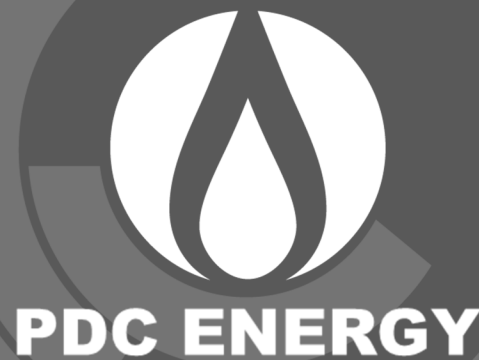


BANK OF AMERICA MERRILL LYNCH GLOBAL ENERGY CONFERENCE

November 16, 2016



Forward Looking Statements



This presentation contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 ("Securities Act") and Section 21E of the Securities Exchange Act of 1934 ("Exchange Act") regarding our business, financial condition, results of operations and prospects. All statements other than statements of historical facts included in and incorporated by reference into this report are "forward-looking statements" within the meaning of the safe harbor provisions of the United States ("U.S.") Private Securities Litigation Reform Act of 1995. Words such as expects, anticipates, intends, plans, believes, seeks, estimates and similar expressions or variations of such words are intended to identify forward-looking statements herein. These statements relate to, among other things: the closing of pending transactions and the effects of such transactions, including the fact that a Delaware Basin acquisition is subject to continuing diligence between the parties and accordingly, may not occur within the expected timeframe or at all; estimated future production (including the components of such production), sales, expenses, cash flows, liquidity and balance sheet attributes; estimated crude oil, natural gas and natural gas liquids ("NGLs") reserves; the impact of prolonged depressed commodity prices, including potentially reduced production and associated cash flow; anticipated capital projects, expenditures and opportunities; expected capital budget allocations; our operational flexibility and ability to revise our development plan, either upward or downward; availability of sufficient funding and liquidity for our capital program and sources of that funding; expected positive net settlements on derivatives for the remainder of 2016; that we expect quarter-over-quarter production growth; future exploration, drilling and development activities, including non-operated activity, the number of drilling rigs we expect to run and lateral lengths of wells, including the number of rigs we expect to run in 2017 in the Delaware Basin; expected 2016 production and cash flow ranges and timing of turn-in-lines; our evaluation method of our customers' and derivative counterparties' credit risk; effectiveness of our derivative program in providing a degree of price stability; potential for future impairments; expected sustained relief of gathering system pressure; compliance with debt covenants; impact of litigation on our results of operations and financial position; that we do not expect to pay dividends in the foreseeable future; and our future strategies, plans and objectives. .

The above statements are not the exclusive means of identifying forward-looking statements herein. Although forward-looking statements made in this presentation reflect PDC's good faith judgment, such statements can only be based on facts and factors currently known to PDC. Forward-looking statements are always subject to risks and uncertainties, and become subject to greater levels of risk and uncertainty as they address matters further into the future. Throughout this presentation, the Company uses the terms "outlook," "projection" or similar terms or expressions, to indicate that it has "modeled" certain future scenarios. PDC typically uses these terms to indicate its current thoughts on possible outcomes relating to its business or the industry in periods beyond the current fiscal year. In addition to being subject to additional levels of uncertainty generally, forward-looking statements regarding such prospective matters do not necessarily reflect the outcomes the Company views as the most likely to occur, but instead are shown to illustrate aspects of its business in the context of a variety of scenarios it believes to be plausible.

PDC urges you to carefully review and consider the cautionary statements and disclosures, specifically those under Item 1A, *Risk Factors*, made in the Company's Annual Report on Form 10-K for the year ended December 31, 2015 and PDC's other filings with the U.S. Securities and Exchange Commission ("SEC"), which are incorporated by this reference as though fully set forth herein, for further information on risks and uncertainties that could affect the Company's business, financial condition, results of operations and cash flows. The Company cautions you not to place undue reliance on forward-looking statements, which speak only as of the date hereof. **PDC undertakes no obligation to update any forward-looking statements in order to reflect any event or circumstance occurring after the date of this presentation or currently unknown facts or conditions or the occurrence of unanticipated events. All forward looking statements are qualified in their entirety by this cautionary statement.**



PDC Energy – Pro Forma Company Overview

Delaware Acquisition Expected to Close in December 2016

2Q16 / Post Closing

\$3.5 / \$5.4

Est. Enterprise Value (Billions)

~1.1x / ~2.2x

YE16e Debt/EBITDAX⁽¹⁾

>64 / >74

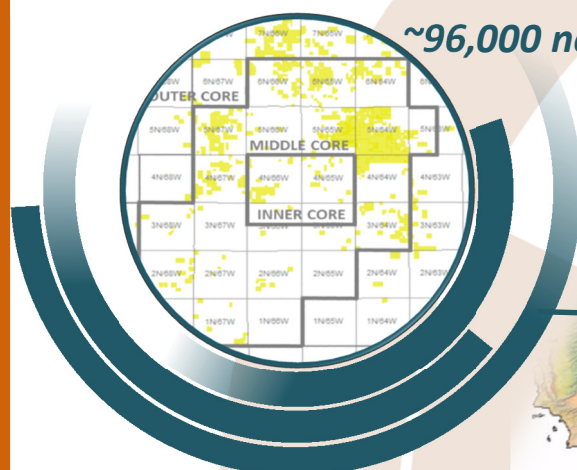
Est. December Exit Rate
Net Daily Production (MBoe/d)

2,150 / 2,860

Appx. Currently Identified
Potential Hz Locations

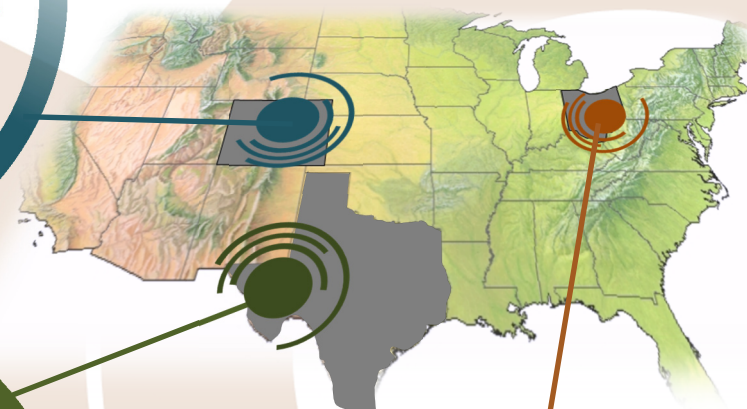
Core Wattenberg

~96,000 net acres



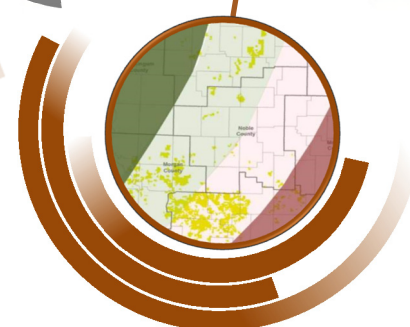
Core Delaware

~57,000 net acres



Utica Shale

~65,000 net acres



11/16/2016

(1) EBITDAX is adj. EBITDA plus exploration expense, excludes gain/loss sale on assets.
YE16e Post Closing Debt/EBITDAX of 2.2x includes September 2016 equity issuance and both senior and convertible note offerings.



PDC Energy – 2016 Results and Outlook

These Do Not Include Delaware Basin Acquisition Expected to Close in December 2016

3Q16 Results

65,263

Production (Boe/d)

39%

Year-over-Year Production Increase
(MMBoe)

40

3Q16 Gross Operated TILs⁽¹⁾

\$2.33

~ Loe per Boe

Full-Year 2016 Highlights

- Production range of 21 – 22 MMBoe
 - 40% increase over 2015 at mid-point
 - Expect to meet or exceed top-end of range
- Capital Expenditures of \$400 - \$420 million
 - Range now includes ~\$15 - \$20 million for Delaware Basin
- Anticipate 4Q16 to be ~\$100 million cash flow positive
- ~140 spuds and ~145 TILs⁽²⁾
- 2016e product mix:
 - 40-42% Oil; 38-40% Natural Gas; 20-22% NGLs

2016e Wattenberg Drilling Program⁽³⁾

All numbers approximate	SRL	MRL	XRL
Lateral Length	4,200'	6,900'	9,500'
Drilling Days (spud-to-spud)	6-8	10-12	13-15
Portion of Spuds	35%	28%	37%
Portion of TILs	51%	36%	13%
Completed Well Cost (millions)	\$2.5	\$3.5	\$4.5

11/16/2016

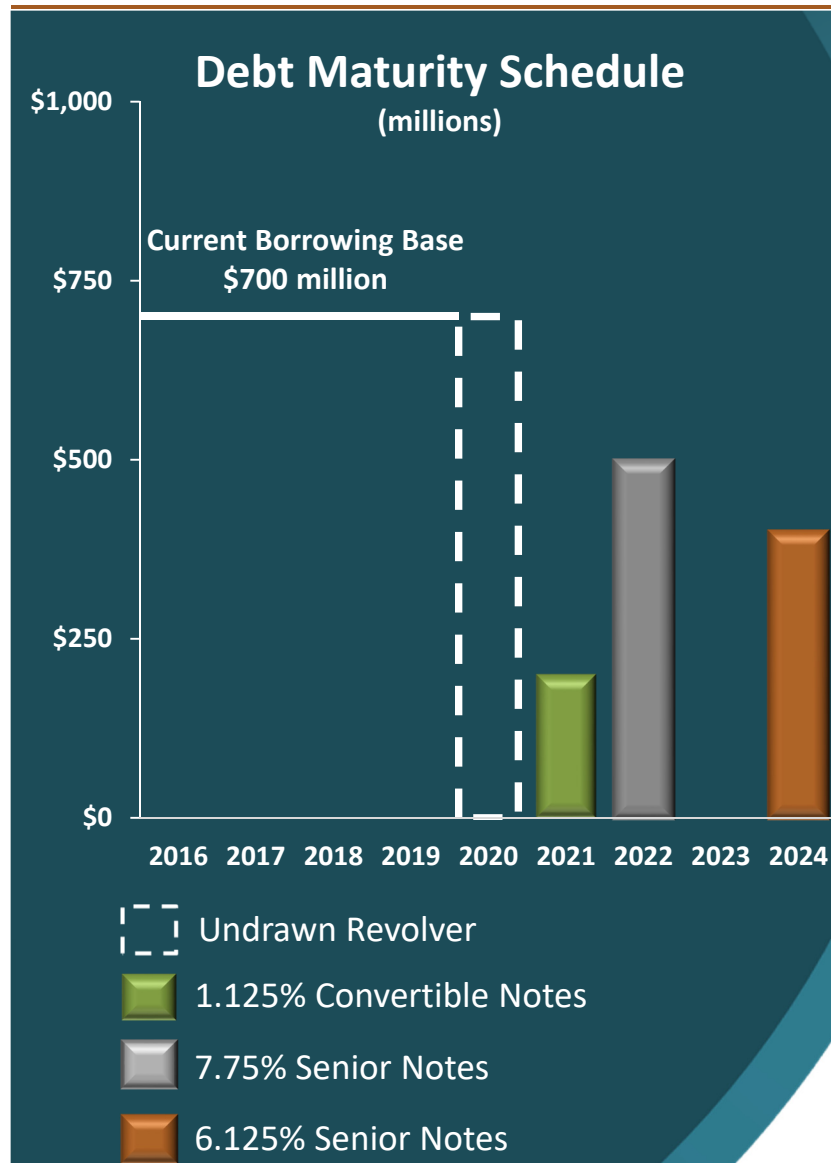
(1) Turn-in-line; (2) Includes 2H16 Delaware Basin spuds and TILs;

(3) SRL = Standard-Reach Lateral; MRL = Mid-Reach Lateral; XRL = Extended-Reach Lateral; costs inclusive of plug-n-perf completions



PDC Energy – Debt and Liquidity Overview

As of 9/30/16



- Issued ~9.1 million shares of equity for net proceeds of ~\$560 million

Debt Maturities

- \$700 million credit facility (May 2020)⁽¹⁾
- \$200 million 1.125% convertible notes (September 2021)
- \$500 million 7.75% senior notes (October 2022)
- \$400 million 6.125% senior notes (September 2024)

Leverage and Liquidity

- YE16e Debt/ EBITDAX⁽²⁾ of ~2.2x
- ~\$1.2 billion cash balance
 - ~\$350 million pro forma acquisition closing
- ~\$1.6 billion liquidity
 - ~\$1.0 billion pro forma acquisition closing

