 metrics, ensuring transparency and accountability for achieving performance goals

NET ZERO TARGETS [1]

EQT vs. Peers[2]



1. Source: Rystad Energy
2. Companies include AR, BP, CHK, COP, CVX, DVN, HES, MRO, OXY, RDS, RRC, & XOM

Demonstrating Environmental Commitment and Leadership

Our initiatives our impactful, recognized by key environmental stakeholders, and available for industry adoption

INITIATIVE: PNEUMATIC VALVE REPLACEMENT

HIGH IMPACT
- EQT: Full-scale replacement of >8,000 natural gas driven pneumatic devices in 2022
  → *Expected to reduce EQT's methane emissions intensity by ~65% versus 2018 levels*

LOW COST
- Total project cost ~$20 MM; one-time expense
  → *Translates to $0.01 per Mcfe in 2022*

SHARING OUR BEST PRACTICES
- Pneumatics are estimated to account for over 35% of the U.S. oil and gas sector's methane emissions
  → *We believe a substantial majority of these emissions are abatable at a relatively low cost*

"Furthermore, several oil and gas operators are already transitioning to zero-emitting pneumatic controllers on their own, without EPA or state regulations. ***EQT, the largest natural gas producer in the country, with operations in Pennsylvania, West Virginia, and Ohio, is transitioning its fleet of 8,000 pneumatic controllers to zero-emitting devices.*** *The company has committed to completing that process by the end of 2022 and anticipates an over 50% reduction in methane emissions as a result."*

EDF ENVIRONMENTAL DEFENSE FUND

2/1/2022

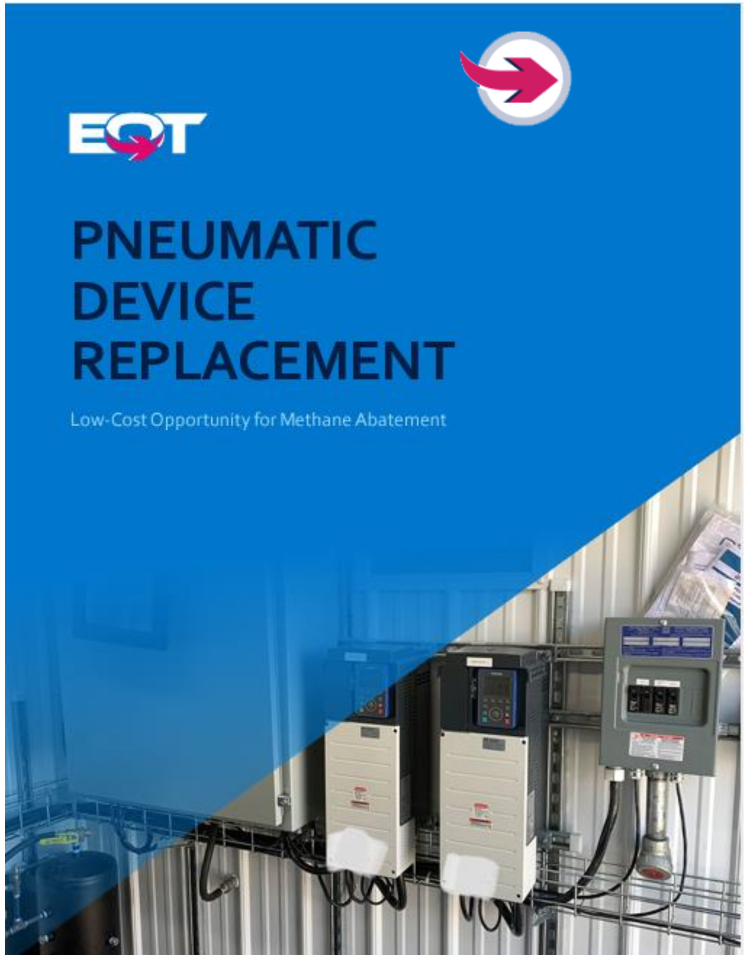
INITIATIVE: RESPONSIBLY SOURCED GAS (RSG)

SUBSTANTIAL RESOURCE
- EQT is the largest producer of RSG in the U.S.
  → *~4.0 Bcf/d certified*
  → *Obtained Equitable Origin/MiQ certifications in November 2021*

GROWING DEMAND
- Signed multiple RSG related deals at premium index pricing
- Gas utilities, power generators and international LNG operators are expressing strong interest

EQT PUBLICATION[1]

Published in January 2022 – available to industry



1. *For reference, please visit: https://www.eqt.com/responsibility/pneumatic-device-replacement/*

