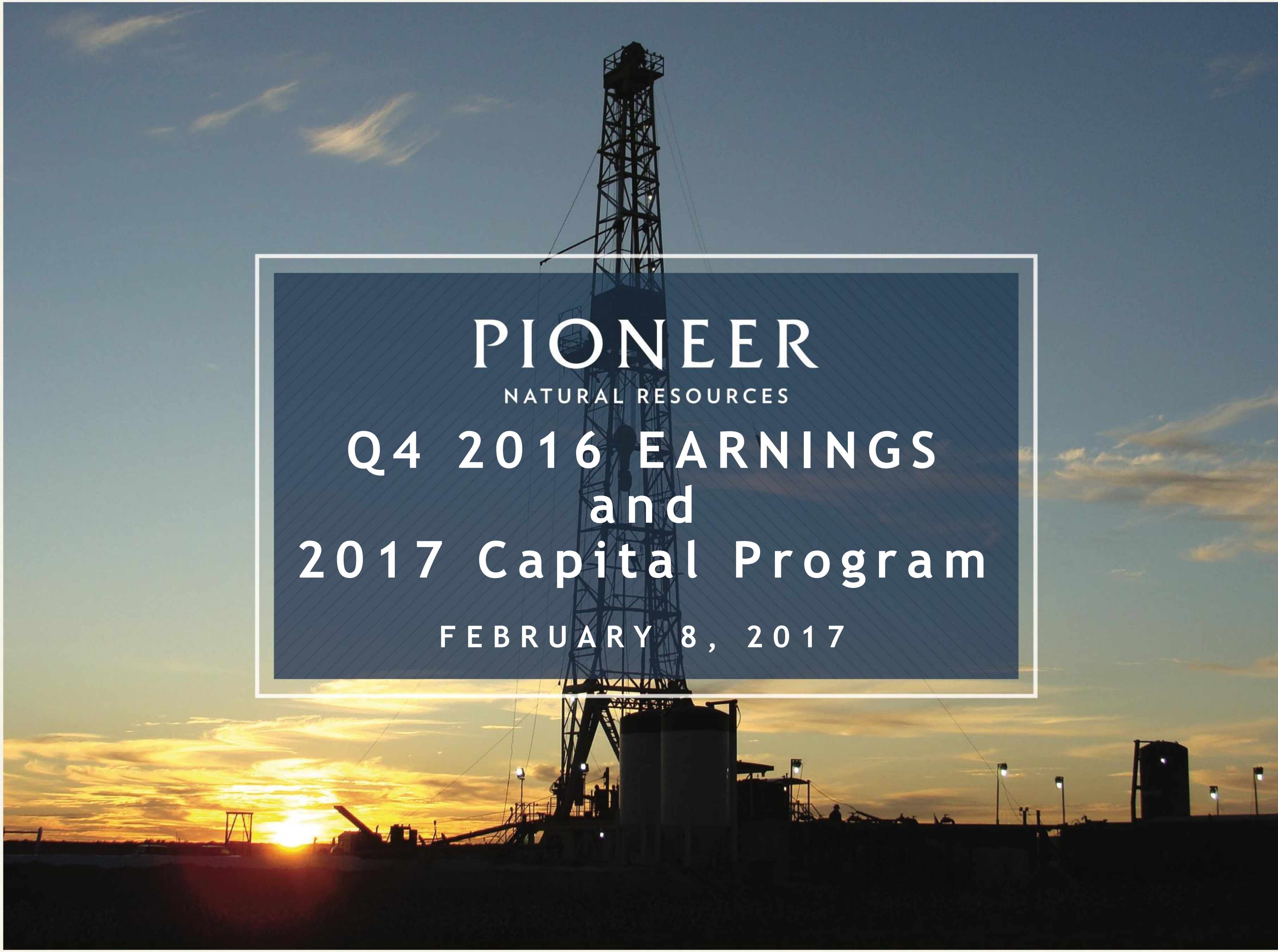


PIONEER
NATURAL RESOURCES

Q4 2016 EARNINGS and 2017 Capital Program

FEBRUARY 8, 2017

FORWARD-LOOKING STATEMENTS

Except for historical information contained herein, the statements in this presentation are forward-looking statements that are made pursuant to the Safe Harbor Provisions of the Private Securities Litigation Reform Act of 1995. Forward-looking statements and the business prospects of Pioneer are subject to a number of risks and uncertainties that may cause Pioneer's actual results in future periods to differ materially from the forward-looking statements. These risks and uncertainties include, among other things, volatility of commodity prices, product supply and demand, competition, the ability to obtain environmental and other permits and the timing thereof, other government regulation or action, the ability to obtain approvals from third parties and negotiate agreements with third parties on mutually acceptable terms, completion of planned divestitures, litigation, the costs and results of drilling and operations, availability of equipment, services, resources and personnel required to perform the Company's drilling and operating activities, access to and availability of transportation, processing, fractionation and refining facilities, Pioneer's ability to replace reserves, implement its business plans or complete its development activities as scheduled, access to and cost of capital, the financial strength of counterparties to Pioneer's credit facility, investment instruments, derivative contracts and the purchasers of Pioneer's oil, natural gas liquid and gas production, uncertainties about estimates of reserves and resource potential, identification of drilling locations and the ability to add proved reserves in the future, the assumptions underlying production forecasts, quality of technical data, environmental and weather risks, including the possible impacts of climate change, the risks associated with the ownership and operation of the Company's industrial sand mining and oilfield services businesses and acts of war or terrorism. These and other risks are described in Pioneer's Annual Report on Form 10-K for the year ended December 31, 2015, subsequent Quarterly Reports on Form 10-Q and other filings with the Securities and Exchange Commission. In addition, Pioneer may be subject to currently unforeseen risks that may have a materially adverse impact on it. Accordingly, no assurances can be given that the actual events and results will not be materially different than the anticipated results described in the forward-looking statements. Pioneer undertakes no duty to publicly update these statements except as required by law.

Please see the Supplemental Information slides included in this presentation for other important information.

FINANCIAL AND OPERATING HIGHLIGHTS

- **Q4 2016 adjusted income: $85 MM, or $0.49 per diluted share[1]**
- **Q4 2016 production: 242 MBOEPD (59% oil)**
  - Top end of Pioneer's guidance range of 237 MBOEPD to 242 MBOEPD
  - Increase of 3 MBOEPD vs. Q3 2016 (7th consecutive quarter of growth since downturn commenced)
- **FY 2016 production averaged 234 MBOEPD (57% oil vs. 52% in 2015)**
  - Increase of 30 MBOEPD, or 15%, vs. FY 2015
  - Oil production up 28 MBOPD, or 27%, vs. FY 2015
- **Growth driven by Spraberry/Wolfcamp horizontal drilling program**
  - Total Spraberry/Wolfcamp production increased by 36% vs. FY 2015 (oil production up 42%)
- **Reduced 2016 production costs per BOE by 29% compared to 2015**
  - Driven by cost reduction initiatives and growing low-cost Spraberry/Wolfcamp horizontal production
- **Delivered 232% drillbit reserve replacement (205 MMBOE) in 2016 at a drillbit F&D cost of $9.59 per BOE[2] and a proved developed F&D cost of $9.11 per BOE[3]**

1) Adjusted income and adjusted income per diluted share amounts are non-GAAP financial measures. See reconciliation in supplemental information slides
2) Excludes negative price revisions (58 MMBOE) and proved reserves added from acquisitions (4 MMBOE)
3) Reflects proved developed reserve additions of 213 MMBOE from (i) discoveries and extensions placed on production during 2016, (ii) transfers from proved undeveloped reserves at year-end 2015 and (iii) technical revisions of previous estimates for proved developed reserves during 2016. Revisions of previous estimates exclude price revisions

FINANCIAL AND OPERATING HIGHLIGHTS (CONT.)

- **Protected cash flow and margins through attractive oil and gas derivative positions during 2016; provided incremental cash receipts of $680 million**
- **Strong year-end balance sheet with $3 B of cash on hand[1]**
  - Net debt to 2016 operating cash flow of 0.2x and net debt-to-book capitalization of 2%
- **Increased northern Spraberry/Wolfcamp horizontal rig count from 12 rigs to 17 rigs during Q4, as expected**
- **Placed 66 horizontal wells on production in the Spraberry/Wolfcamp during Q4, as expected, with continuing strong performance (included 38 Version 3.0 wells)**
  - Version 3.0 completion optimization wells continue to outperform Version 2.0 wells
- **Continued to realize significant capital efficiency gains in the Spraberry/Wolfcamp**
  - Completion optimization and longer lateral lengths are continuing to enhance well productivity
  - Drilling and completion efficiencies continue to drive down cost per lateral foot
- **Signed agreement with the City of Midland to upgrade the City's wastewater treatment plant in return for a dedicated long-term supply of water from the plant**
- **Exported 525,000 barrels of Permian oil during Q4; expect to export two 525,000 barrel Permian oil cargoes to Asia during Q1**

1) Includes liquid investments

2017 PLAN AND CAPITAL PROGRAM

- **Plan to operate 18 horizontal rigs in the Spraberry/Wolfcamp during 2017**
  - 14 rigs in the northern area (13 rigs currently operating with an additional rig to be added in March)
  - 4 rigs in the southern Wolfcamp JV area; activity will be focused in the northern portion of the JV area (60% WI)
  - Completions will be predominantly Version 3.0
    - Planning to test larger completions during 2017
  - Spraberry/Wolfcamp production forecasted to grow by 30% to 34% compared to 2016, with oil production up 33% to 37%
- **Plan to complete 20 wells in the Eagle Ford Shale (9 DUCs and 11 new drills; 46% WI)**
  - Objective of limited new well program is to test longer laterals and higher intensity completions
- **Transferring West Panhandle gas processing operations from the Company's Fain plant to a third-party facility in March**
- **The 2017 drilling program is expected to deliver production growth ranging from 15% to 18% compared to 2016 (~62% oil compared to 57% oil in 2016)**
  - Expect IRRs ranging from 50% to 100% including facilities costs[1]

1) Based on $55/BBL oil price and $3/MCF gas price

2017 PLAN AND CAPITAL PROGRAM (CONT.)

- **2017 capital program of $2.8 B**
  - Includes $2.5 B for drilling and completions and $275 MM for vertical integration
  - Assumes ~5% cost inflation offset by efficiency gains; vertical integration expected to mitigate impact of 10% to 15% cost inflation forecasted for the industry in 2017
  - Program to be funded from forecasted cash flow of $2.2 B and cash on hand
- **Oil derivatives cover ~85% and gas derivatives cover ~55% of forecasted 2017 production**
- **Net debt to 2017 operating cash flow forecasted to remain below 1.0x**
- **High-grading Permian acreage position by agreeing to sell ~5,600 net acres in Upton and Andrews counties for $63 MM (before normal closing adjustments) in Q1; evaluating offers to sell ~20,500 net acres in Martin County**
  - Also opened a data room in late January to sell ~10,500 net acres in the Eagle Ford Shale

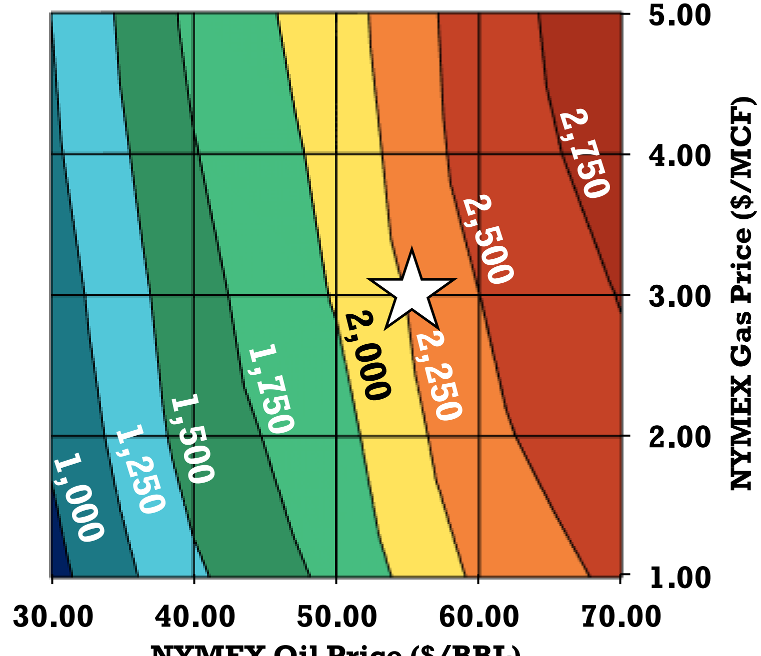
2017 program delivers strong high-return growth and positions Pioneer to spend within cash flow in 2018