11/16/2016

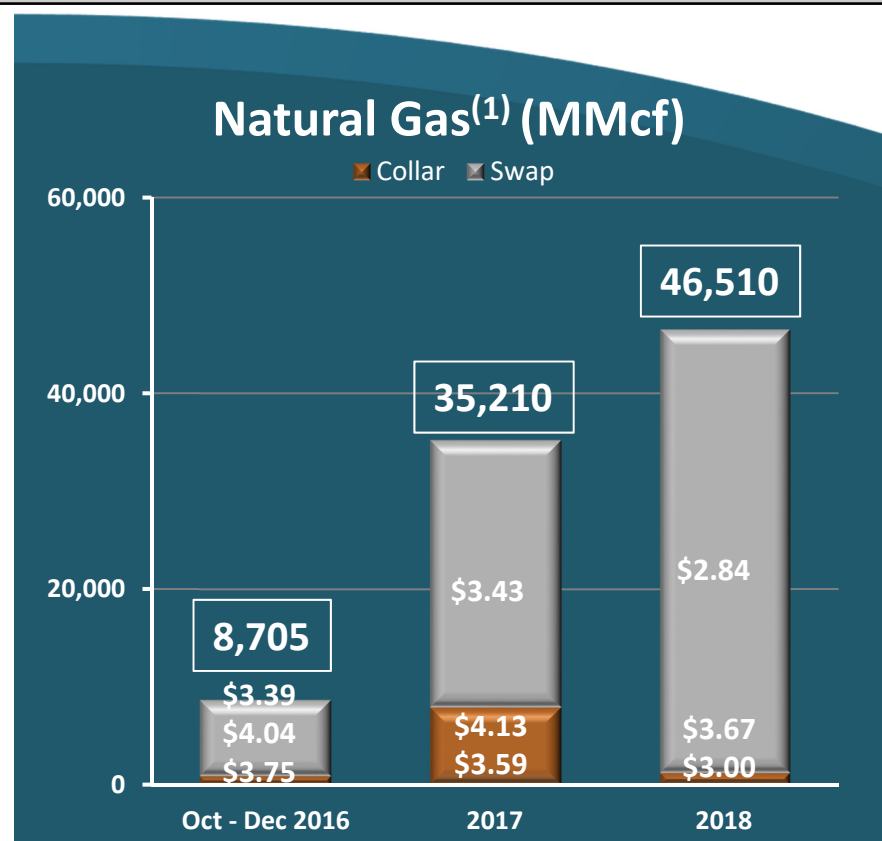
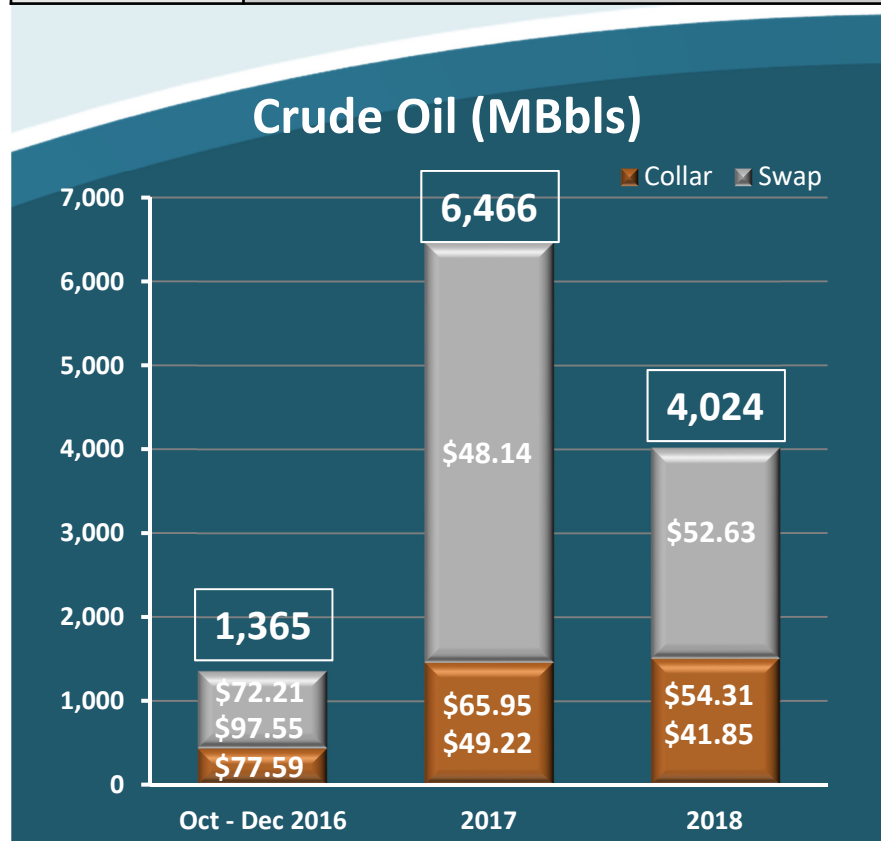
(1) Revolving credit facility commitments currently at \$450 million, increasing to \$700 million at expected closing of the acquisition in December 2016.
(2) EBITDAX is adjusted EBITDA plus exploration expense, includes gain/loss on sale of assets & pre-tax provision for uncollectible notes receivable of \$44.0 million.

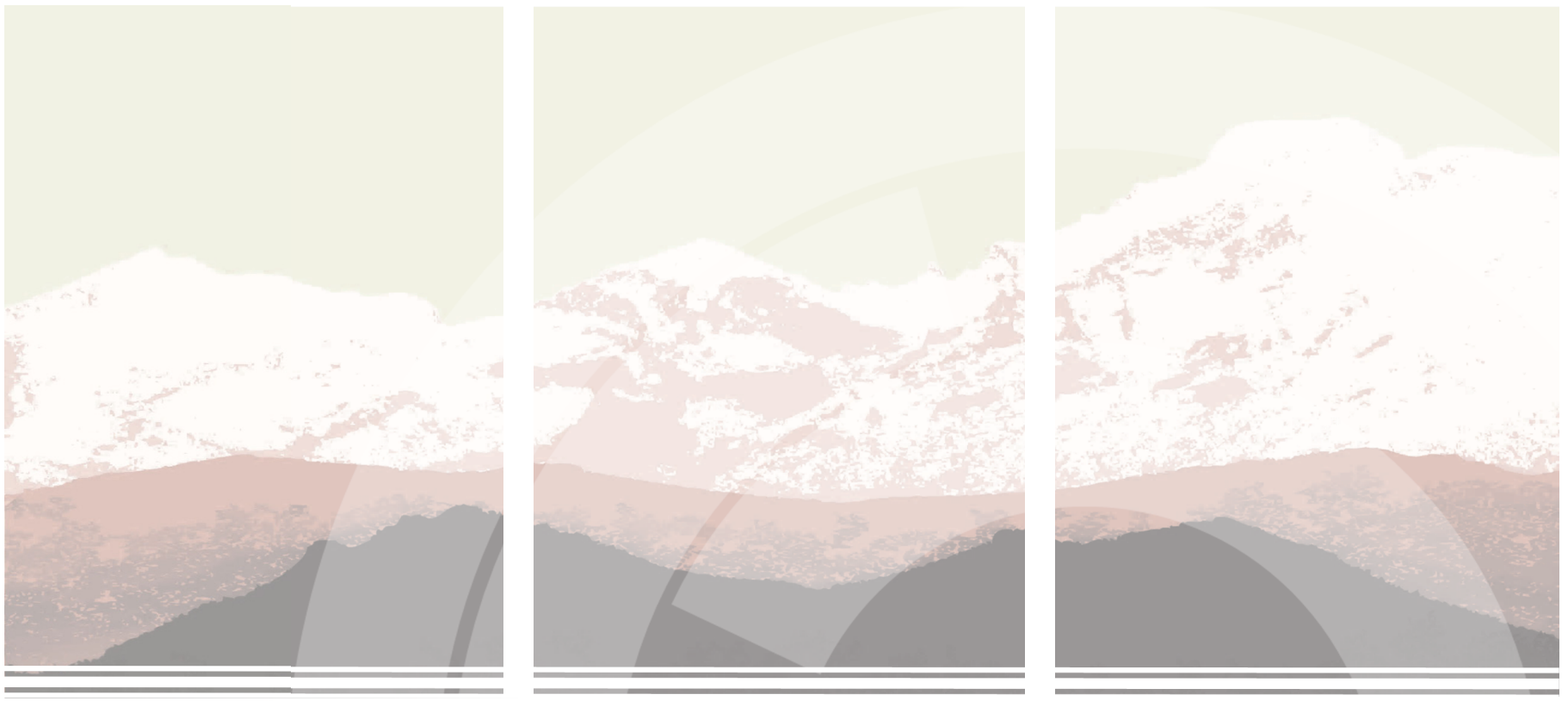


PDC Energy – Hedge Position Summary

Hedges in place as of September 30, 2016 plus hedges entered prior to October 31, 2016

Oct – Dec 2016	~1.4 MMBbls of crude oil volumes at weighted average floor price of \$73.92/Bbl
	~8.7 Bcf of natural gas volumes at weighted average floor price of \$3.42/Mcf
2017	~6.5 MMBbls of crude oil at weighted average floor price of \$48.39/Bbl
	~35.2 Bcf of natural gas at weighted average floor price of \$3.47/Mcf





ACQUISITION OVERVIEW

Transformative Core Delaware Basin Acquisition



Expected to Close in December 2016

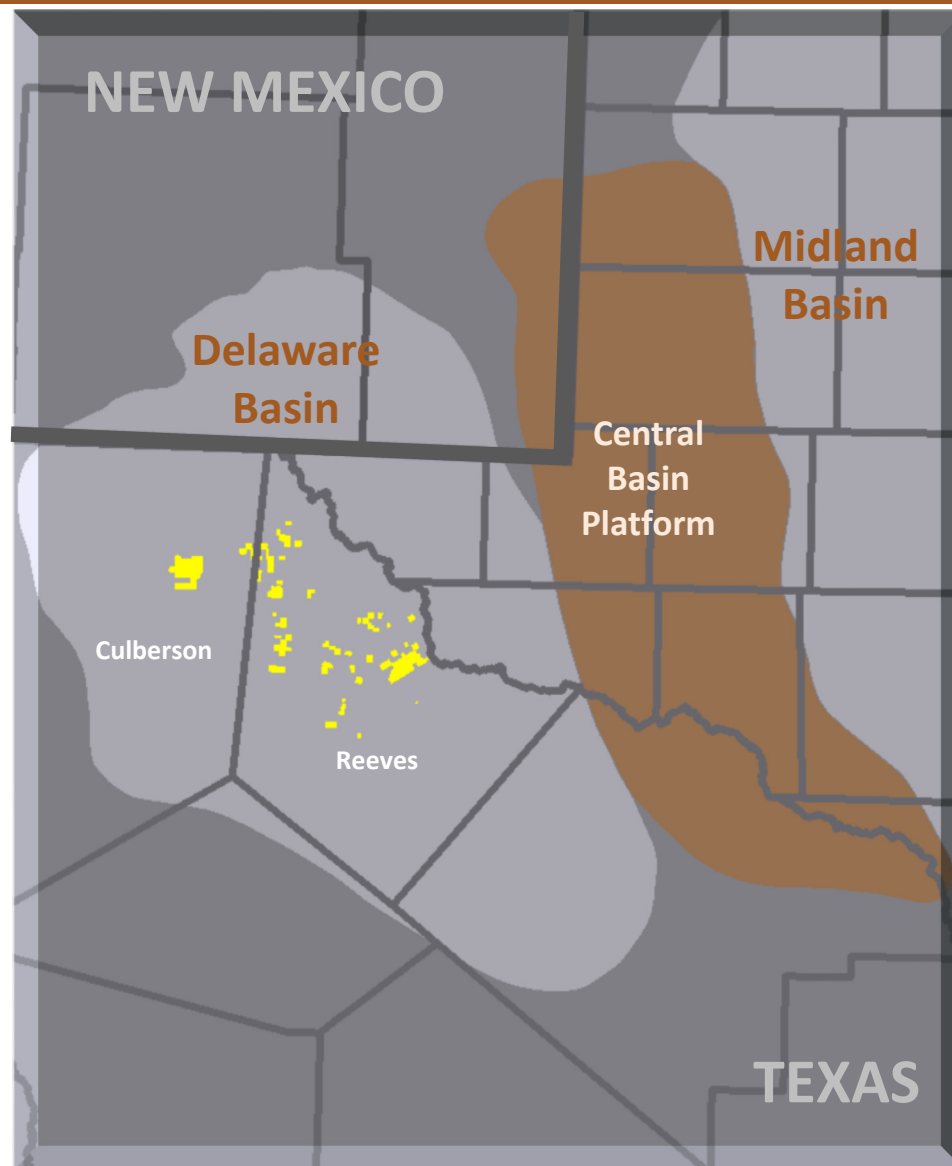
 PDC Acreage

Acquisition Attributes

- Large-scale acquisition of operated core acreage in top-tier Delaware basin
- Significant inventory of highly economic⁽¹⁾ Wolfcamp A, B and C wells with significant stacked pay in multiple additional intervals
- Future upside potential through: additional benches, downspacing, longer-laterals, completion enhancements and inventory expansion
- High working interest acreage with scalable, 100% owned and operated midstream infrastructure
- Liquid-rich profile (~65% liquids) complements Core Wattenberg

Key Benefits for PDC

- Significantly expanded inventory of highly economic projects
- Optionality to allocate capital across portfolio of two premier assets
- Visibility for material long-term value-added growth