EQT Is Changing the World That We Touch

Our operational presence within local communities makes a tremendous impact

AMERICAN SHALE: A NEW HOPE
Digital Wildcatters

455,313 video views
40,000 hours of watch time

- Documentary that explores how the natural gas industry is giving new hope to American farmers.
- Follows the journey of Cain Farms, which revolutionized its operations by adding automation
- Live premiere in December featured EQT CEO Toby Rice, Larry Cain and Digital Wildcatters

There are thousands of similar stories thanks to American shale

>$1 Billion
Royalties paid to landowners during the pandemic years of 2020 & 2021

>$53 MM
Philanthropic contributions, infrastructure investments and state impact fees in 2021

>6,900 Hours
Volunteered by EQT employees in local communities

Pricing, Acquisitions & Strong Operations Increased Total Proved Reserves

Year-end 2021 reserve highlights

+26%	**INCREASE IN TOTAL PROVED RESERVES**
+440%	**INCREASE IN PROVED RESERVE PV10[1,2]**
158%	**PROVED DEVELOPED REPLACEMENT RATIO** *Excluding the impact of the Alta acquisition*
$0.37 per mcfe	**PROVED UNDEVELOPED NET FINDING & DEVELOPMENT COST (F&D)**
3.75 years	**BOOKING IN 5-YEAR PLAN** *Over 4 million WI net lateral feet*

Proved Reserves by Play (Bcfe)	Year Ended 12/31	
	2021	**2020**
Proved developed reserves		
Marcellus	15,528	11,943
Upper Devonian	806	839
Ohio Utica	787	757
Other	98	102
Total	**17,219**	**13,641**
Proved developed BTAX PV10[1,2] - $MM	**$15,958**	**$3,699**
Proved undeveloped reserves		
Marcellus	7,733	6,061
Ohio Utica	10	100
Total	**7,743**	**6,161**
Total Proved Reserves	**24,962**	**19,802**
Total BTAX PV10[1,2] - $MM	**$21,496**	**$3,967**

1. *Non-GAAP measure. See the appendix for definition.*
2. *Year-end 2021 reserves are based on a $3.598 per MMBtu natural gas price (NYMEX), which is $1.61 higher than the price used to estimate 2020 reserves. Prices are determined in accordance with the SEC requirement to use the unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months without giving effect to derivative transactions.*

2022 Guidance

Production	Q1 2022	Full-Year 2022
Total sales volume (Bcfe)	475 – 525	1,950 – 2,050
Liquids sales volume, excluding ethane (Mbbls)	2,835 – 2,935	10,820 – 11,320
Ethane sales volume (Mbbls)	1,475 - 1,575	6,600 – 6,700
Total liquids sales volume (Mbbls)	4,310 - 4,510	17,420 – 18,020
Btu uplift (MMbtu / Mcf)		1.045 - 1.055
Average differential ($ / Mcf)	($0.45) - ($0.35)	($0.75) - ($0.50)
Resource Counts		
Top-hole Rigs		1 – 2
Horizontal Rigs		2 – 3
Frac Crews		2 – 3
Per Unit Operating Costs ($ / Mcfe)		
Gathering	$0.64 - $0.66	$0.66 - $0.68
Transmission	$0.28 - $0.30	$0.29 - $0.31
Processing	$0.09 - $0.11	$0.08 - $0.10
LOE, excluding production taxes	$0.07 - $0.09	$0.08 - $0.10
Production taxes	$0.04 - $0.06	$0.04 - $0.06
SG&A	$0.10 - $0.12	$0.10 - $0.12
Total per unit operating costs	$1.22 - $1.34	$1.25 - $1.37
Financial ($ Billions)		
Adjusted EBITDA[1,2]		$3.100 - $3.300
Adjusted operating cash flow[1,2]		$2.950 – $3.150
Capital expenditures	$0.300 - $0.350	$1.300 - $1.450
Free cash flow[1,2]		$1.400 - $1.750

1. *Based on NYMEX natural gas price of $4.81 per Mmbtu as of 1/31/2022.*
2. *Non-GAAP measure. See appendix for definition.*

Well Activity Details

4Q21 actuals, 1Q22 and FY22 estimates

Wells Drilled (SPUD)