2017 CAPITAL PROGRAM[1] AND CASH FLOW

2017 capital program of $2.8 B

- **Drilling and Completion Capital: $2.5 B**
  - $2.4 B Spraberry/Wolfcamp[2] (~95% of total)
    - $1.9 B for horizontal drilling program
    - $265 MM for tank batteries/SWDs
    - $115 MM for gas processing facilities
    - $110 MM for land/science/other
  - $95 MM Eagle Ford Shale
    - $65 MM for horizontal drilling program
    - $30 MM for compression/land/other
  - $20 MM Other Assets
- **Other Capital: $275 MM[3]**
- **Capital program funded from:**
  - Cash flow of $2.2 B
  - Cash on hand (including liquid investments)

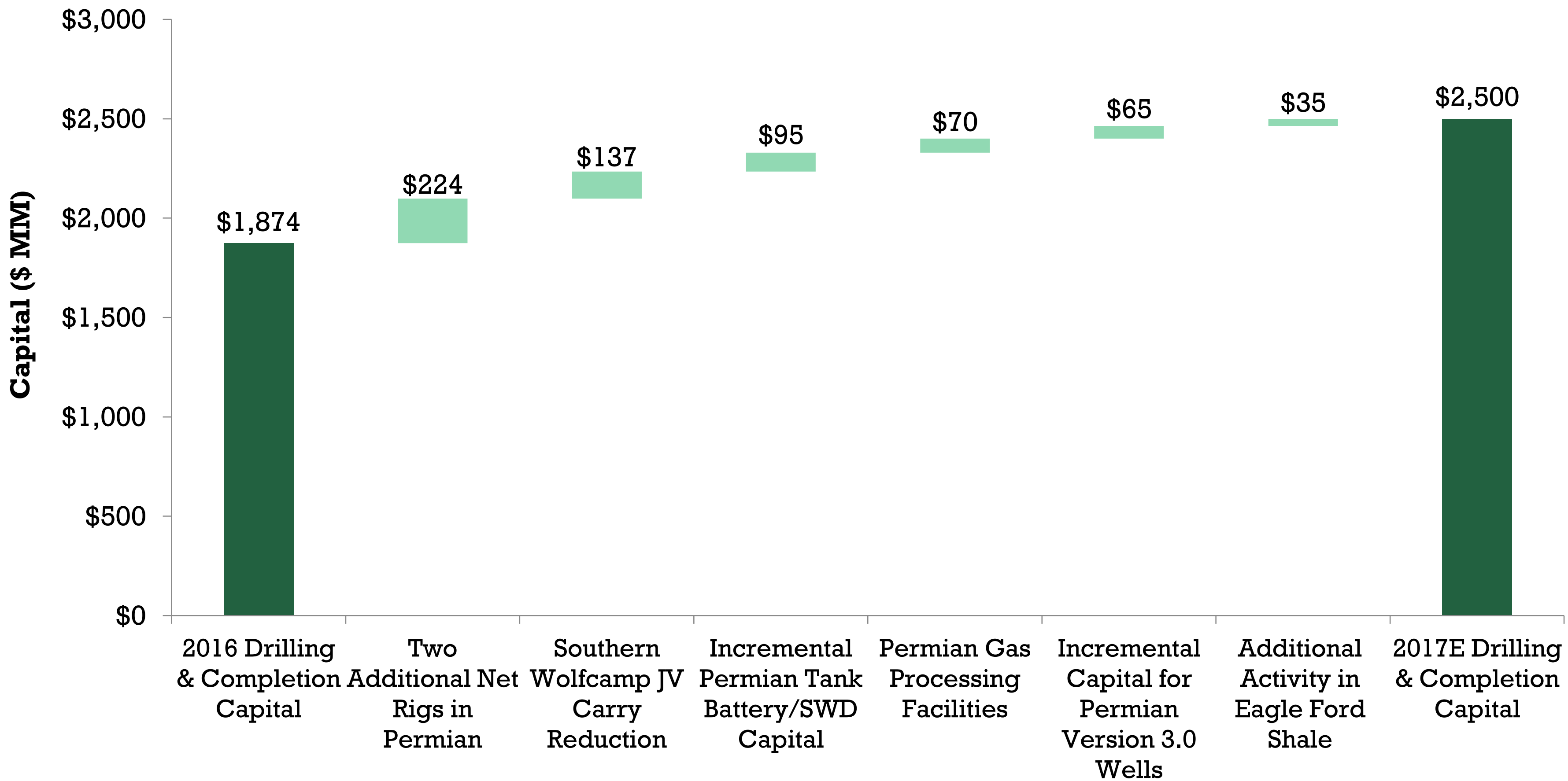
2017 Cash Flow Sensitivity to Forward Commodity Prices ($ MM)



Based on 2017E prices $55/BBL oil and $3/MCF gas

1) Capital spending excludes acquisitions, asset retirement obligations, capitalized interest, G&G G&A and IT system upgrades
2) Remaining JV carry from Sinochem at the end of Q4 2016 totaled $30 MM
3) Includes vertical integration (pressure pumping and well services equipment, water distribution system and sand mine), field facilities and vehicles

DRILLING AND COMPLETION CAPITAL SPENDING RECONCILIATION (2017 VS. 2016)



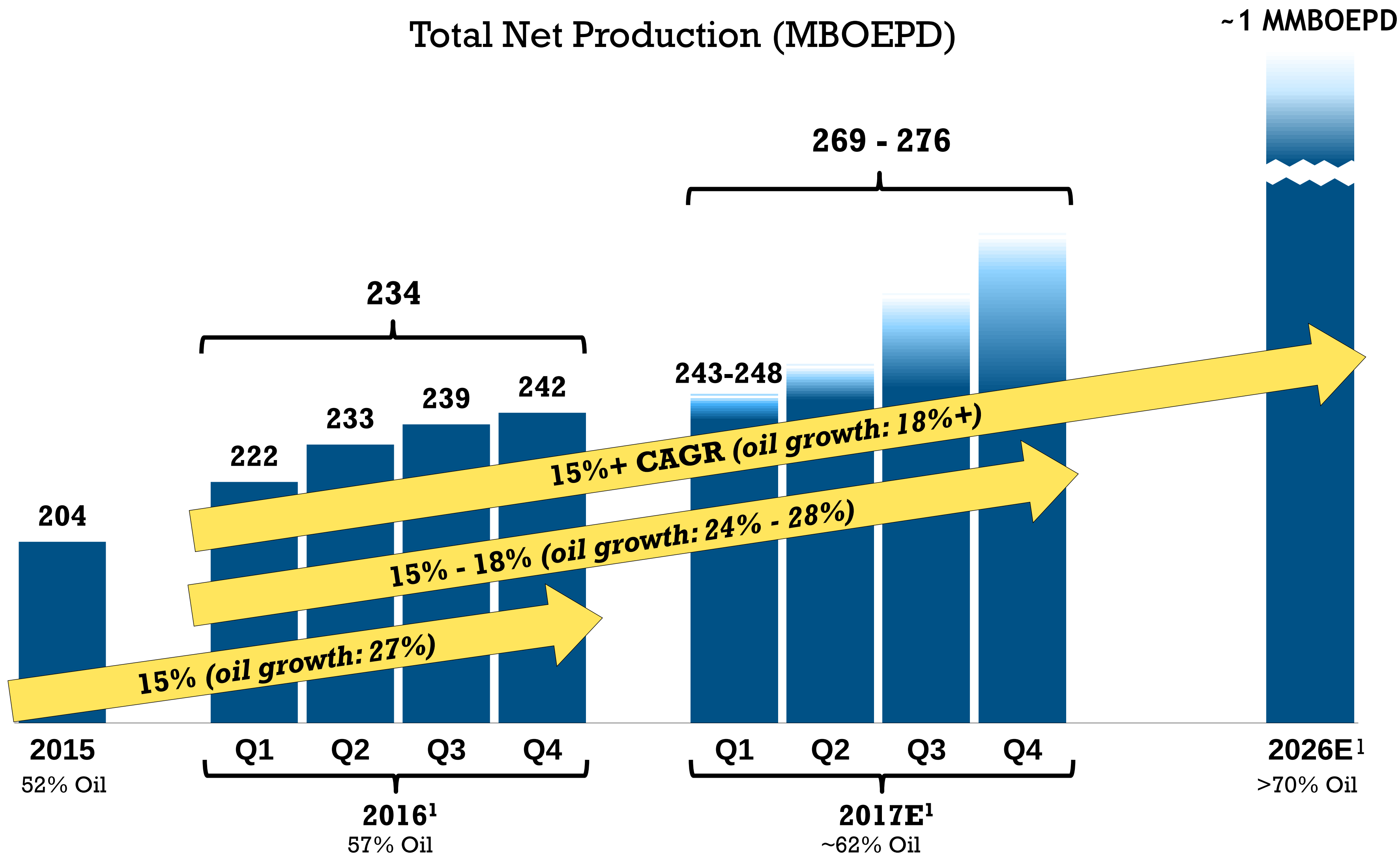
Efficiency gains expected to offset cost inflation

PIONEER'S 10-YEAR VISION

- **Targeting to grow production to 1 MMBOEPD in 2026**
  - Reflects organic compound annual production growth of 15%+ drilling high-return wells
  - Growth driven by world-class Spraberry/Wolfcamp asset
  - Vertical integration and technology enhancements support execution
- **Financial expectations:**
  - Spend within cash flow beginning in 2018; free cash flow positive thereafter
  - Grow cash flow at a compound annual rate of >20%
  - Protect cash flow with an active derivatives program
  - Maintain net debt to cash flow below 1.0x
  - Improve corporate returns

Forecast based on $55/BBL oil price and $3/MCF gas price

PRODUCTION GROWTH FORECAST



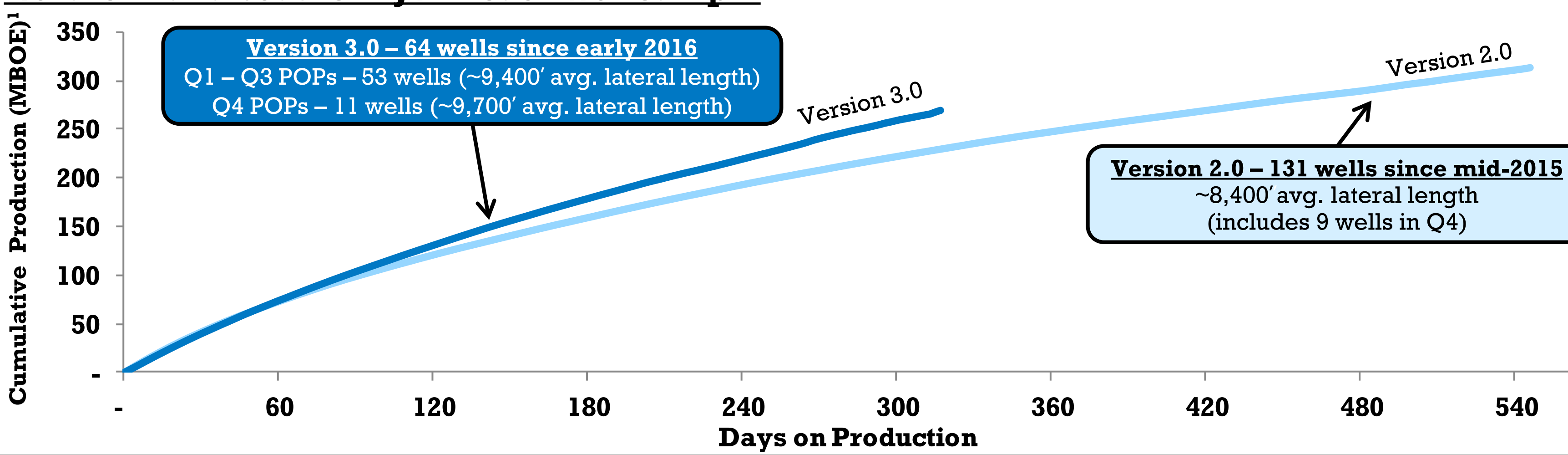
1) Assumes ethane rejection continues in Spraberry/Wolfcamp (~4 MBOEPD in Q4 2016)