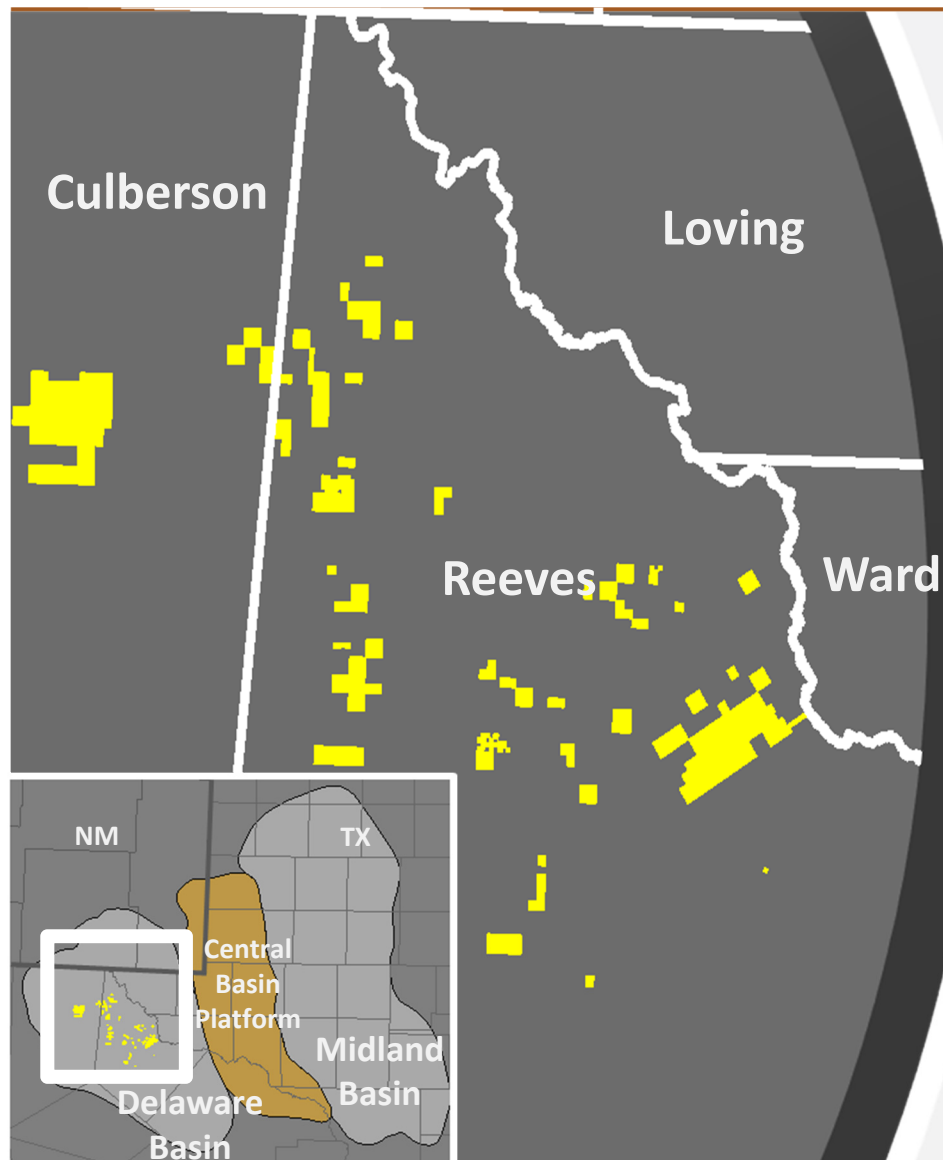




Key Delaware Basin Acquisition Highlights

Expected to Close in December 2016

 PDC Acreage



Deal Overview

- ~\$1.5 billion purchase price privately negotiated with Kimmeridge Energy Management Company
 - ~\$590 million privately placed equity to the seller and ~\$915 million of cash consideration
- ~57,000 net acres in Reeves (~41,000) and Culberson (~16,000) Counties, TX
- ~7,000 Boe/d net production
- ~530 MMBoe of estimated net reserves potential (65% liquids)
- ~710 currently identified potential locations in Wolfcamp A, B and C zones assuming a combined total of only 4-12 wells per section
 - Industry testing significantly tighter spacing and additional zones
- ~93% working interest (~100% operated)
- ~30% HBP – current development plan covers lease expirations

Premier Portfolio – Scalability in Two Top-Tier Basins



Pro Forma Core Wattenberg & Core Delaware Basins Portfolio (Upon Expected December 2016 Closing)

- Multiple years of highly economic drilling in Core Wattenberg and Core Delaware
 - Internal rates of return extremely competitive even in depressed commodity price environment
- Estimated combined net reserves potential in excess of 1 Billion Boe
 - Downspacing and delineation efforts are ongoing
- Approximately \$9 billion of combined future investment capital currently identified

GROSS INVENTORY LIFE⁽¹⁾

Core Wattenberg – ~10-12 Years

Core Delaware – ~15-20 Years

ESTIMATED POTENTIAL NET RESERVES

Core Wattenberg – ~550-600 MMBoe

Core Delaware – ~500-550 MMBoe

NET INVESTMENT CAPITAL

Core Wattenberg – ~\$5 Billion

Core Delaware – ~\$4 Billion

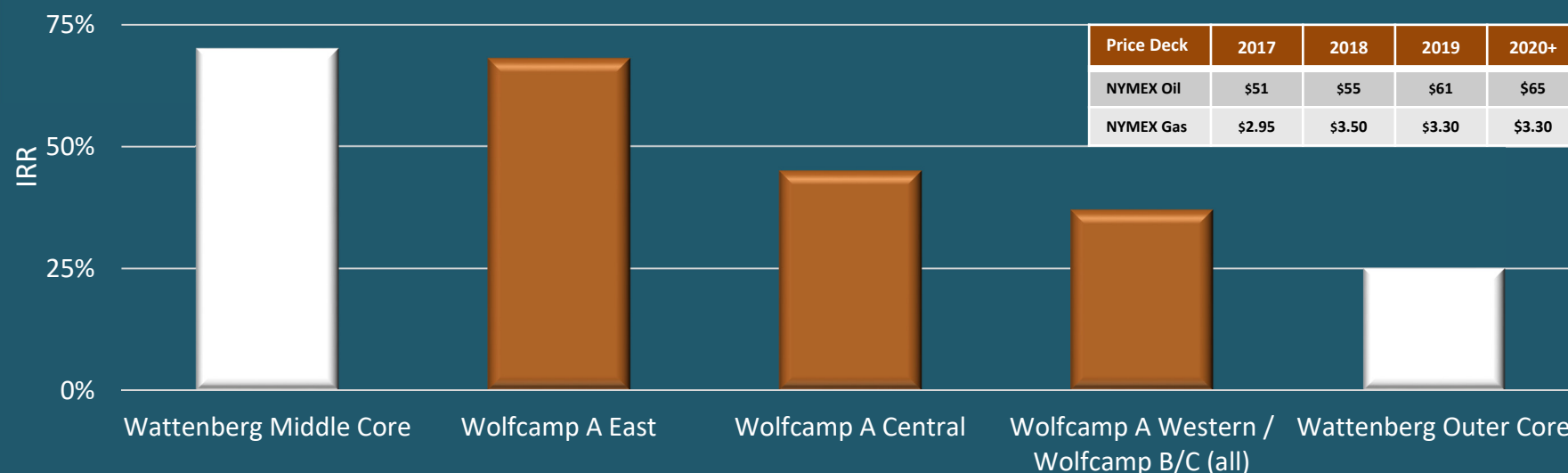


Competitive Returns Provide Portfolio Optionality

Pro Forma Acquisition Portfolio (Upon Expected December 2016 Closing)

- ~2,860 highly economic identified locations⁽¹⁾
- Competitive returns across portfolio provides optionality
- Competition for capital drives innovation and enhanced results
- Allocation of capital split between two top-tier basins

PDC Pro Forma Portfolio Type Well IRRs⁽²⁾



(1) YE15 2P Wattenberg locations of ~2,150 plus ~710 currently identified potential Delaware locations;

(2) CWC \$2.5MM (Watt.) & \$6.5MM (Del.); Reflects long-term differentials. Excludes lease acquisition and corporate level costs



Core Delaware – Acreage Overview

 PDC Acreage (Upon Expected December 2016 Closing)

93%

Average WI

100%

Approximate Operated Position

710

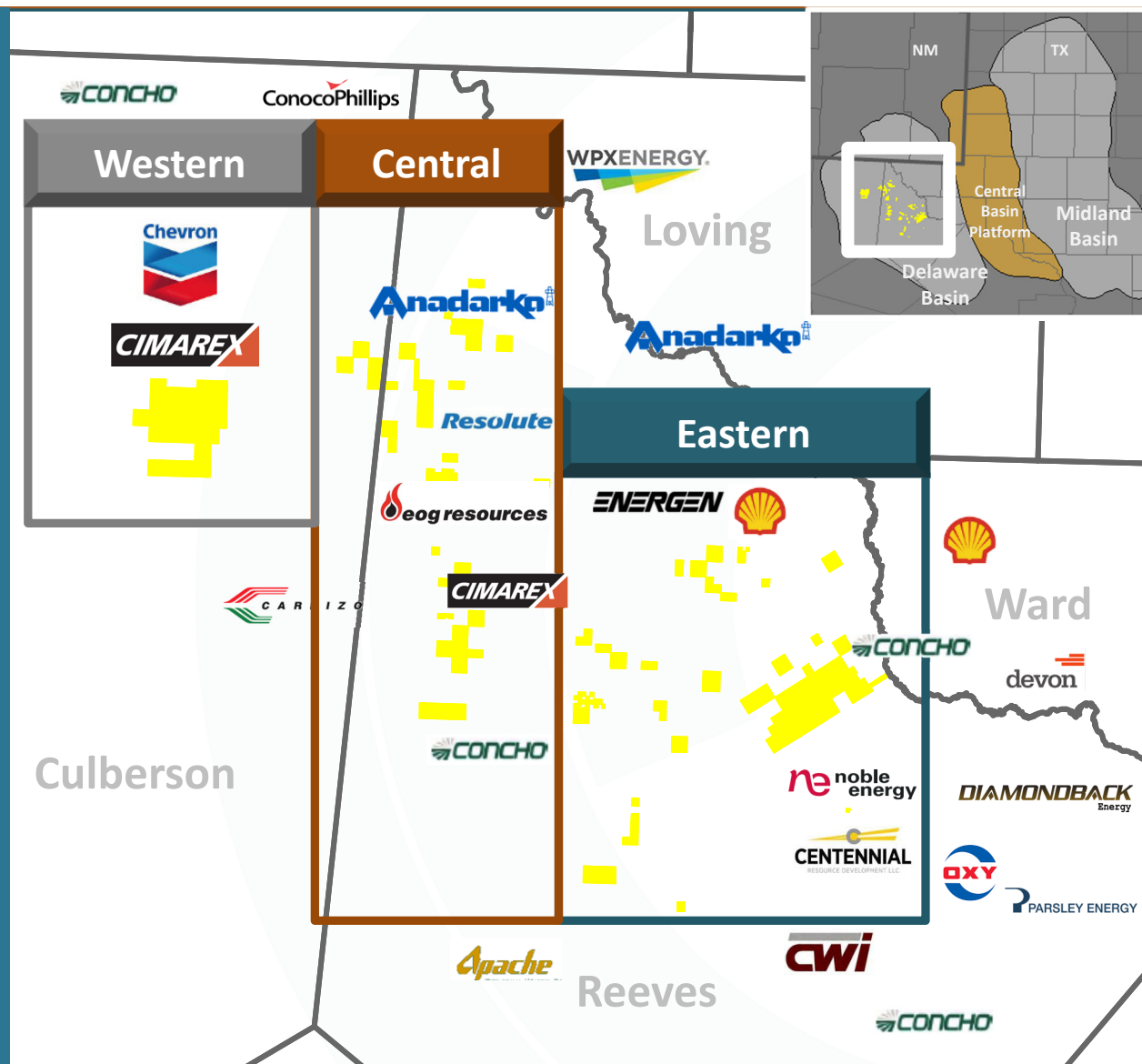
Currently Identified Locations
(Based on only 4-12 total wells per
section targeting Wolfcamp A/B/C)

15-20

Years of Drilling Inventory

1,000+

Average MBoe EURs/Well





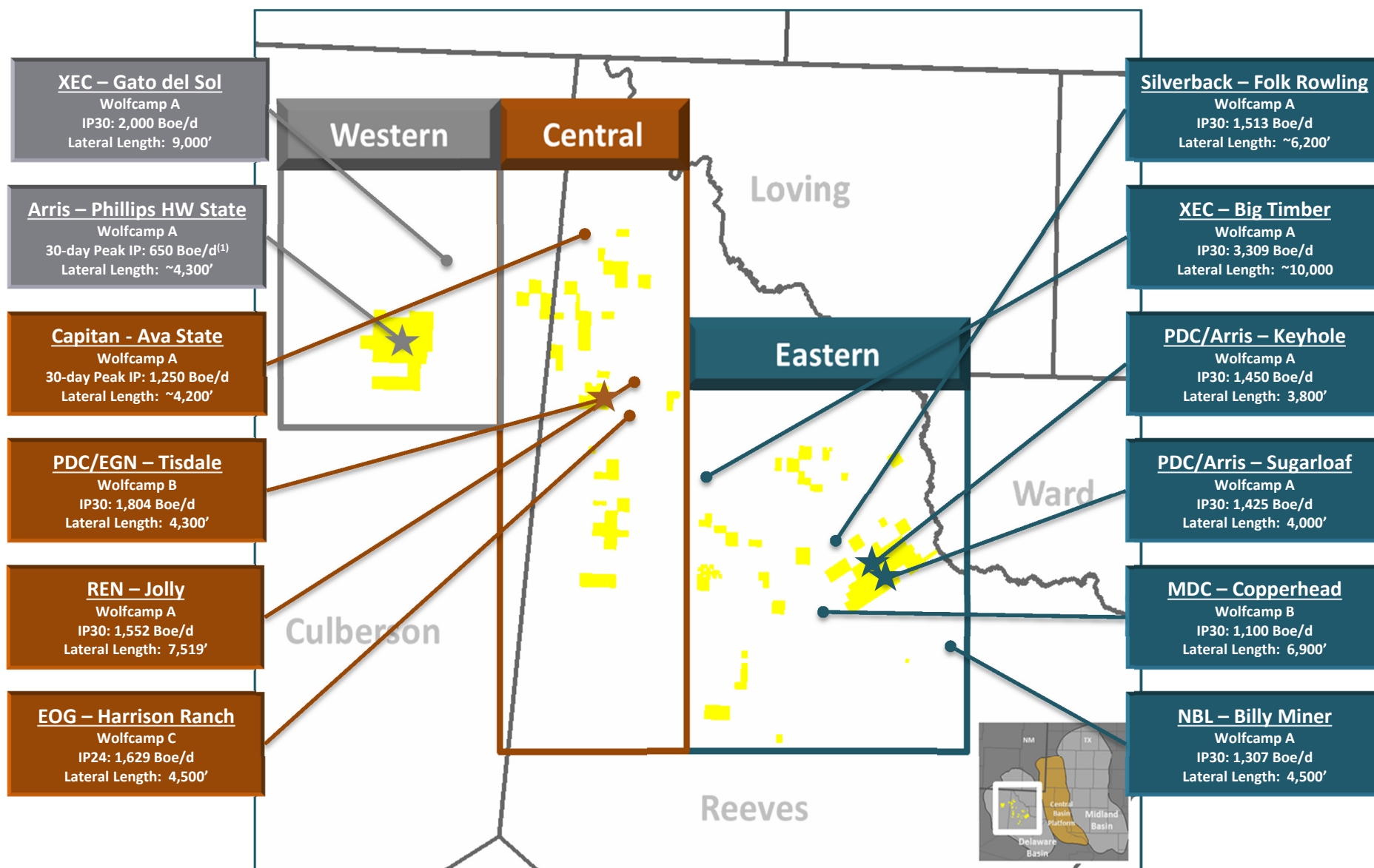
Core Delaware – Highly Productive Acreage