	SWPA Marcellus			NEPA Marcellus			WV Marcellus			OH Utica		
	4Q21A	1Q22E	FY22E	4Q21A	1Q22E	FY22E	4Q21A	1Q22E	FY22E	4Q21A	1Q22E	FY22E
Net Wells	-	11-15	39-47	11	4-6	19-23	9	-	5-6	-	-	-
Net Avg. Lateral (1k ft.)	-	12.8-14.2	12.3-13.6	10.1	10.4-11.5	12.5-13.8	14.2	-	14.0-15.5	-	-	-

Wells Horizontally Drilled

	SWPA Marcellus			NEPA Marcellus			WV Marcellus			OH Utica		
	4Q21A	1Q22E	FY22E	4Q21A	1Q22E	FY22E	4Q21A	1Q22E	FY22E	4Q21A	1Q22E	FY22E
Net Wells	28	2-3	36-44	6	4-6	25-31	-	8-11	20-25	-	0-1	0-1
Net Avg. Lateral (1k ft.)	11.5	9.8-10.8	12.0-13.2	11.9	10.3-11.4	10.9-12.1	-	16.1-17.8	14.7-16.3	-	14.6-16.2	14.6-16.2

Wells Completed (Frac)

	SWPA Marcellus			NEPA Marcellus			WV Marcellus			OH Utica		
	4Q21A	1Q22E	FY22E	4Q21A	1Q22E	FY22E	4Q21A	1Q22E	FY22E	4Q21A	1Q22E	FY22E
Net Wells	4	15-20	57-70	3	2-3	12-15	8	5-7	22-27	-	0-1	0-1
Net Avg. Lateral (1k ft.)	14.7	13.0-14.4	12.2-13.4	8.9	10.9-12.1	10.0-11.0	12.2	12.0-13.2	11.5-12.7	-	11.4-12.5	12.2-13.5

Wells Turned-in-Line (TIL)

	SWPA Marcellus			NEPA Marcellus			WV Marcellus			OH Utica		
	4Q21A	1Q22E	FY22E	4Q21A	1Q22E	FY22E	4Q21A	1Q22E	FY22E	4Q21A	1Q22E	FY22E
Net Wells	12	9-12	56-69	6	1-2	10-13	8	5-6	22-27	-	-	0-1
Net Avg. Lateral (1k ft.)	12.5	14.4-15.9	12.2-13.5	9.7	10.0-11.1	10.3-11.3	12.2	11.9-13.2	11.5-12.7	-	-	12.2-13.5

Non-GAAP Financial Measure

Adjusted EBITDA

Adjusted EBITDA is defined as net loss, excluding interest expense, income tax benefit, depreciation and depletion, amortization of intangible assets, (gain) loss on sale/exchange of long-lived assets, impairments, the revenue impact of changes in the fair value of derivative instruments prior to settlement and certain other items that impact comparability between periods. Adjusted EBITDA is a non-GAAP supplemental financial measure used by the Company's management to evaluate period-over-period earnings trends.

The Company's management believes that this measure provides useful information to external users of the Company's consolidated financial statements, such as industry analysts, lenders and ratings agencies. Management uses adjusted EBITDA to evaluate earnings trends because the measure reflects only the impact of settled derivative contracts; thus, the measure excludes the often-volatile revenue impact of changes in the fair value of derivative instruments prior to settlement. The measure also excludes other items that affect the comparability of results or that are not indicative of trends in the ongoing business. Adjusted EBITDA should not be considered as an alternative to net loss presented in accordance with GAAP.

Non-GAAP Financial Measure

Reconciliation of Adjusted EBITDA

The table below reconciles adjusted EBITDA with net income (loss), the most comparable financial measure as calculated in accordance with GAAP, as reported in the Statements of Consolidated Operations to be included in the Company's Annual Report on Form 10-K for the year ended December 31, 2021.

	Year Ended December 31, 2021	Year Ended December 31, 2020
	(thousands)	
Net income (loss)	$ (1,154,513)	$ (967,176)
Add (deduct):		
Interest expense	308,903	271,200
Income tax expense (benefit)	(434,175)	(298,858)
Depreciation and depletion	1,676,702	1,393,465
Amortization of intangible assets	—	26,006
(Gain) loss/impairment on sale/exchange of long-lived assets	(21,124)	100,729
Impairment of intangible and other assets	—	34,694
Impairment and expiration of leases	311,835	306,688
(Gain) loss on derivatives not designated as hedges	3,775,042	(400,214)
Net cash settlements (paid) received on derivatives not designated as hedges	(2,091,003)	897,190
Premiums (paid) received for derivatives that settled during the period	(67,809)	1,630
Other operating expenses (a)	70,063	28,537
Gain on Equitrans Share Exchange	—	(187,223)
(Income) loss from investments	(71,841)	314,468
Loss on debt extinguishment	9,756	25,435
Seismic data purchase	19,750	—
Adjusted EBITDA	$ 2,331,586	$ 1,546,571

(a) Other operating expenses includes transaction costs, reorganization costs, changes in legal reserves including settlements and other costs which affect the comparability of results or that are not indicative of trends in the ongoing business.