VERSION 3.0 COMPLETIONS CONTINUING TO OUTPERFORM VERSION 2.0 COMPLETIONS IN SPRABERRY/WOLFCAMP

Version 3.0 wells pay out incremental capital cost of $0.5 MM to $1.0 MM in less than 1 year

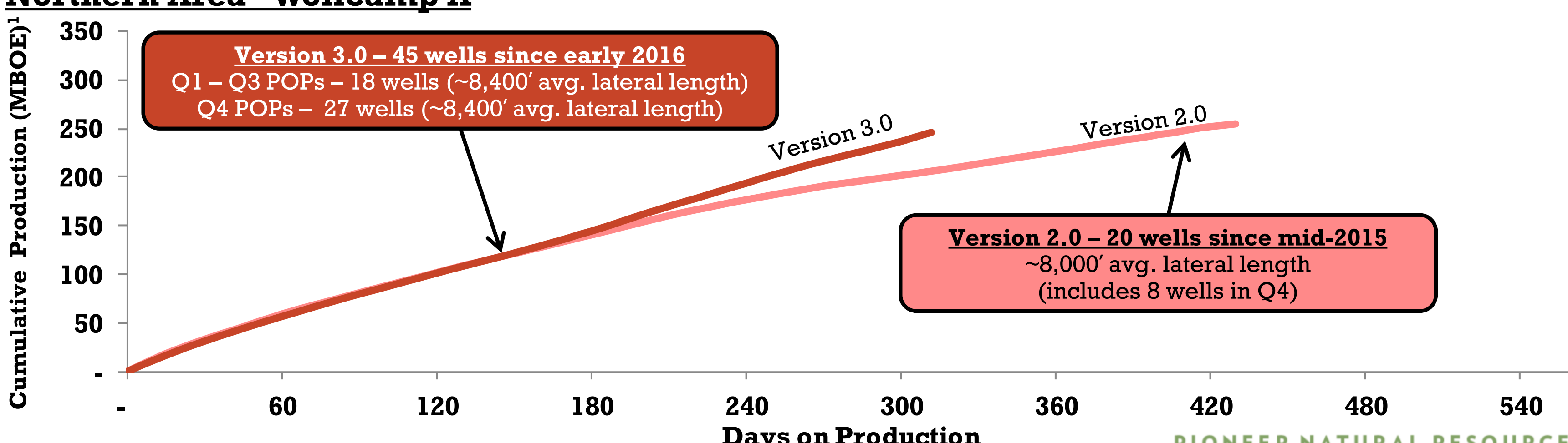
Northern and Southern JV Areas - Wolfcamp B

Updated End January



Northern Area - Wolfcamp A

Updated End January

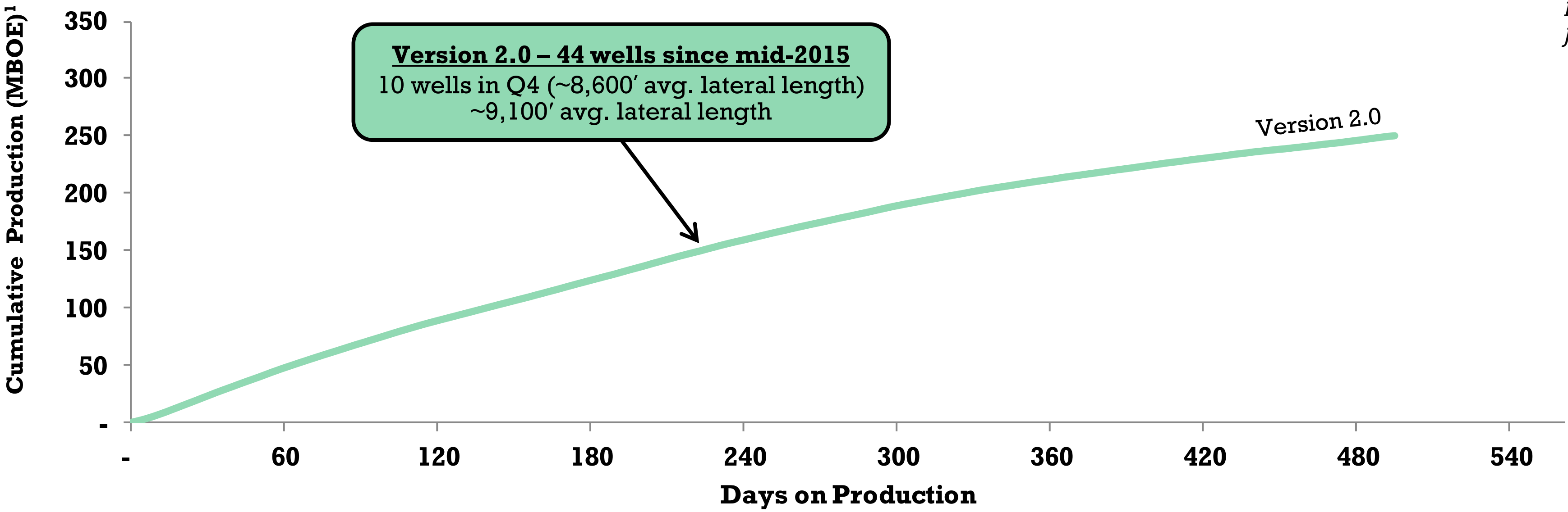


1) Production normalized for shut-ins

LOWER SPRABERRY SHALE WELLS CONTINUE TO DELIVER STRONG PERFORMANCE

Lower Spraberry Shale

Updated End January



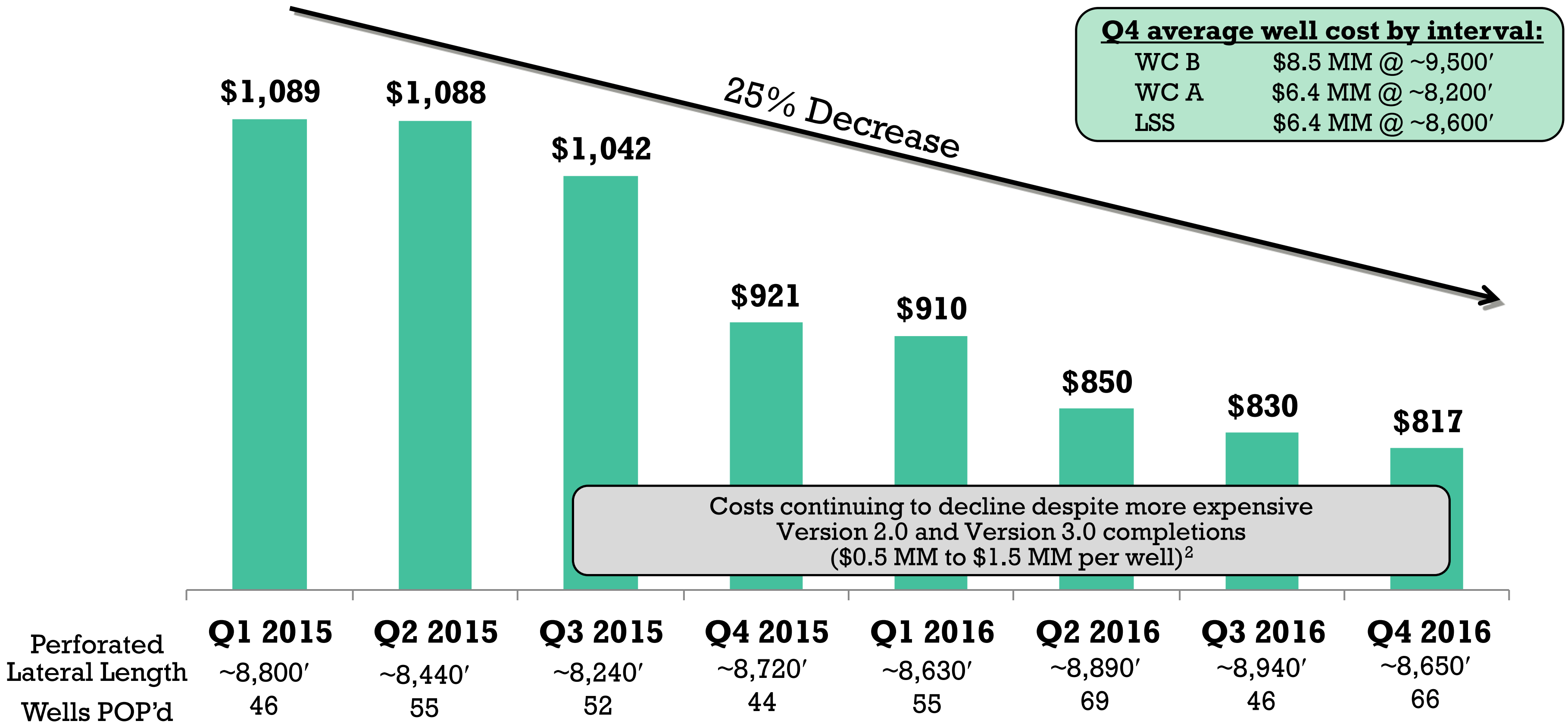
- Lower Spraberry Shale well performance to date indicates Version 2.0 completions will deliver 1 MMBOE EURs
- Plan to commence using Version 3.0 completions in 2017

1) Production normalized for shut-ins

CONTINUING TO REDUCE SPRABERRY/WOLFCAMP DRILLING AND COMPLETION COSTS

Drilling & Completion Cost per Perforated Lateral Foot[1]

(Reflects all wells)



Efficiency gains and cost reduction initiatives more than offsetting higher costs associated with completion optimization program

1) Perforated lateral length ~500′ shorter than drilled length
2) Version 2.0 completions add ~$0.5 MM per well and Version 3.0 completions add $0.5 MM to $1.0 MM per well to the Version 2.0 completion cost

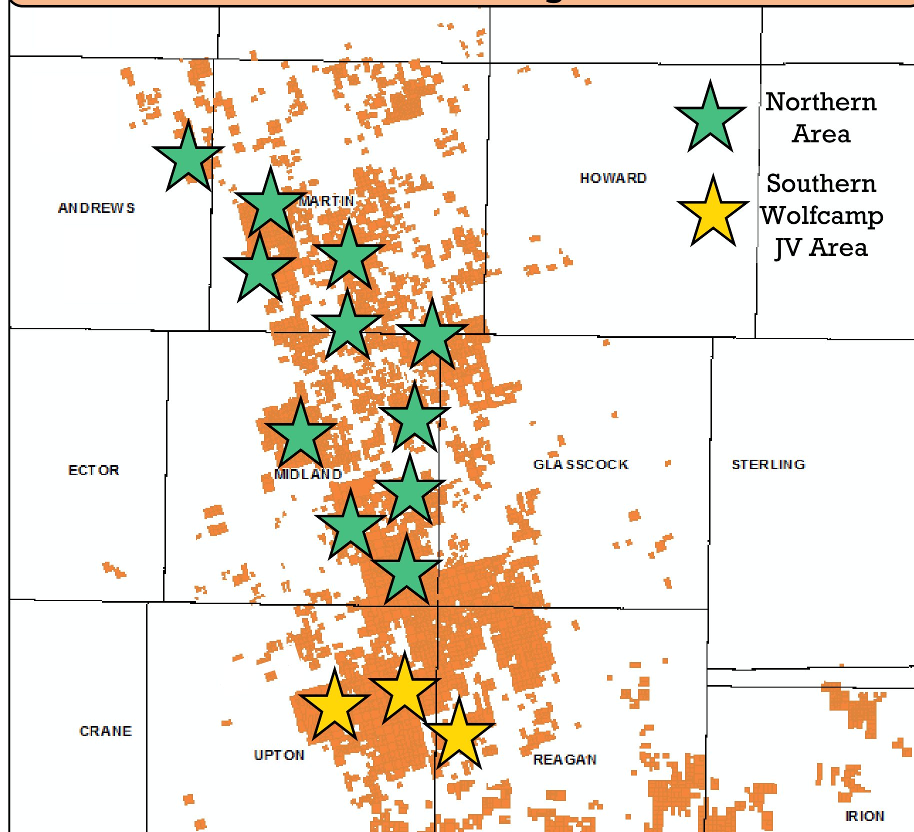
2017 SPRABERRY/WOLFCAMP DRILLING PROGRAM