PDC Acreage



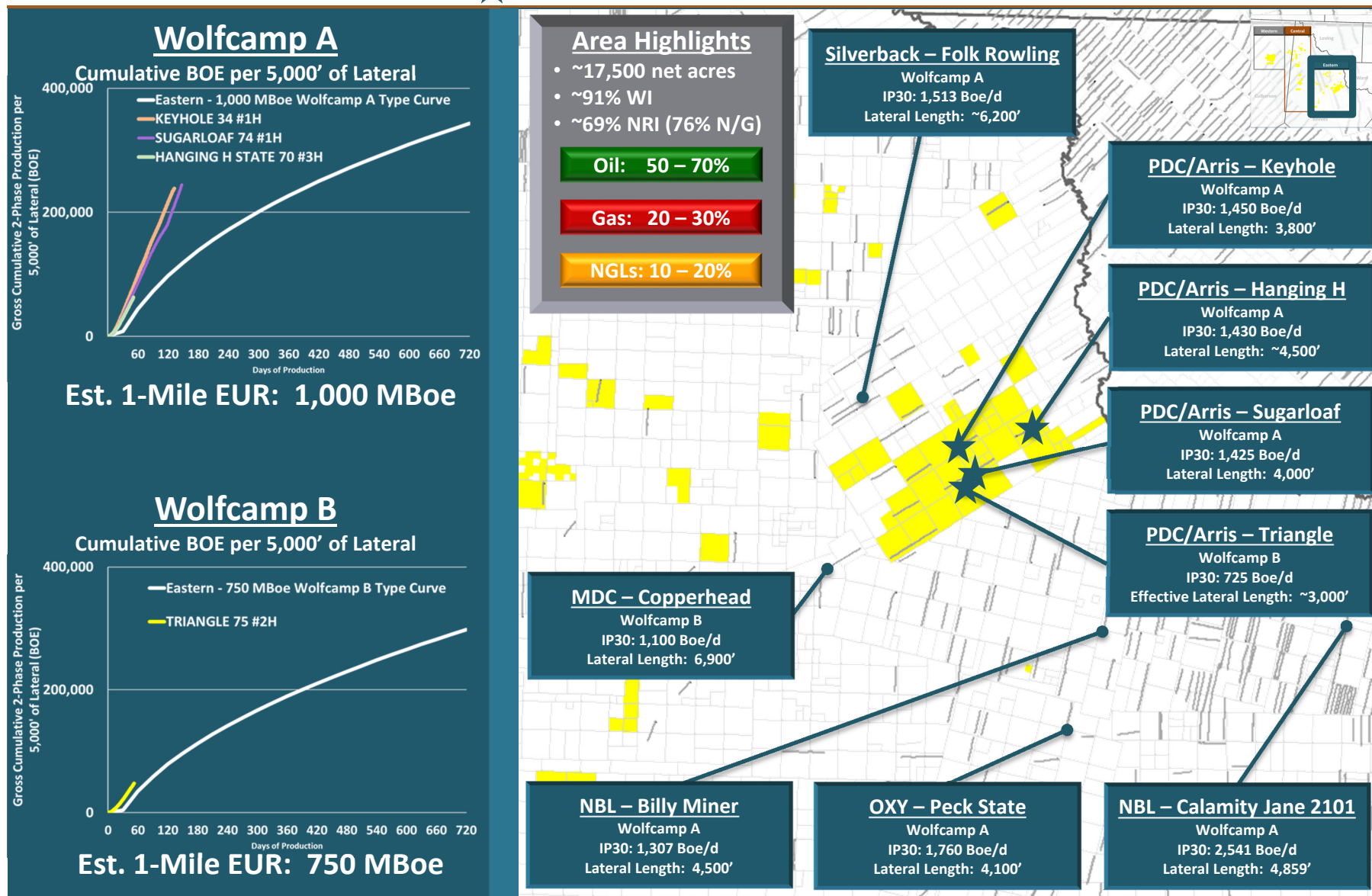
Acquired Well (Upon Expected December 2016 Closing)





Eastern Acreage Block: ~17,500 Net Acres

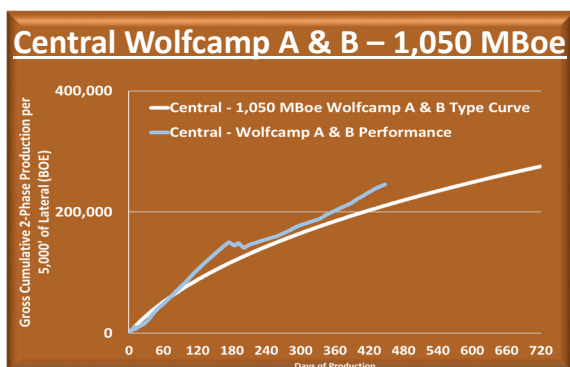
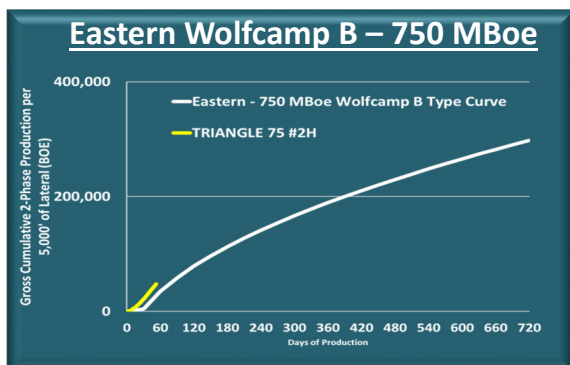
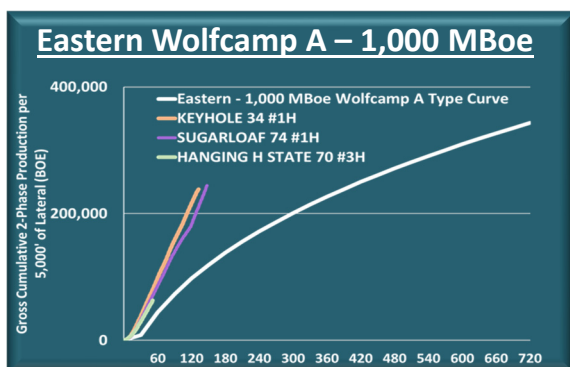
■ PDC Acreage / Existing Well ★ Acquired Well (Upon Expected December 2016 Closing)





Core Delaware – Detailed Acreage Block Overview

See Appendix For Additional Detail



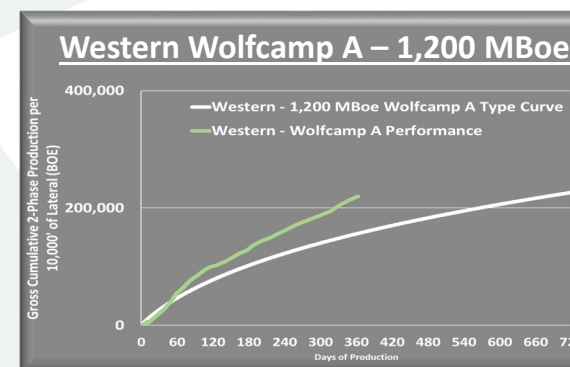
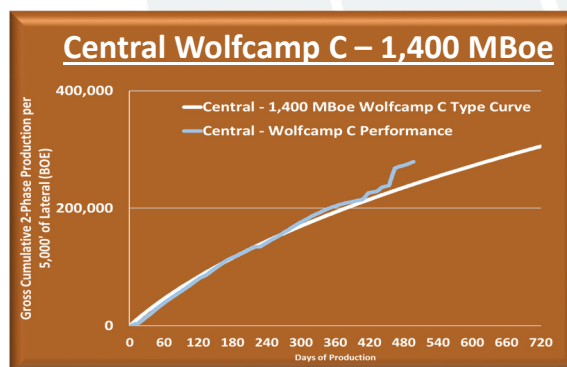
	Eastern Block	Central Block	Western Block
Net Acreage	17,500	23,500	16,000
Working Interest	91%	87%	100%

Commodity Mix

% Oil	50 – 70	30 – 50	20 – 50
% Gas	20 – 30	30 – 40	30 – 50
% NGLs	10 – 20	20 – 30	20 – 30

EUR Assumptions (MBoe) (1 Mile Lateral)

Wolfcamp A	1,000	1,050	1,200 ⁽¹⁾
Wolfcamp B	750	1,050	-
Wolfcamp C	-	1,400	-



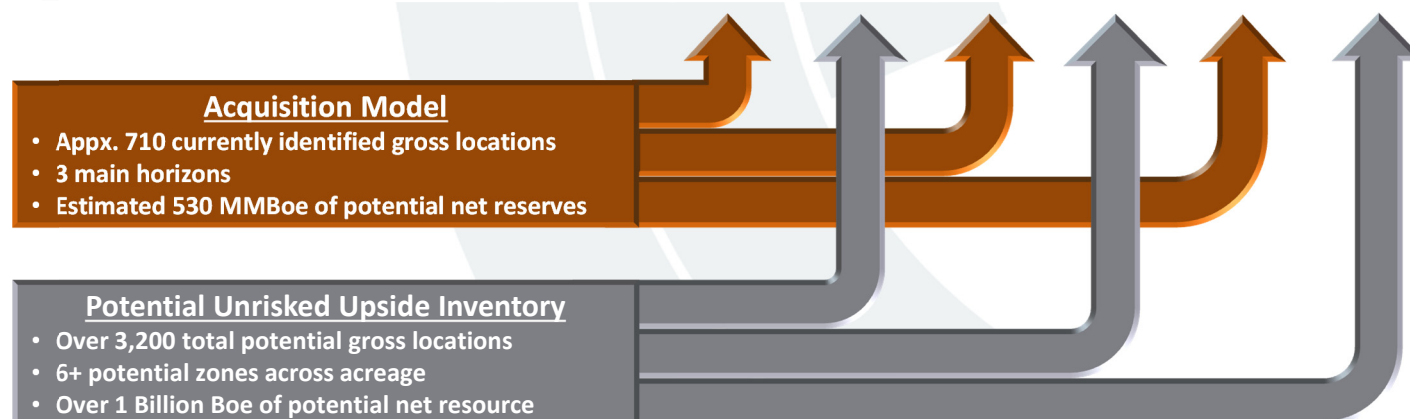
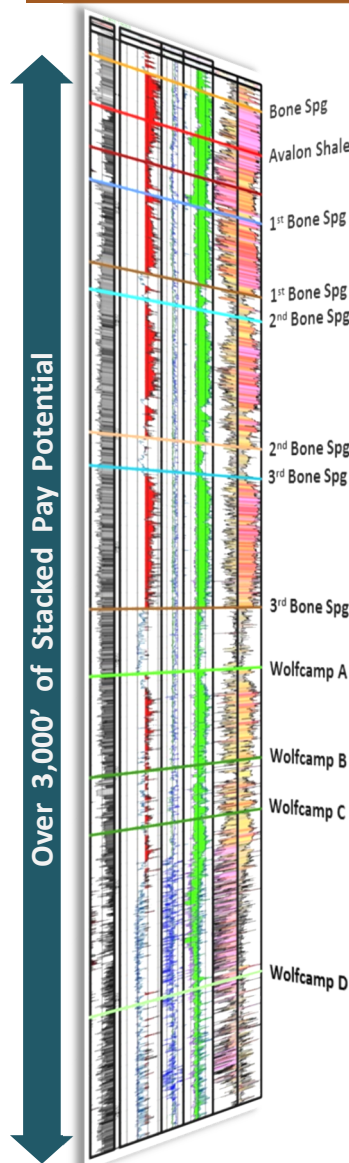


Core Delaware – Expansive Inventory Upside

Acquisition Model Assumes Maximum Density of Only 12 Wells per Section

Well Spacing & Inventory Summary

Bench	Max ACQ Spacing	Peer Tests	Eastern Inventory (17,500 net acres)		Central Inventory (23,500 net acres)		Western Inventory (16,000 net acres)	
	Wells/Sec	Wells/Sec	ACQ	Upside	ACQ	Upside	ACQ	Upside
1 st Bone Spg/Avalon	-	4 - 12 (XEC, CXO)	-	200	-	250	-	150
2 nd Bone Spg	-	4 - 6 (CXO)	-	125	-	175	-	125
3 rd Bone Spg	-	4 - 8 (NBL, CXO)	-	150	-	200	-	150
Wolfcamp A	8	8 - 12 (XEC, APC)	260	350	100	300	40	100
Wolfcamp B	4	6 - 8 (NBL, EGN)	150	250	80	125	-	150
Wolfcamp C	4	6 (EGN)	-	150	80	125	-	150
Total	4 - 12	32 - 52	410	1,225	260	1,175	40	825