The Company has not provided projected net income (loss) or a reconciliation of projected adjusted EBITDA to projected net income (loss), the most comparable financial measure calculated in accordance with GAAP. Net income (loss) includes the impact of depreciation and depletion expense, income tax expense (benefit), the revenue impact of changes in the projected fair value of derivative instruments prior to settlement and certain other items that impact comparability between periods and the tax effect of such items, which may be significant and difficult to project with a reasonable degree of accuracy. Therefore, projected net income (loss), and a reconciliation of projected adjusted EBITDA to projected net income (loss), are not available without unreasonable effort.

Non-GAAP Financial Measure

Adjusted Operating Cash Flow, Free Cash Flow, Free Cash Flow Yield and Free Cash Flow Per Share

Adjusted operating cash flow is defined as net cash provided by operating activities less changes in other assets and liabilities. Free cash flow is defined as adjusted operating cash flow less accrual-based capital expenditures, excluding capital expenditures attributable to noncontrolling interests. Free cash flow yield is defined as free cash flow divided by market capitalization. Free cash flow per share is defined as free cash flow divided by weighted average common shares outstanding. Adjusted operating cash flow, free cash flow, free cash flow yield and free cash flow per share are non-GAAP supplemental financial measures used by the Company's management to assess liquidity, including the Company's ability to generate cash flow in excess of its capital requirements and return cash to shareholders. The Company's management believes that these measures provide useful information to external users of the Company's consolidated financial statements, such as industry analysts, lenders and ratings agencies. Adjusted operating cash flow, free cash flow, free cash flow yield and free cash flow per share should not be considered as alternatives to net cash provided by operating activities or any other measure of liquidity presented in accordance with GAAP.

The table below reconciles adjusted operating cash flow and free cash flow with net cash provided by operating activities, the most comparable financial measure calculated in accordance with GAAP, as derived from the Statements of Consolidated Cash Flows to be included in the Company's Annual Report on Form 10-K for the year ended December 31, 2021.

	Year Ended December 31,	
	2021	**2020**
	(thousands)	
Net cash provided by operating activities	$ 1,662,448	$ 1,537,701
Decrease (increase) in changes in other assets and liabilities	366,708	(139,178)
Adjusted operating cash flow	$ 2,029,156	$ 1,398,523
Less: capital expenditures	(1,104,114)	(1,078,788)
Add: capital expenditures attributable to noncontrolling interest	9,627	4,891
Free cash flow	$ 934,669	$ 324,626

The Company has not provided projected net cash provided by operating activities or reconciliations of projected adjusted operating cash flow, free cash flow, free cash flow yield and free cash flow per share to projected net cash provided by operating activities, the most comparable financial measure calculated in accordance with GAAP. The Company is unable to project net cash provided by operating activities for any future period because this metric includes the impact of changes in operating assets and liabilities related to the timing of cash receipts and disbursements that may not relate to the period in which the operating activities occurred. The Company is unable to project these timing differences with any reasonable degree of accuracy without unreasonable efforts such as predicting the timing of its payments and its customers' payments, with accuracy to a specific day, months in advance. Furthermore, the Company does not provide guidance with respect to its average realized price, among other items, that impact reconciling items between net cash provided by operating activities and adjusted operating cash flow, free cash flow, free cash flow yield and free cash flow per share, as applicable. Natural gas prices are volatile and out of the Company's control, and the timing of transactions and the income tax effects of future transactions and other items are difficult to accurately predict. Therefore, the Company is unable to provide projected net cash provided by operating activities, or the related reconciliations of projected adjusted operating cash flow, free cash flow, free cash flow yield and free cash flow per share to projected net cash provided by operating activities, without unreasonable effort.

Non-GAAP Financial Measure

Net Debt and Leverage

Net debt is defined as total debt less cash and cash equivalents. Total debt includes the Company's current portion of debt, credit facility borrowings, senior notes and note payable to EQM Midstream Partners, LP. Leverage is defined as net debt divided by adjusted EBITDA. Net debt is a non-GAAP supplemental financial measure used by the Company's management to evaluate leverage since the Company could choose to use its cash and cash equivalents to retire debt. The Company's management believes that this measure provides useful information to external users of the Company's consolidated financial statements, such as industry analysts, lenders and ratings agencies. Net debt should not be considered as an alternative to total debt presented in accordance with GAAP.