- **Expect to place ~260 horizontal wells on production during 2017 (244 net POPs)**
- **Horizontal drilling program continuing to deliver strong returns**
  - Version 3.0 completions are the standard design
  - Drilling and completion cost per well:

Interval	Lateral Length	Well Cost ($MM)	Expected EUR (MMBOE)
Wolfcamp B	~10,000′	~$8.5	1.5
Wolfcamp A	~9,500′	~$7.5	1.2
Lower Spraberry Shale	~9,500′	~$7.2	1.0

  - Forecasted horizontal production costs per well:
    - $4/BOE to $5/BOE (includes taxes)
  - Expect to spend $265 MM for tank batteries/SWDs
    - Includes facilities in 5 new areas
  - Forecasting IRRs of 50% to 100% assuming Version 3.0 completions and prices of $55/BBL for oil and $3/MCF for gas (includes 2017 tank battery/SWD costs)

Pioneer's Spraberry/Wolfcamp Acreage Position and 2017 Drilling Areas

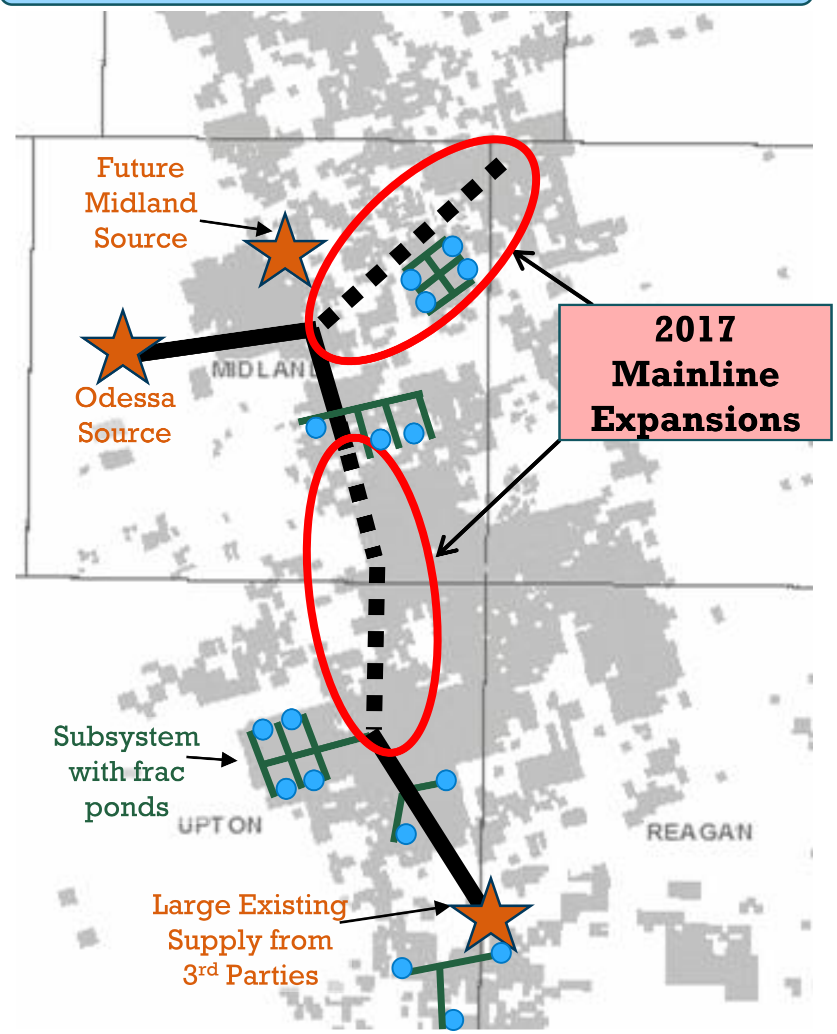


- Plan to place ~260 horizontal wells on production in 2017 (~220 wells in northern area and ~40 gross wells in JV area)
- ~55% Wolfcamp B; ~30% Wolfcamp A; ~15% LSS
- Will also appraise Clearfork, Jo Mill and Wolfcamp D intervals

GAS PROCESSING AND VERTICAL INTEGRATION SUPPORT EXECUTION

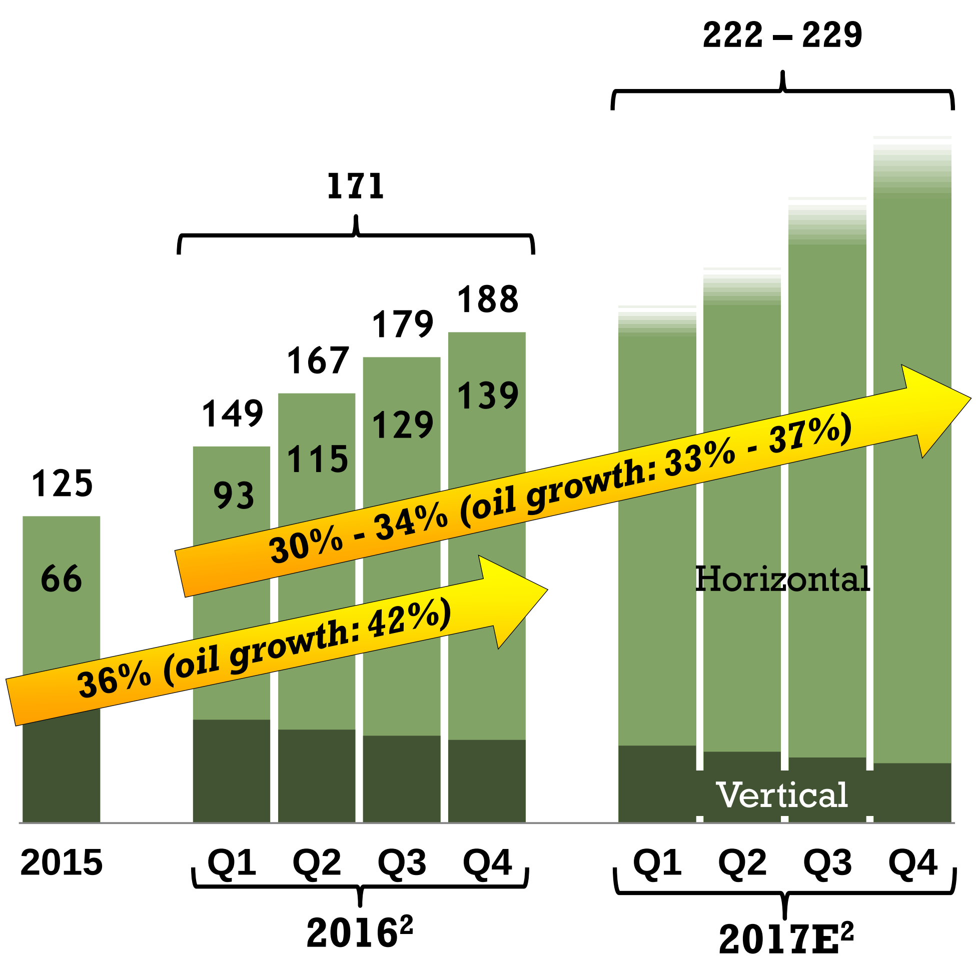
- **Gas Processing**
  - 2017 spending expected to be ~$115 MM; includes ~$70 MM for gathering system compression and new connections and ~$45 MM for capacity additions
- **Water Distribution System**
  - 2017 spending expected to be ~$160 MM; primarily for mainline expansions and additional subsystems/frac ponds; also includes engineering capital for upgrading the Midland wastewater treatment plant
    - Pioneer expects to spend ~$110 MM over the 2017 through 2019 period for the Midland plant upgrade
    - In return, the Company will receive 2 B barrels of low-cost, non-potable water over a 28-year contract period (up to 240 M barrels per day) to support its completion operations
- **Brady Sand Mine**
  - 2017 spending expected to be ~$30 MM to complete optimization of existing facilities to improve yields and reduce overall supply costs
- **Pioneer Pumping Services**
  - 2017 spending expected to be ~$45 MM for fleet upgrades and maintenance

Pioneer's Water Distribution System



SPRABERRY/WOLFCAMP PRODUCTION FORECAST

Spraberry/Wolfcamp Net Production (MBOEPD)[1]



- **Q4 production: 188 MBOEPD (69% oil)**
  - 66 wells placed on production in Q4 2016 as expected (64 wells in northern area and 2 wells in the southern Wolfcamp JV area)
  - 236 wells POP'd in 2016 as expected
    - 195 wells in northern area and 41 wells in southern Wolfcamp JV area (220 net POPs)
- **2017 production outlook**
  - Expect to grow 30% - 34% in 2017
    - Expect to place ~260 wells on production (244 net wells)
- **Q1 production outlook**
  - Expect to POP ~45 wells in Q1
    - Q1 POPs weighted to second half of the quarter compared to 66 wells in Q4 that were evenly distributed over the quarter

1) Includes horizontal and vertical production from Pioneer's northern acreage and the southern Wolfcamp joint venture area (60% Pioneer/40% Sinochem)
2) Assumes ethane rejection continues (~4 MBOEPD in Q4 2016)

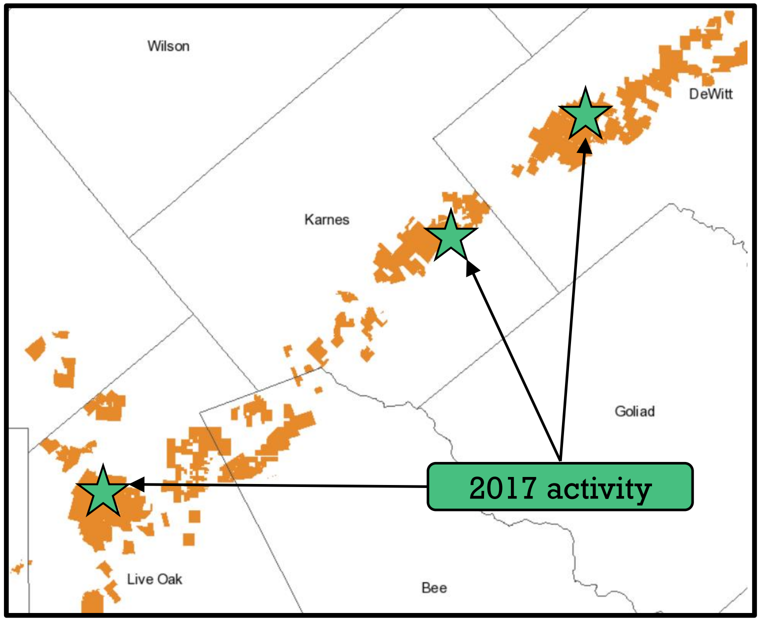
PLANNING LIMITED 2017 EAGLE FORD SHALE DRILLING PROGRAM

- **Plan to complete 20 wells in the Eagle Ford Shale**
  - Includes 9 DUCs that were drilled in late 2015/early 2016 and 11 new wells that will be drilled and completed beginning in Q2
  - Objective of drilling program is to test longer laterals with higher intensity completions
  - D&C cost of new wells: $8.5 MM

Summary of Design Changes:	Previous Design	2017 New Well Testing
Longer Laterals	~5,200′	~7,500′
Tighter Cluster Spacing	50′	30′
Increased Proppant Concentration	1,200 lb/ft	2,000 lb/ft

- **Drilling program moderates production decline**
  - Expecting EURs averaging 1.3 MMBOE with IRRs ranging from 40% to 50% on the new wells[2]
  - Q4 2017 production expected to be ~20% below Q4 2016
  - Year-over-year decline expected to be ~40%