Delaware Basin – Current Projects

 Rig Location

 Waiting-on-Completion

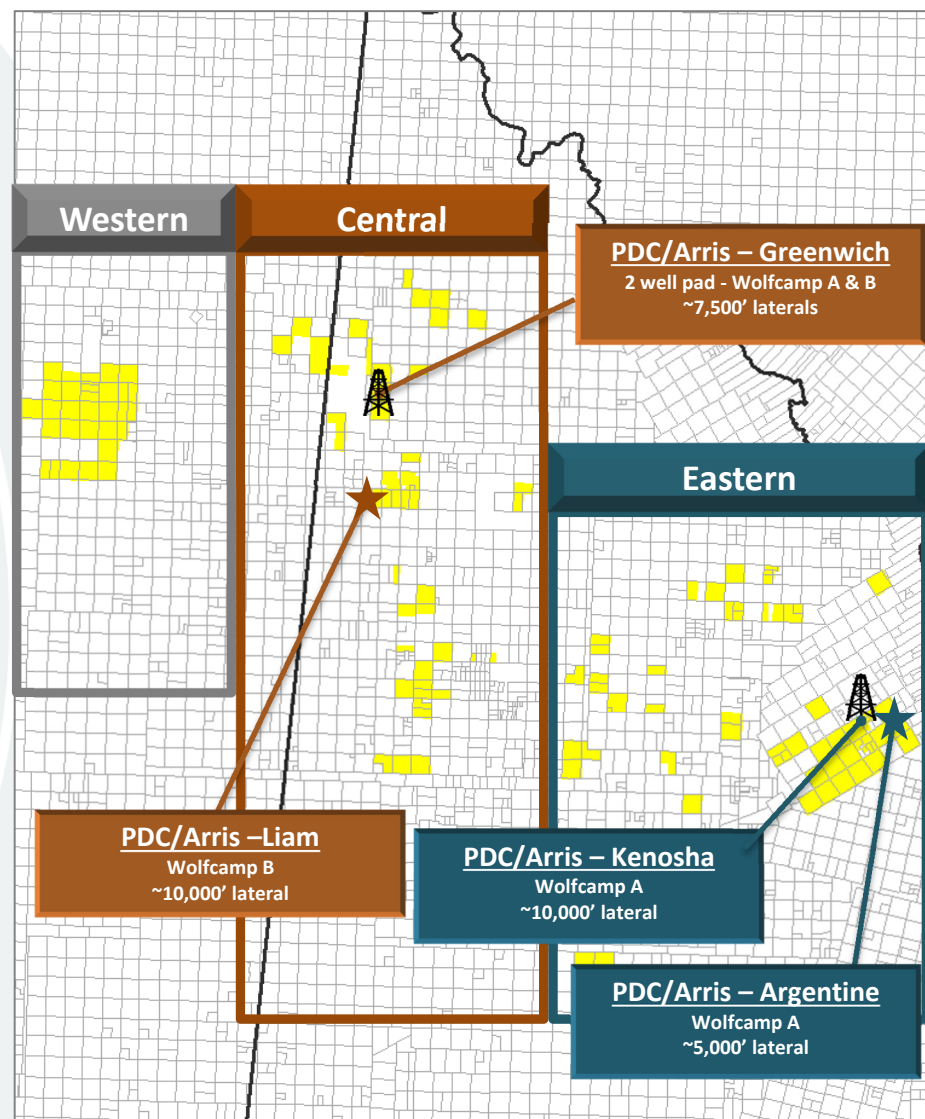
 PDC Acreage (Upon Expected December 2016 Closing)

2016 Initiatives

- Two rigs currently operated by seller
 - One rig in both Eastern and Central acreage
 - ~7,500 Boe/d current net production
- Building midstream infrastructure
 - Install ~10 miles of gas gathering lines
 - Drill water supply well and construct frac pits
 - Currently have 5 salt water disposal wells
- \$55 - \$65 million 2H16e capex
 - ~\$10 million in midstream capex
 - ~\$15 - \$20 million operated capex in December 2016 upon expected closing

Estimated Well Costs (millions)

Lateral Length	1-Well Pad	4-Well Pad
1 mile	\$6.5	\$5.8
1.5 miles	\$8.0	\$7.6
2 miles	\$9.5	\$9.1



Core Delaware – 100% Owned & Operated Midstream



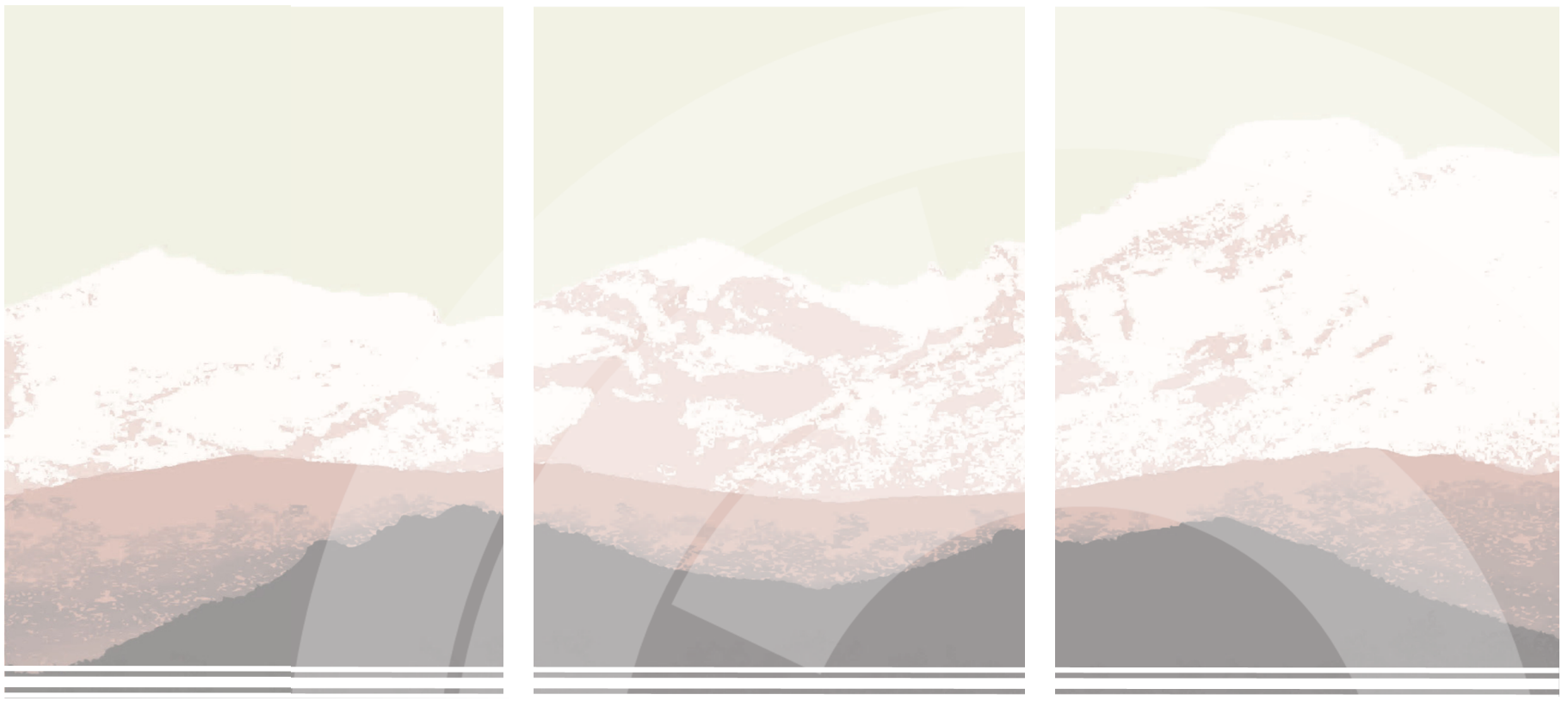
Future Upside from Buildout of 100% Owned and Operated Midstream Infrastructure

Midstream Assets: Current & Future

- Gas gathering systems to central delivery points (CDP)
- Water handling systems including pipelines and SWD wells
- Future potential for water supply via pipeline and supply wells
- Future potential crude oil gathering systems

Benefits of Infrastructure Ownership

- Ability to expand with drilling development program
- Potential cash flow stream from 3rd party volumes
- Facilitates timely well connects
- Water disposal/supply systems reduce operating costs & improve margins



CURRENT ASSET OVERVIEW



Core Wattenberg – Asset Summary

 PDC Acreage

96,000

~ Net Acres

100%

~ Acreage HBP

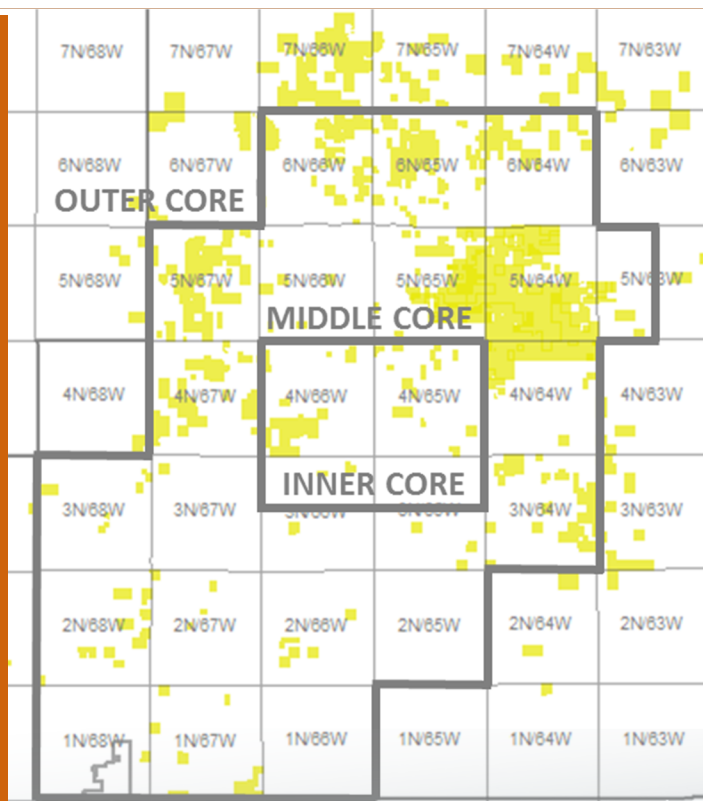
128/140

~Spuds

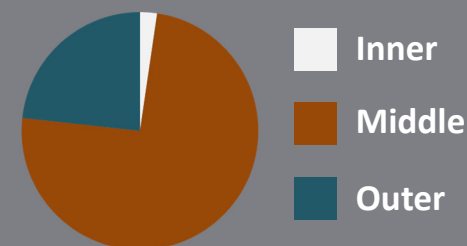
~TILs

2,150

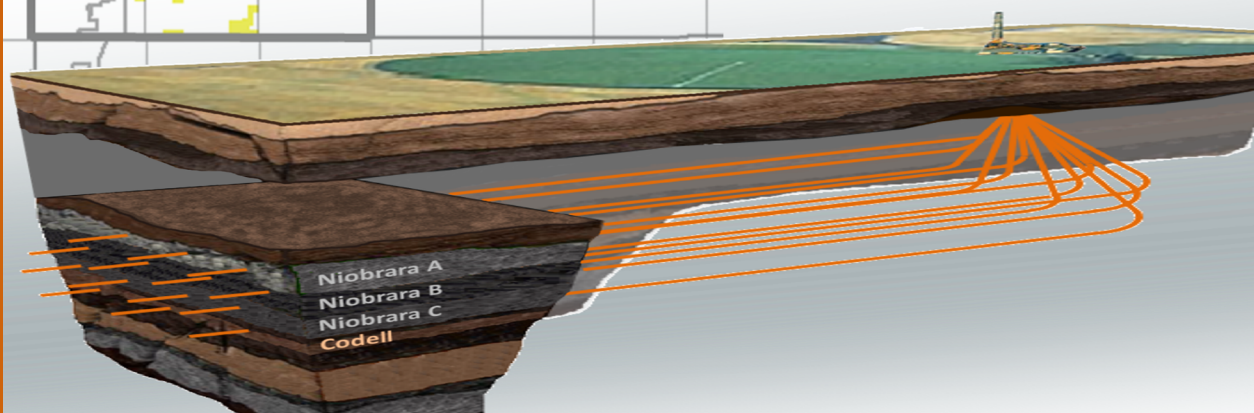
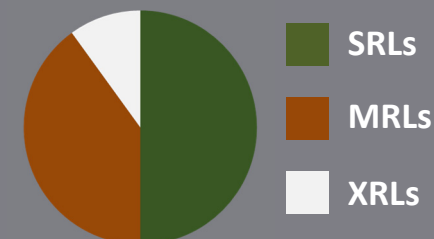
2P Hz Locations
(~4,700' avg. lateral length)