The table below reconciles net debt with total debt, the most comparable financial measure calculated in accordance with GAAP, as derived from the Statements of Condensed Consolidated Balance Sheets to be included in the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2021.

	December 31, 2021	December 31, 2020
	(Thousands)	
Current portion of debt (a)	$ 954,900	$ 154,161
Credit facility borrowings	—	300,000
Senior notes	4,435,782	4,371,467
Note payable to EQM Midstream Partners, LP	94,320	99,838
Total debt	5,485,002	4,925,466
Less: Cash and cash equivalents	113,963	18,210
Net debt (b)	$ 5,371,039	$ 4,907,256

(a) Pursuant to the terms of the Company's convertible senior notes indenture, a sale price condition for conversion of the convertible notes was satisfied as of December 31, 2021, and, accordingly, holders of convertible notes may convert any of their convertible notes, at their option, at any time during the quarter beginning on January 1, 2022 and ending on March 31, 2022, subject to all terms and conditions set forth in the convertible notes indenture. Therefore, as of December 31, 2021, the net carrying value of the liability portion of the Company's convertible notes of $381 million was included in current portion of debt in the Consolidated Balance Sheet. See the Company's Annual Report on Form 10-K for the year ended December 31, 2021 for further discussion.

(b) The Company will adopt new accounting guidance on January 1, 2022 which will change the amounts historically recorded for the Company's convertible senior notes. If this guidance would have been adopted as of December 31, 2021, net debt would have increased by $106 million. See the Company's Annual Report on Form 10-K for the year ended December 31, 2021 for further discussion.

The Company has not provided a reconciliation of projected net debt to projected total debt, the most comparable financial measure calculated in accordance with GAAP. The Company is unable to project total debt for any future period because total debt is dependent the timing of cash receipts and disbursements that may not relate to the periods in which the operating activities occurred. The Company is unable to project these timing differences with any reasonable degree of accuracy and therefore cannot reasonably determine the timing and payment of credit facility borrowings or other components of total debt without unreasonable effort. Furthermore, the Company does not provide guidance with respect to its average realized price, among other items that impact reconciling items between certain of the projected total debt and projected net debt, as applicable. Natural gas prices are volatile and out of the Company's control, and the timing of transactions and the distinction between cash on hand as compared to credit facility borrowings are too difficult to accurately predict. Therefore, the Company is unable to provide a reconciliation of projected net debt to projected total debt, without unreasonable effort.

Non-GAAP Financial Measure

PV10

PV-10 is derived from the standardized measure of discounted future net cash flows (the Standardized Measure), which is the most directly comparable financial measure computed using U.S. GAAP. PV-10 differs from Standardized Measure because it does not include the effects of income taxes on future net revenues. The Company's management believes the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to proved reserves held by companies without regard to the specific income tax characteristics of such entities and is a useful measure of evaluating the relative monetary significance of the Company's oil and natural gas properties. Investors may utilize PV-10 as a basis for comparing the relative size and value of the Company's proved reserves to other companies. PV-10 should not be considered as a substitute for, or more meaningful than, the Standardized Measure as determined in accordance with U.S. GAAP. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of the Company's oil and natural gas properties.

The table below reconciles PV-10 to the Standardized Measure, the most comparable financial measure calculated in accordance with GAAP, as derived from the footnotes to be included in the Company's Annual Report on Form 10-K for the year ended December 31, 2021.

	Year Ended December 31, 2021		
	Proved Developed	**Proved Undeveloped**	**Total**
		(Millions)	
Standardized measure of discounted future net cash flows	$ 13,192	$ 4,089	$ 17,281
Estimated income taxes on future net revenues	2,766	1,449	4,215
PV-10	$ 15,958	$ 5,538	$ 21,496

	Year Ended December 31, 2020		
	Proved Developed	**Proved Undeveloped**	**Total**
		(Millions)	
Standardized measure of discounted future net cash flows	$ 3,335	$ 31	$ 3,366
Estimated income taxes on future net revenues	364	237	601
PV-10	$ 3,699	$ 268	$ 3,967

Note: Reserves as of December 31, 2021 are based on a $3.598 per MMBtu for natural gas price (NYMEX). Prices are determined in accordance with the SEC requirement to use the unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months without giving effect to derivative transactions.