Pioneer's Eagle Ford Shale



Pioneer's Eagle Ford Shale Statistics:
~59,000 net acres in Eagle Ford Shale[1]
100% held-by-production
Q4 production: 27 MBOEPD
(33% condensate, 33% NGLs and 34% gas)

1) Reflects planned divestment of ~10,500 net acres
2) Based on $55/BBL oil price and $3/MCF gas price

Q4 2016 EARNINGS SUMMARY

	$ Millions (After Tax)	$ Per Diluted Share
Net loss attributable to common stockholders	(44)	(0.26)
Noncash mark-to-market (MTM) derivative losses ($222 MM before tax)	142	0.83
Adjusted income excluding noncash MTM derivative losses[1]	98	0.57
Unusual items included in net loss:		
Tax credit for research and experimental expenditures[2]	(13)	(0.08)
Adjusted income excluding noncash MTM derivative losses and unusual items[1]	85	0.49

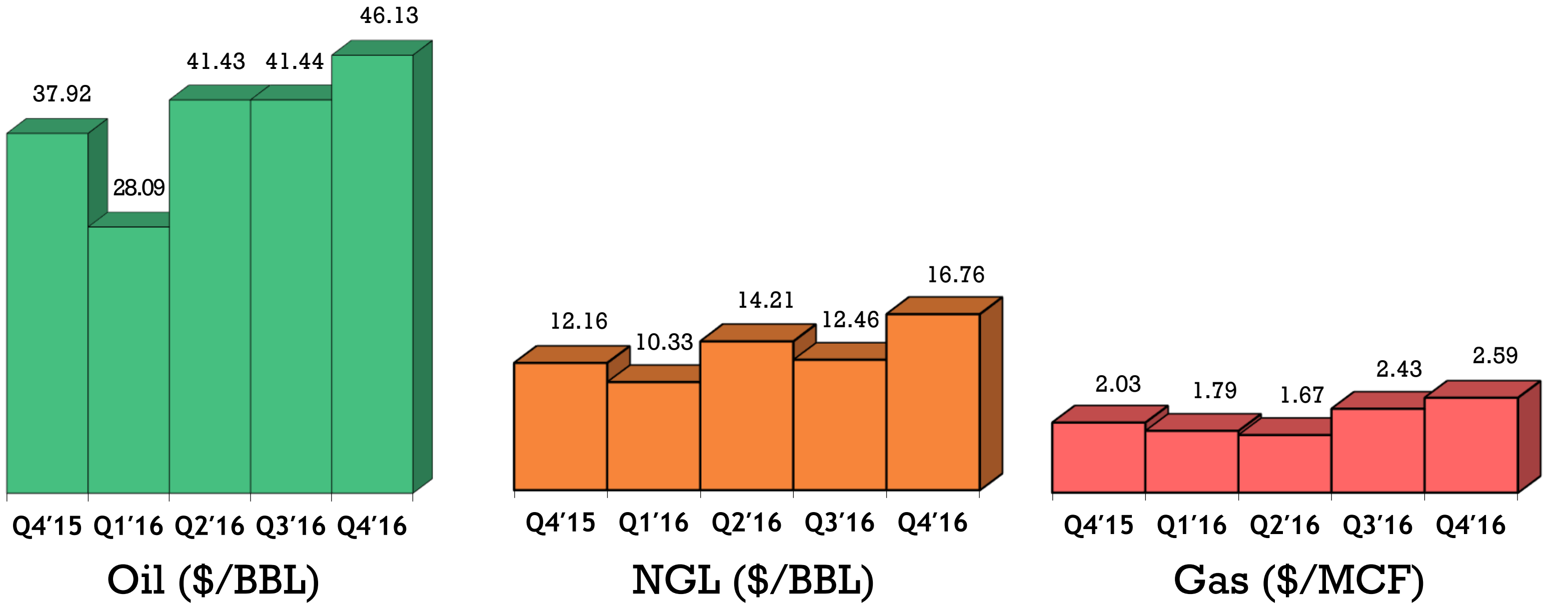
Q4 2016 Guidance vs. Results

	Guidance	Results of Operations Excluding Unusual Items
Daily Production (MBOEPD)	237 – 242	242
Production Costs Including Taxes ($/BOE)	$7.75 - $9.75	$8.20
Exploration & Abandonment ($ MM)	$20 - $30	$23
DD&A ($/BOE)	$17.50 - $19.50	$16.04[3]
G&A ($ MM)	$78 - $83	$89[4]
Interest Expense ($ MM)	$45 - $50	$46
Other Expense ($ MM)	$65 - $75	$65[5]
Accretion of Discount on ARO ($ MM)	$4 - $7	$5
Current Income Tax Provision (Benefit) ($ MM)	<$5	$ -
Effective Tax Rate (%)	35% - 40%	34%

1) Non-GAAP financial measure. See reconciliation in supplemental information slides
2) Income tax benefit associated with tax credits for research and experimental expenditures related to ongoing drilling and completion innovations on horizontal wells
3) DD&A per BOE benefited from Q4 reserve additions associated with (i) drilling activities and (ii) production cost reduction initiatives, which had the effect of adding proved reserves by lengthening the economic lives of the Company's producing wells
4) General and administrative expense includes $8 MM of incremental charges associated with performance-based compensation
5) Includes (i) $33 MM of charges associated with excess firm gathering and transportation commitments, (ii) $8 MM of losses (principally noncash) associated with the portion of vertical integration services provided to nonaffiliated working interest owners, including joint venture partners, in wells operated by the Company and (iii) $7 MM for stacked drilling rig charges

PRICE REALIZATIONS

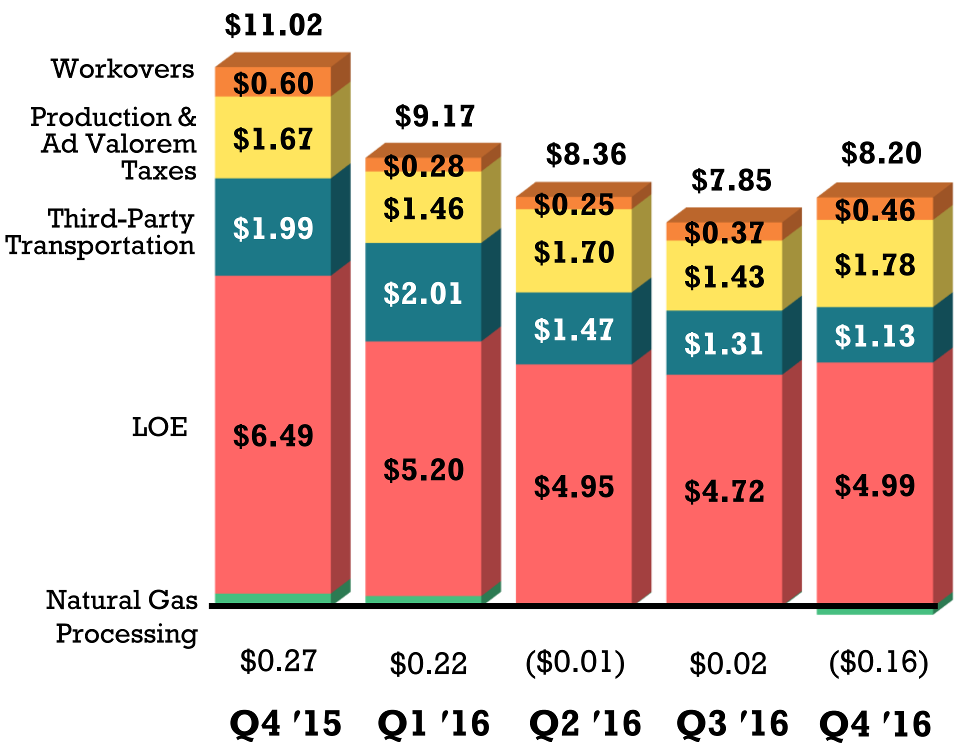
Realized Prices



	Oil Q4'15	Oil Q1'16	Oil Q2'16	Oil Q3'16	Oil Q4'16	NGL Q4'15	NGL Q1'16	NGL Q2'16	NGL Q3'16	NGL Q4'16	Gas Q4'15	Gas Q1'16	Gas Q2'16	Gas Q3'16	Gas Q4'16
NYMEX calendar month average	42.18	33.45	45.59	44.94	49.29	42.18	33.45	45.59	44.94	49.29	2.27	2.09	1.95	2.81	2.98
NYMEX differential	(4.26)	(5.36)	(4.16)	(3.50)	(3.16)	(30.02)	(23.12)	(31.38)	(32.48)	(32.53)	(0.24)	(0.30)	(0.28)	(0.38)	(0.39)
Realized prices	**37.92**	**28.09**	**41.43**	**41.44**	**46.13**	**12.16**	**10.33**	**14.21**	**12.46**	**16.76**	**2.03**	**1.79**	**1.67**	**2.43**	**2.59**
Derivatives not included in price[1]	23.08	17.26	8.97	13.59	10.40	1.17	1.09	0.19	0.40	(0.37)	0.85	0.61	0.68	0.48	0.39
Price including derivatives	**61.00**	**45.35**	**50.40**	**55.03**	**56.53**	**13.33**	**11.42**	**14.40**	**12.86**	**16.39**	**2.88**	**2.40**	**2.35**	**2.91**	**2.98**
Realized NGL prices, excluding derivatives, as a percentage of NYMEX oil calendar month average						**29%**	**31%**	**31%**	**28%**	**34%**					

1) Represents cash settlements recorded in net derivative gains or losses; excludes liquidated derivatives

PRODUCTION COSTS (PER BOE)



- Q4 2016 compared to Q3 2016:
  - LOE increase is primarily due to:
    - Repair costs for mechanical issues at the Fain gas plant in the West Panhandle field
    - Higher repair and maintenance activity associated with the Eagle Ford Shale and Permian vertical wells
  - Lower 3rd party transportation costs as a result of Eagle Ford Shale gathering and treating fees becoming a proportionately smaller component of the Company's total 3rd party transportation costs as Eagle Ford Shale production declines
  - Taxes increased primarily due to commodity price improvements

LIQUIDITY POSITION

- Net debt at the end of Q4 2016 (reflects cash on hand, including liquid investments, of $3.0 B) — $0.2 B
- Unsecured credit facility availability — $1.5 B
- Net debt-to-book capitalization at the end of Q4 — 2%

Maturities and Balances[1]

2017	2018	2020	2021	2022	2026	2028
$485 MM	$450 MM	$450 MM	$500 MM	$600 MM	$500 MM	$250 MM
6.650%	6.875%	7.500%	3.450%	3.950%	4.450%	7.200%

$1.5 B unsecured credit facility (undrawn as of 12/31/16)

- Net debt to 2016 operating cash flow of 0.2x
- Investment grade rated by Moody's, S&P and Fitch

1) Excludes issuance costs and issuance discounts of ~$22 MM; March 2017 maturities to be paid with cash on hand

Q1 2017 GUIDANCE

	Guidance
Daily Production (MBOEPD)	243 – 248
Production Costs ($/BOE)	$7.75 – $9.75
Exploration & Abandonment ($ MM)	$20 – $30
Drilling and Acreage	*$5 - $10*
Personnel and Seismic	*$15 - $20*
DD&A ($/BOE)	$15.50 – $17.50
G&A ($ MM)	$80 – $85
Interest Expense ($ MM)	$45 – $50
Other Expense ($ MM)[1]	$60 – $70
Accretion of Discount on ARO ($ MM)	$4 – $7
Current Income Taxes ($ MM)	<$5
Effective Tax Rate (%)	35% – 40%

1) Other expense includes (i) $35 MM to $40 MM of expected charges associated with excess firm gathering and transportation commitments and (ii) $10 MM to $15 MM of estimated losses (principally noncash) associated with the portion of vertical integration services provided to nonaffiliated working interest owners, including joint venture partners, in wells operated by the Company

SUPPLEMENTAL INFORMATION

PIONEER'S YEAR-END 2016 PROVED RESERVES[1]