Wattenberg 2P Inventory⁽¹⁾



2016e TIL Breakdown



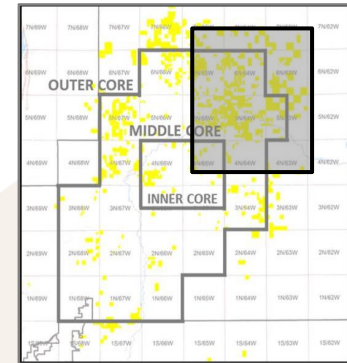


Core Wattenberg – Completed Strategic Acreage Trade

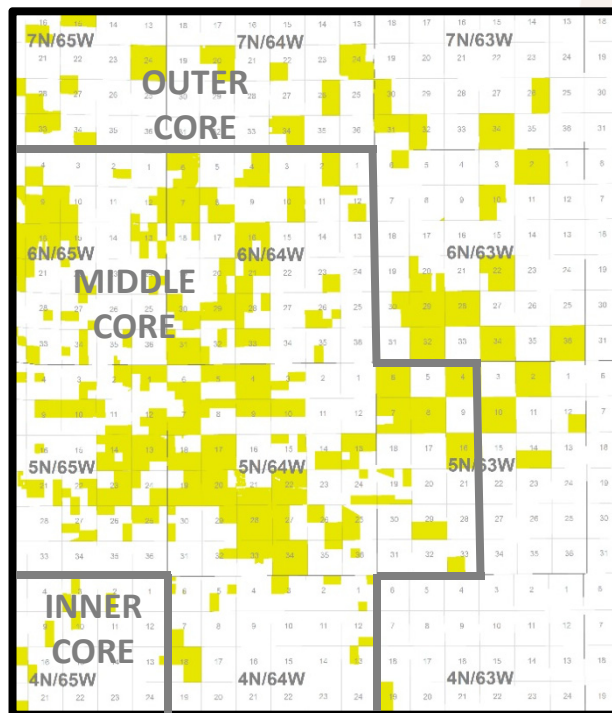
Trade with Noble Energy Closed September 28, 2016

 PDC Acreage

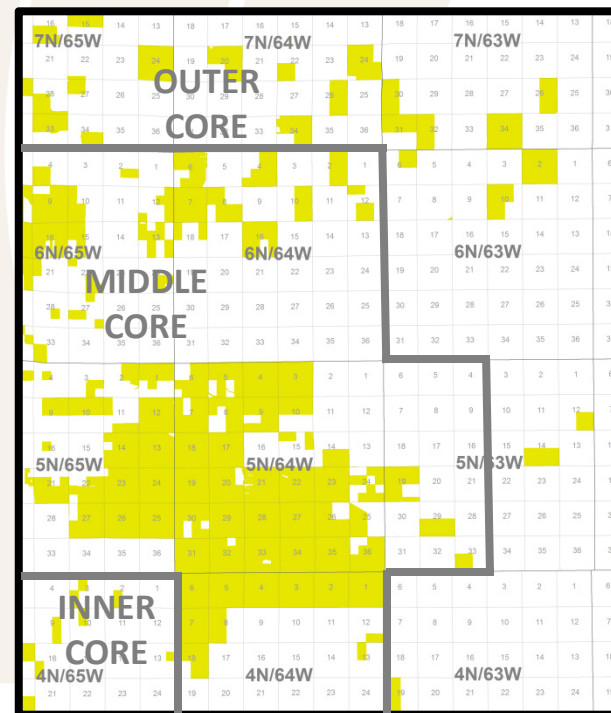
- Middle Core net acreage increased to ~70,300 from ~60,000
- Adds incremental value through increased working interests, improved synergies and enhanced long-term planning capabilities
- ‘Blocky’ acreage more conducive to long-lateral development
 - Reduced surface impact/footprint



PRE-TRADE



POST-TRADE

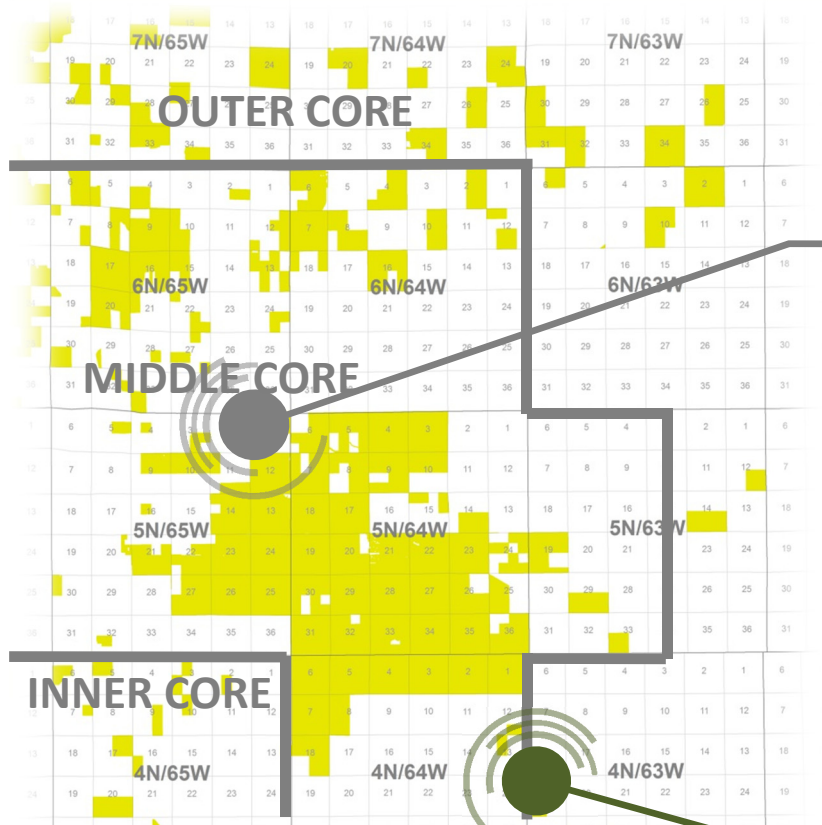




Positive Results Near Recently Consolidated Acreage

Strategic Acreage Trade Closed 9/28/16

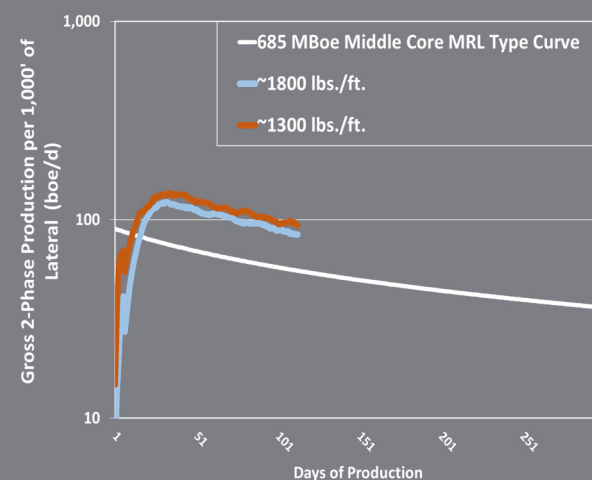
PDC Acreage



Closed 9/28/16	Pre-Trade	Post-Trade
2H16 Rig Count	4	3
Middle Core Net Acres	~60,000	~70,300
Outer Core Net Acres	~30,000	~21,500
2H16 Spuds	~60	~52
2H16 TILs	~80	~59
2H16 Average WI	~65%	~90%

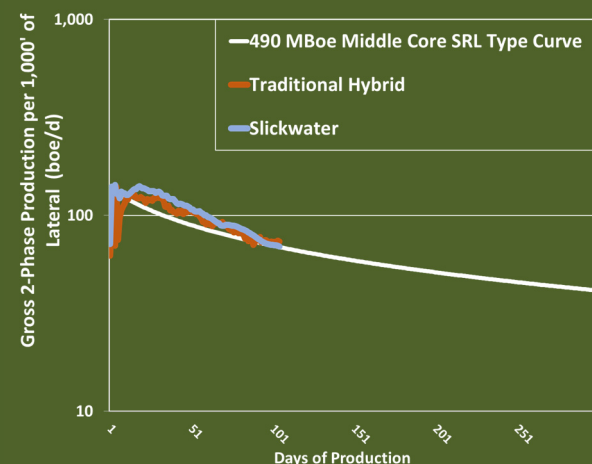
LDS Project

- 10 well pad
- 20 wells/section
- MRL Design
- TIL: 2Q16
- Tighter stage spacing
- Choke mgmt.
- 15 – 55% increase in proppant



Sater Project

- 8 well pad
- 16 wells/section
- SRL Design
- TIL: 3Q16
- 8 total wells
- 4 wells w/ Slickwater completion design



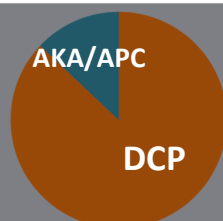
11/16/2016

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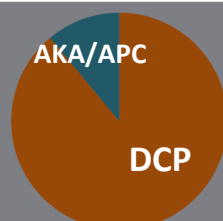


Core Wattenberg – Midstream Overview

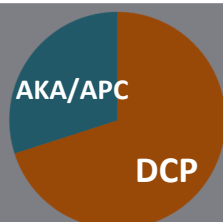
2013 Processing



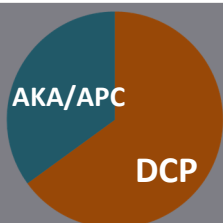
2014 Processing



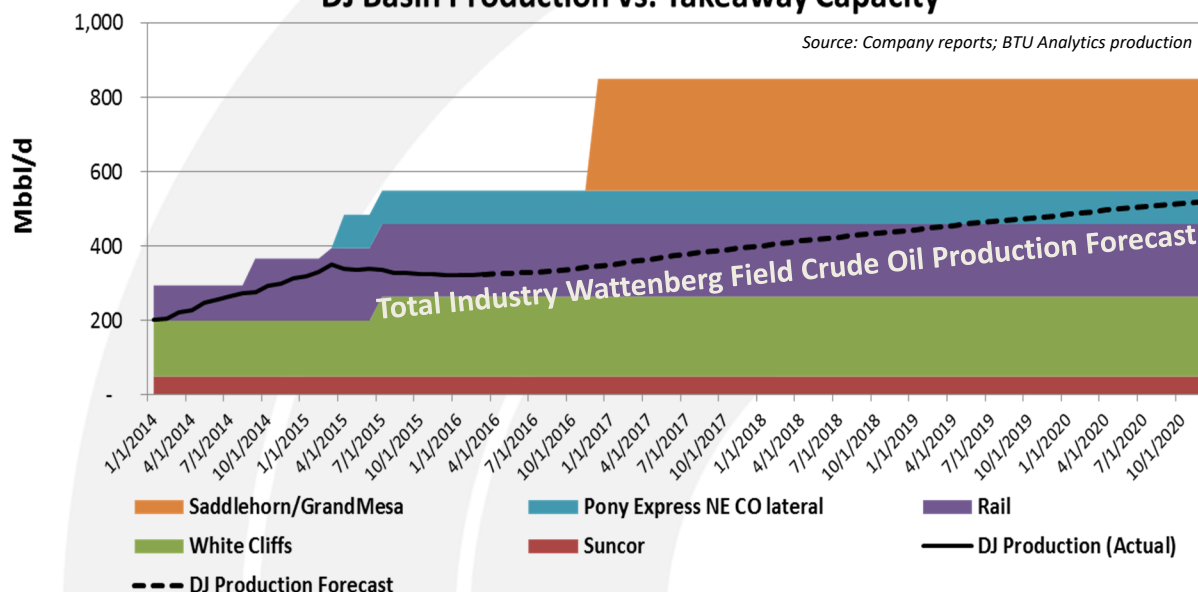
2015 Processing



2016e Processing



DJ Basin Production vs. Takeaway Capacity



OIL

- Multiple takeaway options (refinery, pipeline, trucking and rail)
- Expected takeaway capacity exceeds production forecasts for the basin well past 2020
- PDC has firm capacity of ~6,600 Bopd on White Cliffs pipeline

NATURAL GAS

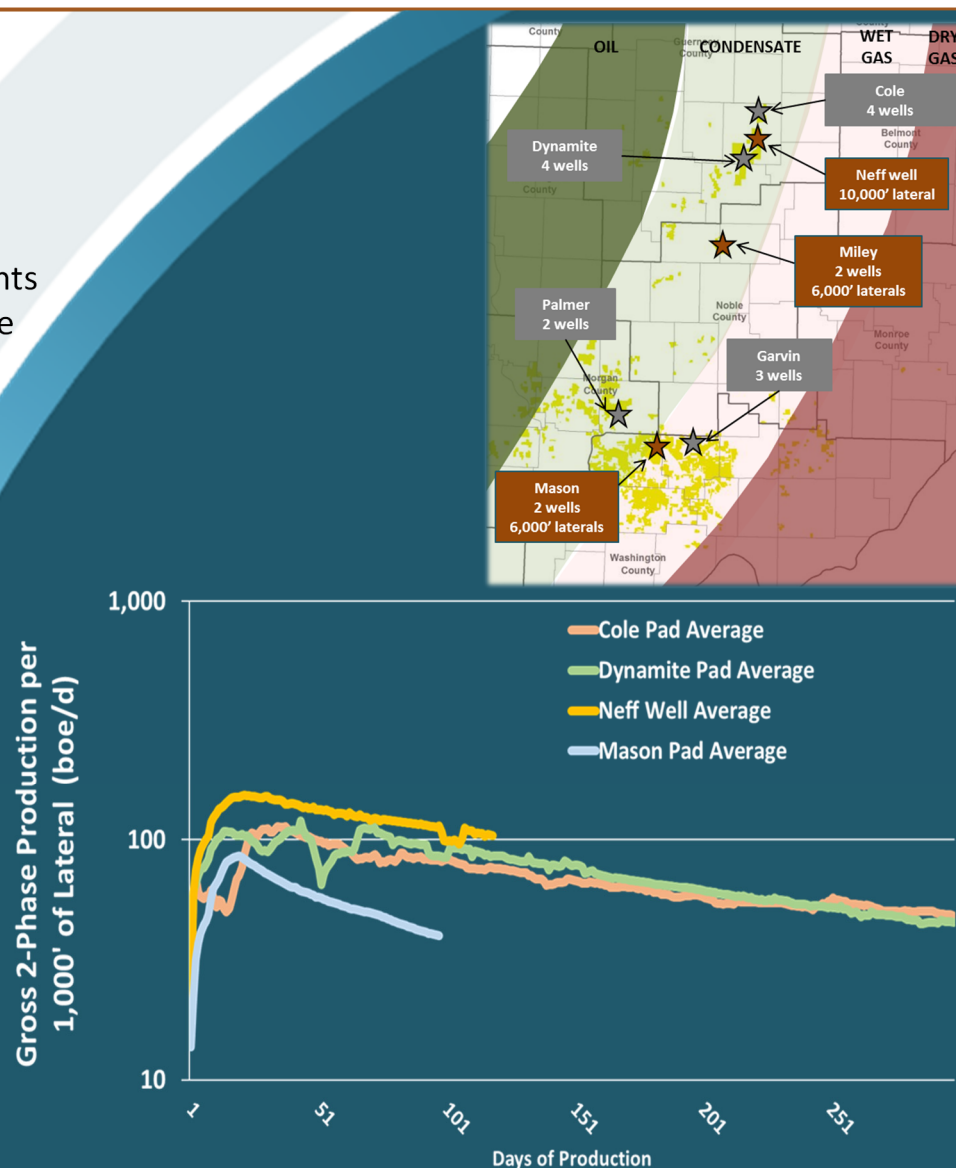
- Continued diversification of gas takeaway since 2013
- Line pressure not currently viewed as material issue related to future growth projections