- **Added 205 MMBOE from the drillbit, or 232% of full-year production, at a drillbit F&D cost of $9.59 per BOE[2]**
  - Reflects successful Spraberry/Wolfcamp horizontal drilling program
- **Proved developed F&D cost of $9.11 per BOE[3]**
- **Reserve mix**
  - 100% U.S.
  - 52% oil / 19% NGLs / 29% gas
  - 93% PD / 7% PUD
- **Proved Reserves / Production: ~8 years**
- **PD Reserves / Production: ~8 years**

	Year-end 2016 Proved Reserves (MMBOE)
Spraberry/Wolfcamp	556
Raton	85
Eagle Ford	45
Other	40
Total	726

1) Reflects 2016 SEC pricing (12-month NYMEX average) of $42.82/BBL for oil and $2.48/MMBTU for gas as compared to 2015 SEC pricing of $50.11/BBL for oil and $2.59/MMBTU for gas
2) Excludes negative price revisions (58 MMBOE) and reserves added from acquisitions (4 MMBOE)
3) Added 213 MMBOE of proved developed reserves from (i) discoveries and extensions placed on production during 2016, (ii) transfers from proved undeveloped reserves at year-end 2015 and (iii) technical revisions of previous estimates for proved developed reserves during 2016. Revisions of previous estimates excludes price revisions

PRODUCTION BY COMMODITY BY AREA

		Q4 '15	Q1 '16	Q2 '16	Q3 '16	Q4 '16
Spraberry/Wolfcamp	Oil (BOPD)	92,121	102,016	117,388	120,663	130,236
	NGL (BOEPD)	24,701	24,802	27,829	34,631	31,637
	Gas (MCFPD)	120,025	132,029	131,847	144,249	154,836
	Total (BOEPD)	**136,827**	**148,823**	**167,192**	**179,336**	**187,679**
Eagle Ford	Oil (BOPD)	16,504	16,020	12,697	10,567	9,047
	NGL (BOEPD)	11,767	10,544	11,018	10,659	8,830
	Gas (MCFPD)	102,636	90,290	76,056	64,498	55,018
	Total (BOEPD)	**45,377**	**41,612**	**36,391**	**31,976**	**27,047**
Raton	Oil (BOPD)	-	-	-	-	-
	NGL (BOEPD)	-	-	-	-	-
	Gas (MCFPD)	106,780	100,358	98,096	95,200	92,937
	Total (BOEPD)	**17,797**	**16,726**	**16,349**	**15,867**	**15,490**
West Panhandle	Oil (BOPD)	2,909	3,360	3,329	1,745	2,311
	NGL (BOEPD)	4,009	3,734	2,207	3,641	3,566
	Gas (MCFPD)	14,095	13,567	12,812	7,541	5,041
	Total (BOEPD)	**9,267**	**9,354**	**7,671**	**6,642**	**6,717**
South Texas	Oil (BOPD)	1,429	1,404	1,305	1,261	1,238
	NGL (BOEPD)	159	151	169	303	221
	Gas (MCFPD)	22,996	22,366	21,689	20,902	20,607
	Total (BOEPD)	**5,420**	**5,283**	**5,088**	**5,047**	**4,893**
Other	Oil (BOPD)	2	2	4	4	3
	NGL (BOEPD)	4	1	1	1	1
	Gas (MCFPD)	267	41	41	25	26
	Total (BOEPD)	**50**	**10**	**12**	**10**	**7**
Total Continuing Ops	Oil (BOPD)	112,965	122,802	134,723	134,240	142,834
	NGL (BOEPD)	40,639	39,232	41,223	49,235	44,255
	Gas (MCFPD)	366,799	358,651	340,542	332,415	328,465
	Total (BOEPD)	**214,738**	**221,809**	**232,703**	**238,878**	**241,833**

CASH MARGINS BY ASSET

Q4 2016 Cash Margin by Asset

($ per BOE)

	Permian Horizontals	Permian Verticals	Eagle Ford	Other Assets	Total Company
Realized price (ex-hedges)	$ 37.70	$ 35.01	$ 26.31	$ 19.44	$ 33.84
Production costs [1]	(1.96)	(14.01)	(10.88)	(11.41)	(6.42)
Production and ad valorem taxes	(2.31)	(1.53)	(0.34)	(0.94)	(1.78)
Cash margin	**$ 33.43**	**$ 19.47**	**$ 15.09**	**$ 7.09**	**$ 25.64**
% Oil	**71%**	**64%**	**33%**	**13%**	**59%**

1) Includes lease operating expense, third-party transportation, workover expense and net natural gas processing cost

COMPLETION OPTIMIZATION PROGRAM

Designing completions to allow more rock to be contacted closer to the wellbore

Version 1.0
Initial Frac Design
(2013 - 2014)

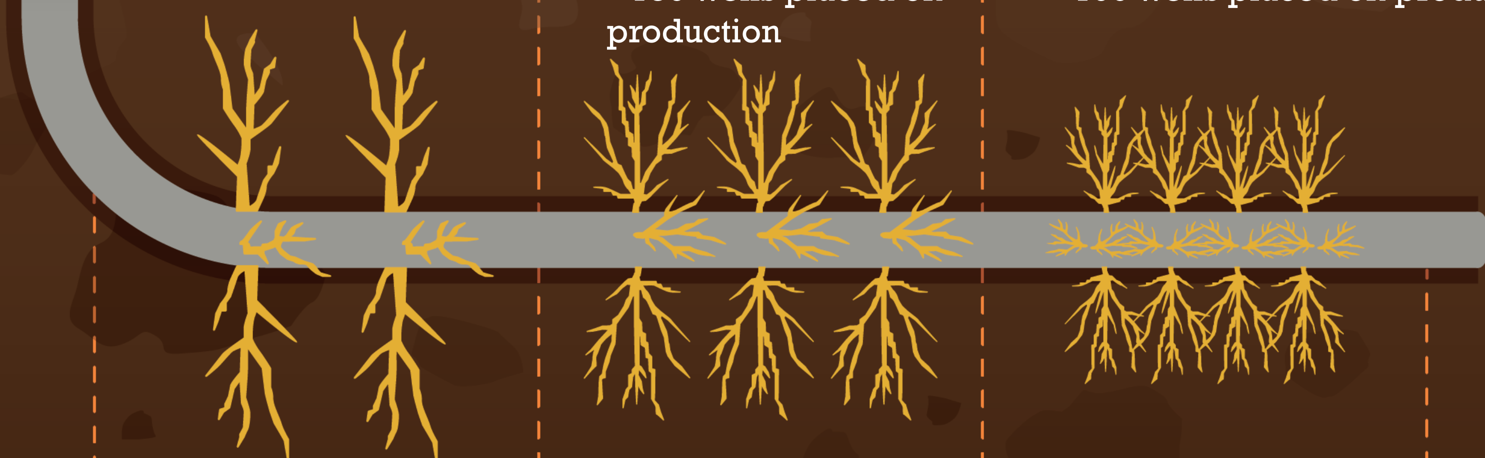
- 1,000 lbs/ft proppant
- 30 bbls/ft fluid
- 60-ft cluster spacing
- 240-ft stage spacing

Version 2.0
Initial Larger Design
(Mid 2015 – 2016)

- 1,400 lbs/ft proppant
- 36 bbls/ft fluid
- 30-ft cluster spacing
- 150-ft stage spacing
- $0.5MM per well vs. initial frac design[1]
- >150 wells placed on production

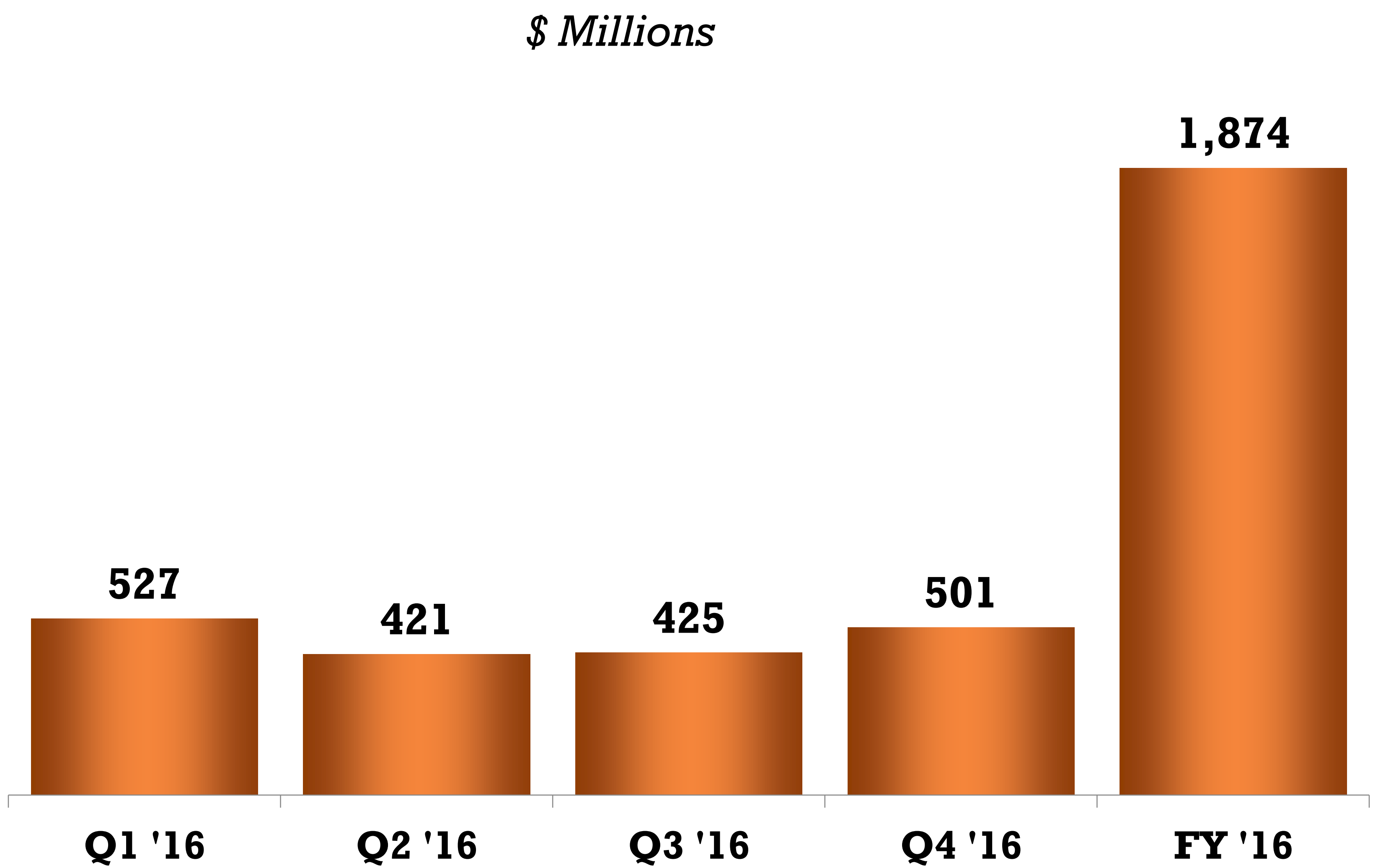
Version 3.0
Current Frac Design
(Q1 2016 – Today)

- Up to 1,700 lbs/ft proppant
- Up to 50 bbls/ft fluid
- Down to 15-ft cluster spacing
- Down to 100-ft stage spacing
- +$0.5MM to $1.0MM per well vs. initial larger frac design[1]
- >100 wells placed on production



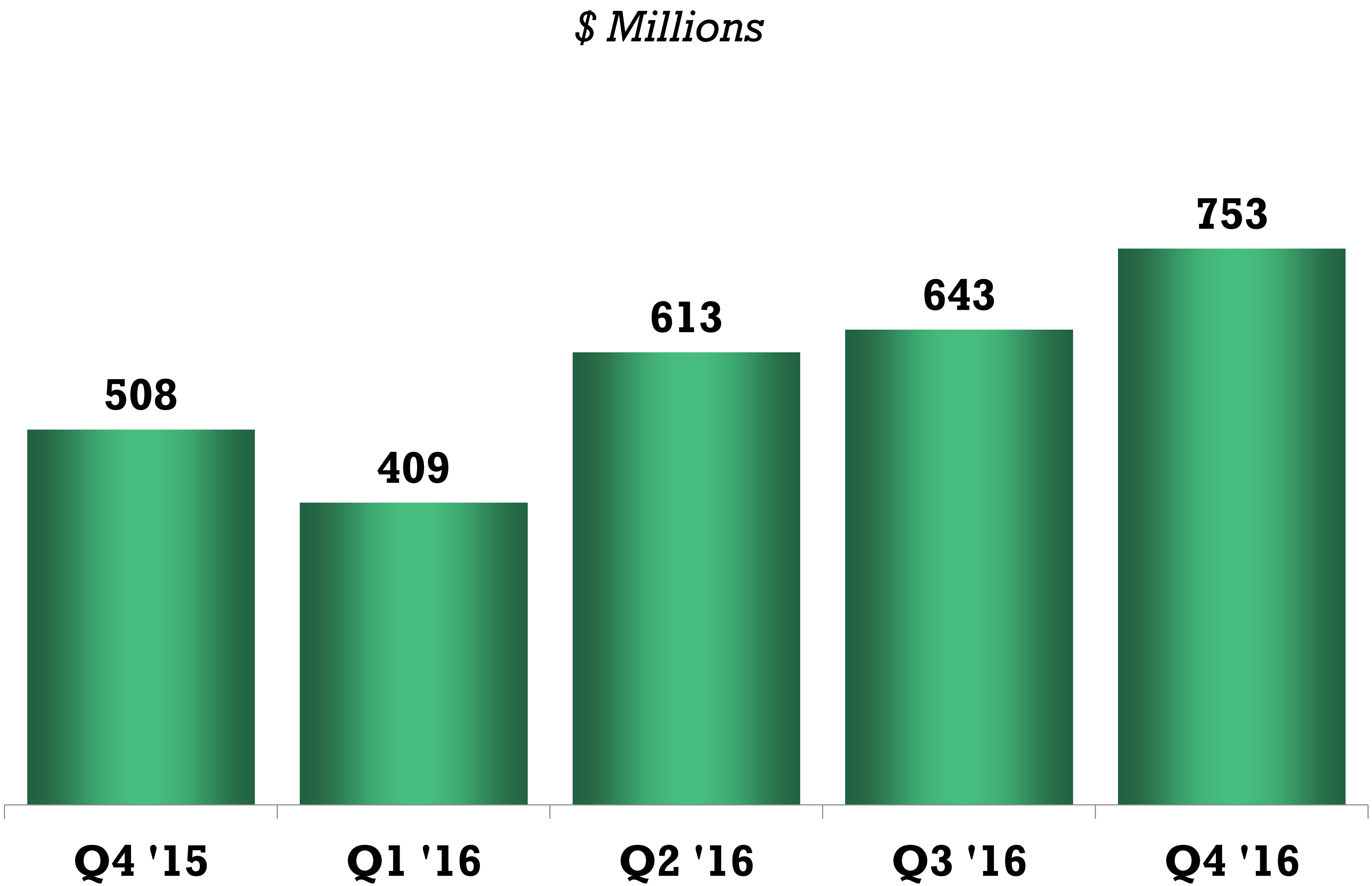
1) Assumes perforated lateral length of 9,000′

2016 DRILLING AND COMPLETIONS CAPITAL[1]



1) Excludes acquisitions, asset retirement obligations, capitalized interest and geological and geophysical G&A expenditures

OIL AND GAS REVENUE



OPEN COMMODITY DERIVATIVE POSITIONS AS OF 2/3/17

Oil	Q1 2017	Q2 2017	Q3 2017	Q4 2017	2018
Collars (BPD)	6,000	6,000	6,000	6,000	-
NYMEX Short Call Price ($/BBL)	$70.40	$70.40	$70.40	$70.40	$ -
NYMEX Put Price ($/BBL)	$50.00	$50.00	$50.00	$50.00	$ -
Three Way Collars (BPD)[1]	119,000	129,000	147,000	155,000	20,000
NYMEX Call Price ($/BBL)	$61.36	$61.19	$62.03	$62.12	$65.14
NYMEX Put Price ($/BBL)	$48.67	$48.46	$49.81	$49.82	$50.00
NYMEX Short Put Price ($/BBL)	$40.65	$40.45	$41.07	$41.02	$40.00
% Total Oil Production	~85%	~85%	~85%	~85%	~10%

Midland-Cushing Fixed Oil Differential	Q1 2017	Q2 2017	Q3 2017	Q4 2017	2018
Market Transaction (BPD)[2]	35,000	35,000	35,000	-	-
Price Differential ($/BBL)	$(1.75)	$(1.75)	$(1.75)	$ -	$ -

Midland-Cushing Basis Swaps	Q1 2017	Q2 2017	Q3 2017	Q4 2017	2018
Basis Swap (BPD)[3]	-	-	-	3,000	740
Price Differential ($/BBL)	$ -	$ -	$ -	$(0.65)	$(0.65)

Oil coverage: ~85% in 2017 and ~10% in 2018

1) When NYMEX price is above call price, Pioneer receives call price. When NYMEX price is between put price and call price, Pioneer receives NYMEX price. When NYMEX price is between the put price and the short put price, Pioneer receives put price. When NYMEX price is below the short put price, Pioneer receives NYMEX price plus the difference between the put price and short put price
2) Not a derivative; contractual agreement that fixes the basis differential between Midland, Texas WTI-posted prices and Cushing, Oklahoma WTI-posted prices; contract expires in September 2017
3) Represents swap contracts that fix the basis differential between Midland, Texas WTI-posted prices and Cushing, Oklahoma WTI-posted prices

OPEN COMMODITY DERIVATIVE POSITIONS AS OF 2/3/17

Ethane	Q1 2017	Q2 2017	Q3 2017	Q4 2017	2018
Collars (BPD)[1]	3,000	3,000	3,000	3,000	-
Mont Belvieu Call Price ($/BBL)	$11.83	$11.83	$11.83	$11.83	$ -
Mont Belvieu Put Price ($/BBL)	$8.68	$8.68	$8.68	$8.68	$ -
Butane					
Swaps (BPD)[2]	-	2,000	2,000	-	-
Mont Belvieu Swap Prices ($/BBL)	$ -	$34.86	$34.86	$ -	$ -
Three Way Collars (BPD)[2]	-	2,000	2,000	-	-
Call Price ($/BBL)	$ -	$36.12	$36.12	$ -	$ -
Put Price ($/BBL)	$ -	$29.25	$29.25	$ -	$ -
Short Put Price ($/BBL)	$ -	$23.40	$23.40	$ -	$ -
% Total NGL Production	~5%	~10%	~10%	~5%	-
% Total Liquids	~70%	~70%	~70%	~70%	~5%

1) Represent collar contracts that reduce the price volatility of ethane forecasted for sale by the Company at Mont Belvieu, Texas-posted prices
2) Represent swap and three way collar contracts that reduce the price volatility of butane forecasted for sale by the Company at Mont Belvieu, Texas posted prices

OPEN COMMODITY DERIVATIVE POSITIONS AS OF 2/3/17

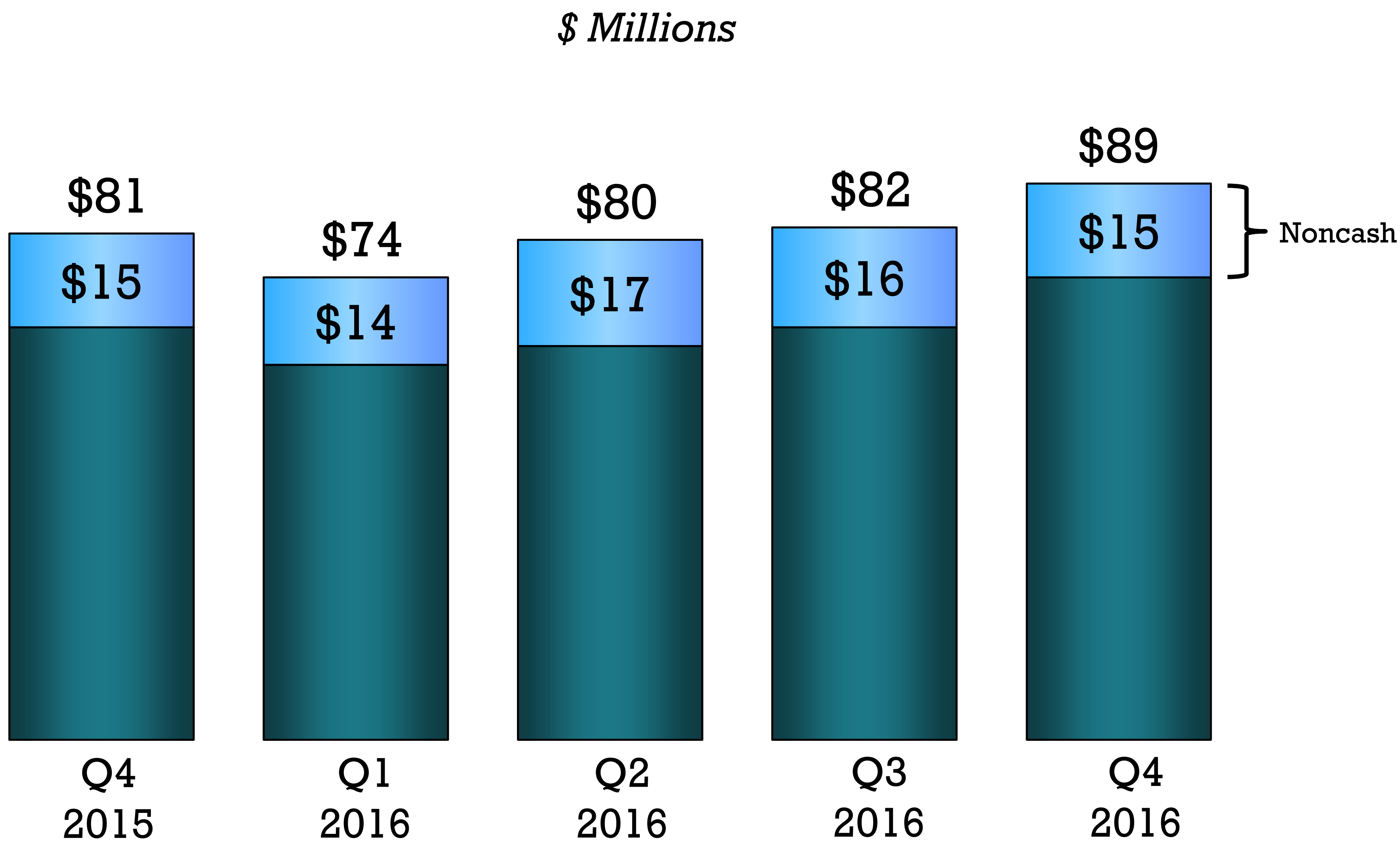
Gas	Q1 2017	Q2 2017	Q3 2017	Q4 2017	2018
Three Way Collars (MMBTUPD)[1,2]	190,000	190,000	190,000	190,000	62,300
NYMEX Call Price ($/MMBTU)	$3.51	$3.51	$3.51	$3.51	$3.56
NYMEX Put Price ($/MMBTU)	$2.93	$2.93	$2.93	$2.93	$2.91
NYMEX Short Put Price ($/MMBTU)	$2.46	$2.46	$2.46	$2.46	$2.37
% Total Gas Production	~60%	~60%	~55%	~55%	~15%

Gas Basis Swaps	Q1 2017	Q2 2017	Q3 2017	Q4 2017	2018
Permian Basin (MMBTUPD)	40,000	-	-	-	-
Price Differential to SoCal ($/MMBTU)	$0.37	$ -	$ -	$ -	$ -
Mid-Continent (MMBTUPD)	45,000	45,000	45,000	45,000	-
Price Differential to NYMEX ($/MMBTU)	$(0.32)	$(0.32)	$(0.32)	$(0.32)	$ -