Utica Update

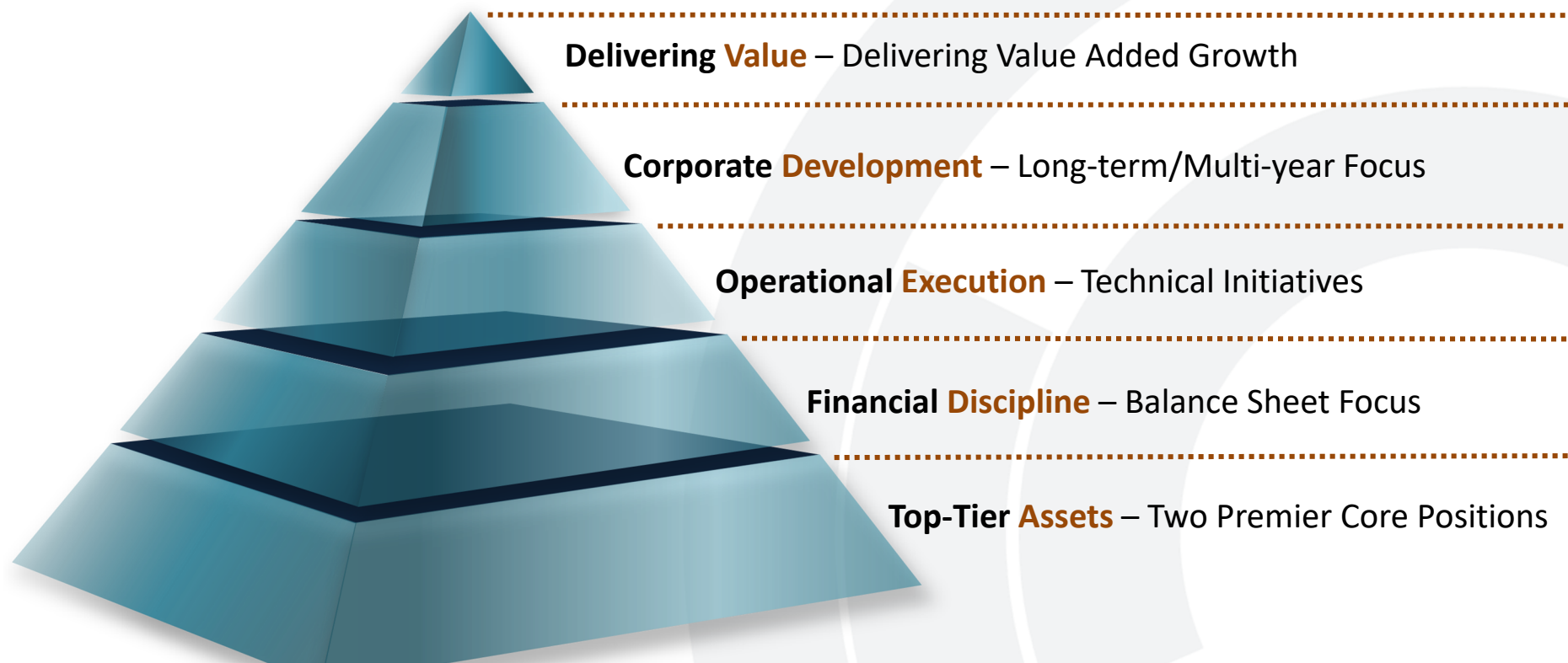


PDC Acreage

- ~65,000 net acres; ~50% HBP
- ~\$27MM capital plan in 2016
 - Neff well: May TIL
 - 10,000' lateral testing efficiency improvements
 - Best PDC Utica results per lateral foot to-date
 - Mason pad: June TIL
 - 6,000' lateral testing completion designs from Cole & Dynamite pads
 - Continue to monitor well performance
 - Miley pad: Expected 4Q16 TIL
 - Well-orientation testing
- Completed well costs of ~\$5.5 million for a 6,000' lateral well



PDC Energy – Vision and Strategy



Transformational Transaction

- Significant Increase in Reserves Potential
- Diversified Portfolio
- Continued Focus on Balance Sheet
- Extended Inventory Life
- Drives Shareholder Value
- Top-Tier Growth Outlook



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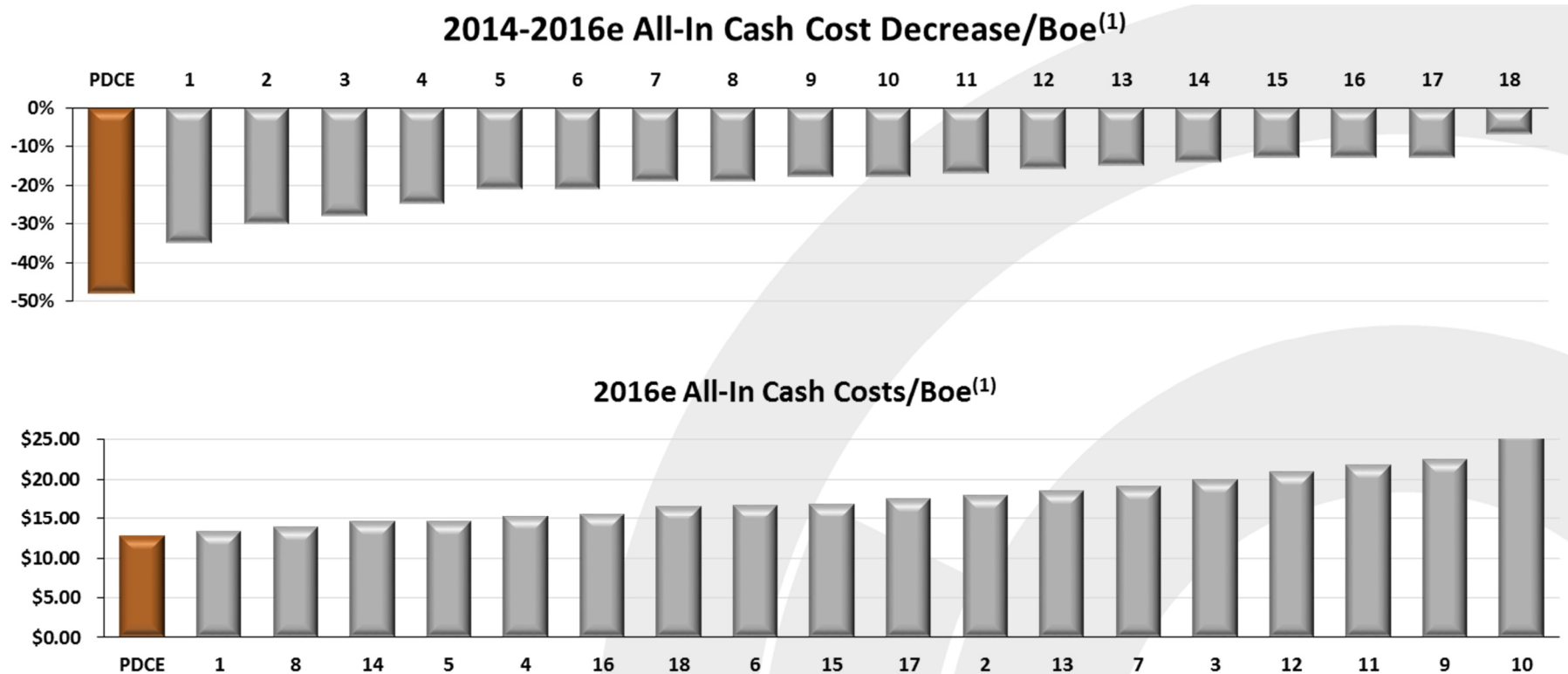


APPENDIX



Low Costs Continue to Drive Margins

Source: Wells Fargo Securities, LLC



- ~50% decrease in all-in cash operating costs since 2014 (including interest expense)
 - Substantial production increase drives reduced per Boe metrics
- Strong margins despite drop in crude prices
 - Systematically layering of hedges helps to lock in margins

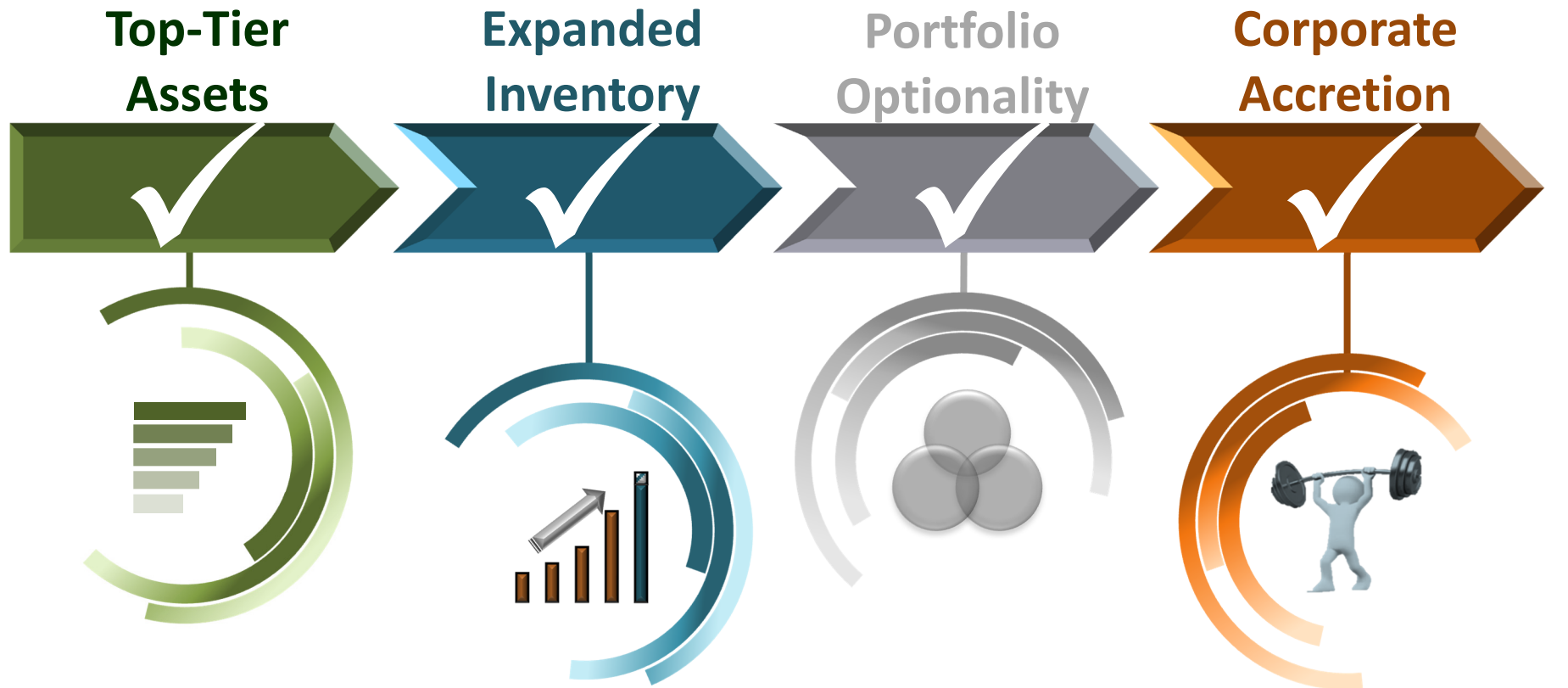
(1) Peers include: APA, APC, AREX, BBG, CRZO, CXO, DVN, EOG, EPE, FANG, LPI, NFX, PE, PXD, QEP, REN, SM, WLL; All-in cash costs include interest expense

11/16/2016



Established Acquisition Strategy

Originally Presented at April 2016 Analyst Day



- Must compete with Wattenberg
- Core position; quality geology
- Favorable liquids mix

- Existing base production
- Decade-plus of inventory
- Potential for downspacing

- Provides new core area
- Provides portfolio diversification
- Potential bolt-ons/land trades

- Accretive to company
- Provides long-term catalysts
- Grows PDC to mid-cap space