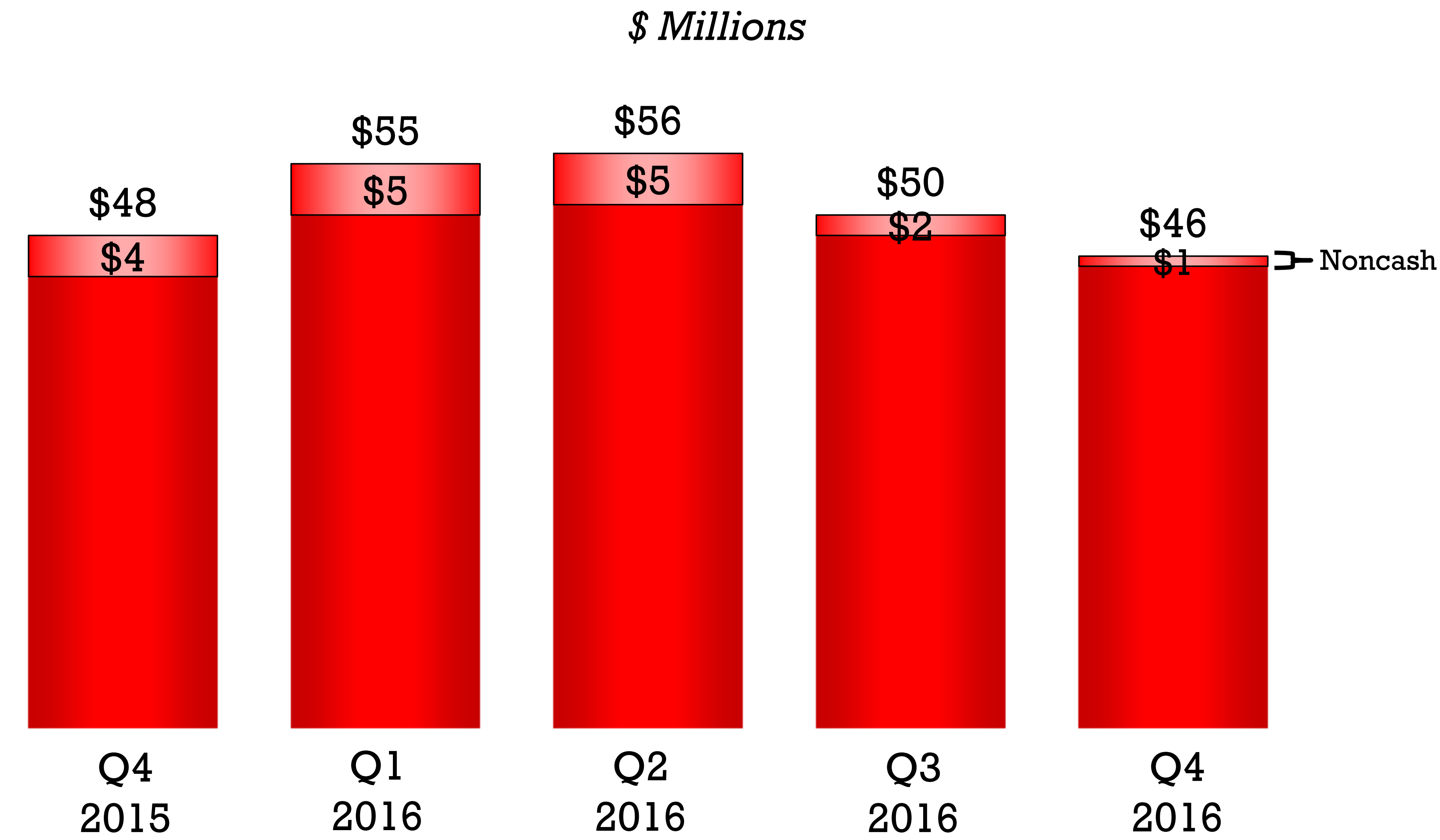
Gas coverage: ~55% for 2017 and ~15% for 2018

1) Represents the NYMEX Henry Hub index price or approximate NYMEX price based on historical differentials to the index price at the time the derivative was entered into
2) When NYMEX price is above call price, Pioneer receives call price. When NYMEX price is between put price and call price, Pioneer receives NYMEX price. When NYMEX price is between the put price and the short put price, Pioneer receives put price. When NYMEX price is below the short put price, Pioneer receives NYMEX price plus the difference between put price and short put price

GENERAL AND ADMINISTRATIVE COSTS



INTEREST COSTS



EXPLORATION & ABANDONMENTS

	($ Millions)
Drilling, Acreage & Other Abandonments	$1
Geological & Geophysical	
Seismic	3
Personnel & Other	19
4th Quarter Total	$23

INCOME TAXES ATTRIBUTABLE TO CONTINUING OPERATIONS

Quarter Ended December 31, 2016	***($ Millions)***
Current tax benefit[1]	$2
Deferred tax benefit[2]	39
Income tax benefit	$41

1) Includes a $2 MM current tax benefit associated with a reduction of the Texas margin tax. The Texas Margin Tax reduction relates to Texas credits for research and experimental expenditures for drilling and completion innovations on horizontal wells
2) Includes the recognition of a $11 MM deferred tax benefit associated with tax credits for research and experimental expenditures

SUPPLEMENTAL NON-GAAP FINANCIAL MEASURES

EBITDAX and discretionary cash flow ("DCF") are disclosed by Pioneer, and reconciled to the generally accepted accounting principle ("GAAP") measures of net loss and net cash provided by operating activities because of their wide acceptance by the investment community as financial indicators of a company's ability to internally fund exploration and development activities and to service or incur debt. The Company also views the non-GAAP measures of EBITDAX and DCF as useful tools for comparisons of the Company's financial indicators with those of peer companies that follow the full cost method of accounting. EBITDAX and DCF should not be considered as alternatives to net loss or net cash provided by operating activities, as defined by GAAP.

	($ Millions)
	Q4 '16
Net loss	($44)
Depletion, depreciation and amortization	357
Impairment of inventory and other property and equipment	2
Exploration and abandonments	23
Accretion of discount on asset retirement obligations	5
Interest expense	46
Income tax benefit	(41)
Loss on disposition of assets, net	1
Derivative related activity	222
Amortization of stock-based compensation	23
Other noncash items	17
EBITDAX	611
Current income tax benefit	2
Cash interest expense	(45)
Discretionary cash flow	568
Cash exploration expense	(22)
Changes in operating assets and liabilities	(9)
Net cash provided by operating activities	$537

SUPPLEMENTAL EARNINGS PER SHARE INFORMATION

The Company uses the two-class method of calculating basic and diluted earnings per share. Under the two-class method of calculating earnings per share, GAAP provides that share- and unit-based awards with guaranteed dividend or distribution participation rights qualify as "participating securities" during their vesting periods. During periods in which the Company realizes net income attributable to common shareholders, the Company's basic net income per share attributable to common stockholders is computed as (i) net income attributable to common stockholders, (ii) less participating basic earnings (iii) divided by weighted average basic shares outstanding and the Company's diluted net income per share attributable to common stockholders is computed as (i) basic net income attributable to common stockholders, (ii) plus the dilutive effect, if any, of participating securities (iii) divided by weighted average diluted shares outstanding. During periods in which the Company realizes a loss attributable to common stockholders, securities or other contracts to issue common stock are dilutive to loss per share; therefore, conversion into common stock is assumed not to occur.

The following table is a reconciliation of the Company's net loss attributable to common stockholders to basic and diluted net loss attributable to common stockholders for the three months ended December 31, 2016:

	($ Millions) **Q4 '16**
Net loss attributable to common stockholders	($44)
Participating basic earnings	—
Basic and diluted net loss attributable to common stockholders	($44)

	(Shares in Millions) **Q4 '16**
Weighted average common shares outstanding:	
Basic	170
Dilutive common stock options	—
Contingently issuable performance unit shares	—
Diluted	170

SUPPLEMENTAL NON-GAAP FINANCIAL MEASURES

Adjusted income excluding noncash MTM derivative losses and adjusted income excluding noncash MTM derivative losses and unusual items, as presented in the Financial and Operating Highlights slide and in the Q4 2016 Earnings Summary slide, are presented and reconciled to Pioneer's net loss attributable to common stockholders (determined in accordance with GAAP) because Pioneer believes that these non-GAAP financial measures reflect an additional way of viewing aspects of Pioneer's business that, when viewed together with its financial results computed in accordance with GAAP, provides a more complete understanding of factors and trends affecting its historical financial performance and future operating results, greater transparency of underlying trends and greater comparability of results across periods. In addition, management believes that these non-GAAP measures may enhance investors' ability to assess Pioneer's historical and future financial performance. These non-GAAP financial measures are not intended to be substitutes for the comparable GAAP measures and should be read only in conjunction with Pioneer's consolidated financial statements prepared in accordance with GAAP. Noncash MTM derivative gains and losses and unusual items will recur in future periods; however, the amount and frequency can vary significantly from period to period. The table below reconciles Pioneer's net loss attributable to common stockholders for the three months ended December 31, 2016, as determined in accordance with GAAP, to adjusted income excluding noncash MTM derivative losses and adjusted income excluding noncash MTM derivative losses and unusual items for that quarter.

	$ Millions (After Tax)	**$ Per Diluted Share**
Net loss attributable to common stockholders	(44)	(0.26)
Noncash MTM derivative losses ($222 MM before tax)	142	0.83
Adjusted income excluding noncash MTM derivative losses	98	0.57
Unusual items included in net loss:		
Tax credit for research and experimental expenditures[1]	(13)	(0.08)
Adjusted income excluding noncash MTM derivative losses and unusual items	85	0.49

1) Income tax benefit associated with tax credits for research and experimental expenditures related to ongoing drilling and completion innovations on horizontal wells

RESERVES AUDIT, F&D COSTS AND RESERVE REPLACEMENT

An audit of proved reserves follows the general principles set forth in the standards pertaining to the estimating and auditing of oil and gas reserve information promulgated by the Society of Petroleum Engineers ("SPE"). A reserve audit as defined by the SPE is not the same as a financial audit. Please see the Company's Annual Report on Form 10-K for a general description of the concepts included in the SPE's definition of a reserve audit.

"Drillbit finding and development cost per BOE," or "drillbit F&D cost per BOE," means the summation of exploration and development costs incurred divided by the summation of annual proved reserves, on a BOE basis, attributable to discoveries and extensions (excludes purchases of minerals-in-place) and revisions of previous estimates. Revisions of previous estimates exclude price revisions. Consistent with industry practice, future capital costs to develop proved undeveloped reserves are not included in costs incurred.

"Drillbit reserve replacement" is the summation of annual proved reserve additions, on a BOE basis, attributable to discoveries and extensions (excludes purchases of minerals-in-place) and revisions of previous estimates divided by annual production of oil, NGLs and gas, on a BOE basis. Revisions of previous estimates exclude price revisions.

"Proved developed finding and development cost per BOE," or "proved developed F&D cost per BOE," means the summation of exploration and development costs incurred (excluding asset retirements obligations) divided by the summation of annual proved reserves, on a BOE basis, attributable to proved developed reserve additions, including (i) discoveries and extensions placed on production during 2016, (ii) transfers from proved undeveloped reserves at year-end 2015 and (iii) technical revisions of previous estimates for proved developed reserves during 2016. Revisions of previous estimates exclude price revisions.

CERTAIN RESERVE INFORMATION

Cautionary Note to U.S. Investors --The SEC prohibits oil and gas companies, in their filings with the SEC, from disclosing estimates of oil or gas resources other than "reserves," as that term is defined by the SEC. In this presentation, Pioneer includes estimates of quantities of oil and gas using certain terms, such as "resource potential," "net recoverable resource potential," "estimated ultimate recovery," "EUR," "oil in place" or other descriptions of volumes of reserves, which terms include quantities of oil and gas that may not meet the SEC's definitions of proved, probable and possible reserves, and which the SEC's guidelines strictly prohibit Pioneer from including in filings with the SEC. These estimates are by their nature more speculative than estimates of proved reserves and accordingly are subject to substantially greater risk of being recovered by Pioneer. U.S. investors are urged to consider closely the disclosures in the Company's periodic filings with the SEC. Such filings are available from the Company at 5205 N. O'Connor Blvd., Suite 200, Irving, Texas 75039, Attention: Investor Relations, and the Company's website at www.pxd.com. These filings also can be obtained from the SEC by calling 1-800-SEC-0330.