Acquisition Meets All Criteria

- IRRs comparable to Wattenberg
- Core operated acreage
- ~65% liquids with ~42% oil

- ~7,000 Boe/d net production
- 15-20 year inventory
- Downspacing opportunities

- Allocation of capital
- Multi-basin operations
- Highly active A&D market

- Accretive to company
- EUR enhancement potential
- Impactful, large-scale deal



Central Acreage Block: ~23,500 Net Acres



PDC Acreage



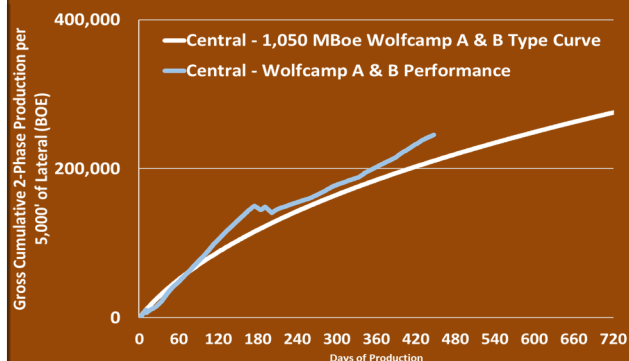
Existing Well



Acquired Well

Wolfcamp A / Wolfcamp B

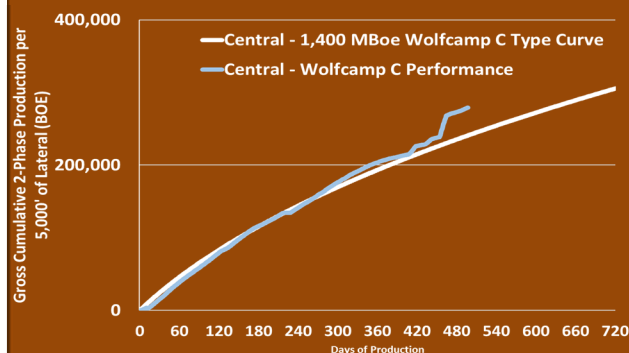
Cumulative BOE per 5,000' of Lateral



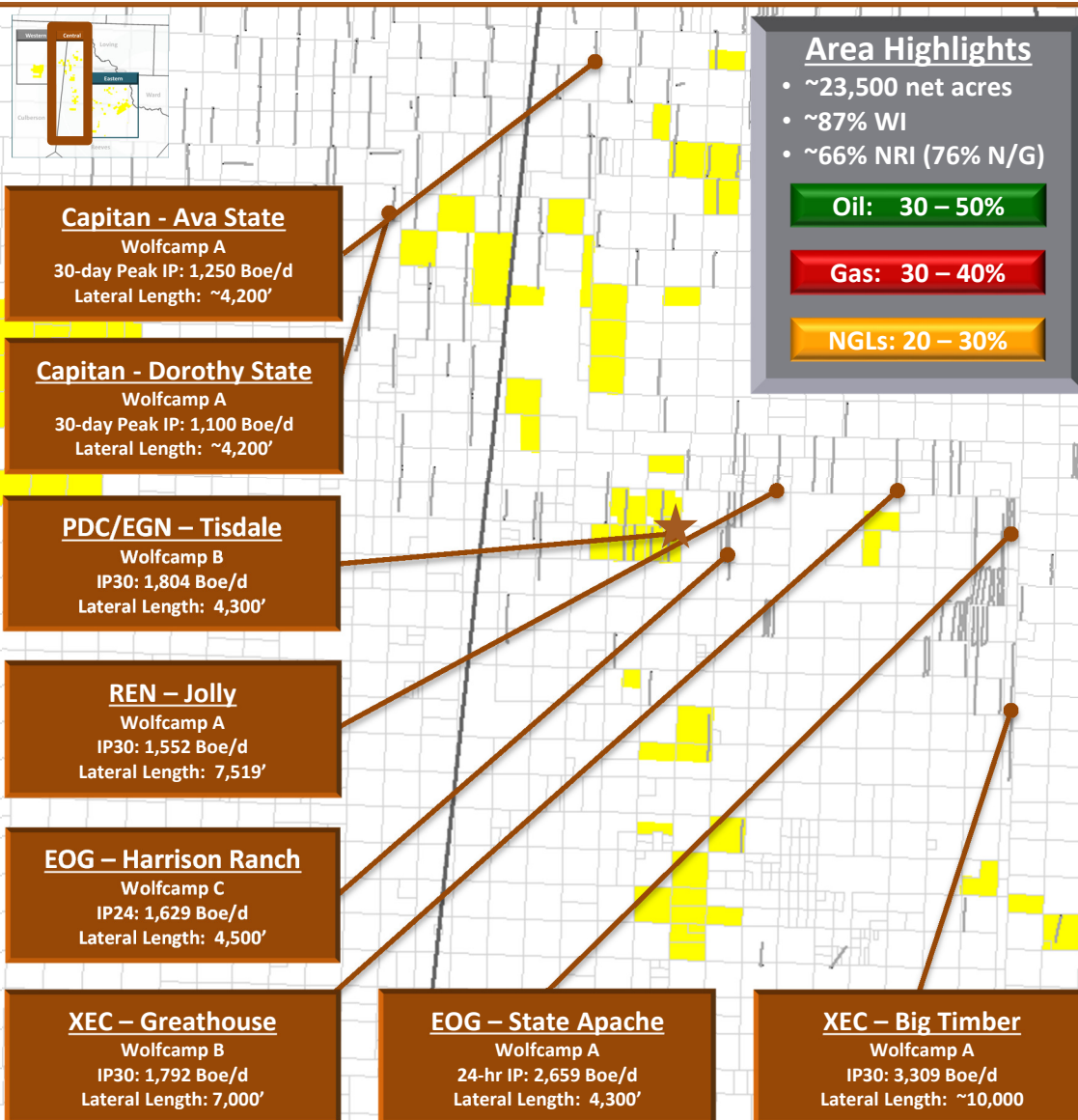
Est. 1-Mile EUR: 1,050 MBoe

Wolfcamp C

Cumulative BOE per 5,000' of Lateral



Est. 1-Mile EUR: 1,400 MBoe



Western Acreage Block: ~16,000 Net Acres



PDC Acreage



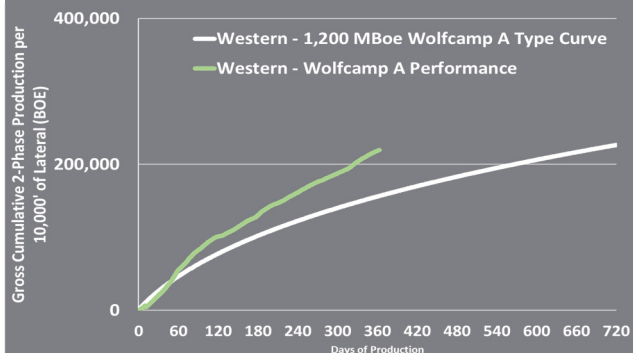
Existing Well



Acquired Well

Wolfcamp A

Cumulative BOE per 10,000' of Lateral



Est. 2-Mile EUR: 1,200 MBoe

Additional Upside Potential

- Lower Wolfcamp zones not included in current inventory/reserves
- Strong results from nearby industry test of lower Wolfcamp zones
- Significant upside potential in Wolfcamp A based on offset industry downspacing tests

Area Highlights

- ~16,000 net acres
- ~100% WI
- ~78% NRI (78% N/G)

Oil: 20 – 50%

Gas: 30 – 50%

NGLs: 20 – 30%

XEC – Gato del Sol

Wolfcamp A
IP30: 2,000 Boe/d
Lateral Length: 9,000'

Capitan – Georgette State

Wolfcamp A
30-day Peak IP: 1,050 Boe/d
Lateral Length: ~8,700'

Capitan – W A State

Wolfcamp A
30-day Peak IP: 1,750 Boe/d
Lateral Length: ~7,000'

Arris – Phillips HW State

Wolfcamp A
30-day Peak IP: 650 Boe/d⁽¹⁾
Lateral Length: ~4,300'

Capitan – Karen Fee

Wolfcamp A
IP30: 925 Boe/d
Lateral Length: 4,500'

XEC – California Chrome

Wolfcamp A
30-day Peak IP: 1,450 Boe/d
Lateral Length: ~9,000'

Delaware Basin Netback Summary



CRUDE OIL

Key Highlights

- Currently trucked at competitive rates
- Sufficient long-term takeaway from Permian basin
 - Approx. 400 MBbls/d of excess pipeline capacity

Est. Average Netback

NYMEX Oil Price: \$50/Bbl

PDC Netback: \$46/Bbl

Oil Deduct: \$4.00/Bbl

NGLs

Key Highlights

- NGLs piped via multiple pipelines to Gulf Coast
- NGL yields vary based on C2 rejection/recovery

Est. Average Netback

NYMEX Oil Price: \$50/Bbl

PDC Netback: \$15/Bbl

% of NYMEX Oil: 30%

NATURAL GAS

Key Highlights

- Strong relative basis pricing
- Limited term acreage dedication
 - Provides future upside
- No volume commitments

Est. Average Netback

NYMEX Gas Price: \$3.00/MMbtu

PDC Netback: \$2.04/MMbtu

% of NYMEX Gas: 68%



Pro Forma 3-Year Outlook

Organic Base Case
 Range
 Pro Forma Acquisition
 Range

>100

Est. Combined 2018 Daily Production
(Mboe/d)

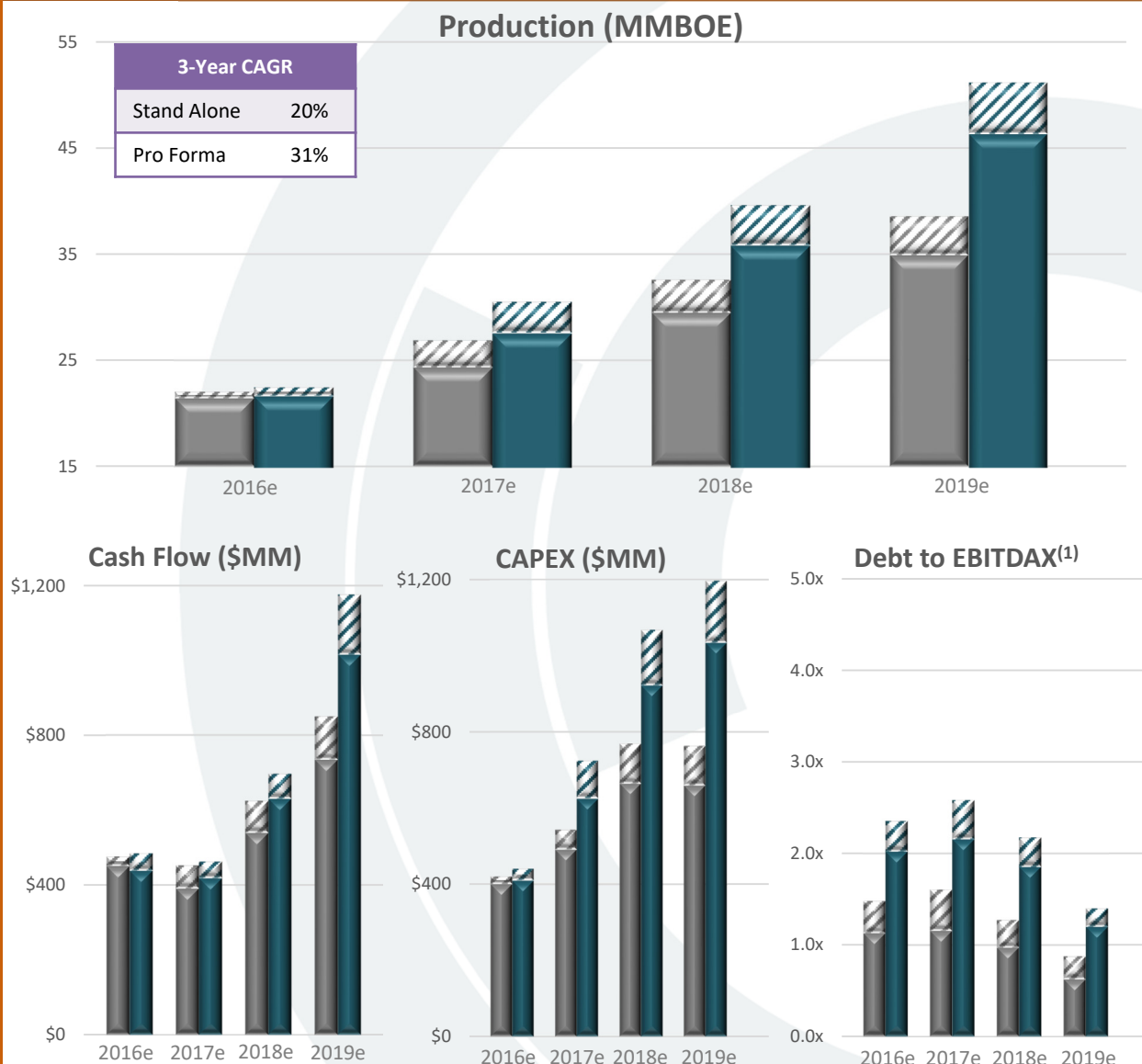
40%

Est. Pro Forma Oil Production Mix

<2.5x

Target Debt/EBITDAX⁽¹⁾

	2016	2017	2018	2019
NYMEX Oil	\$42	\$51	\$55	\$61
NYMEX Gas	\$2.37	\$2.95	\$3.50	\$3.30





Updated 2016 Core Wattenberg EUR Analysis

Based on Evaluation of Public Production Data

PDC Acreage

2,500

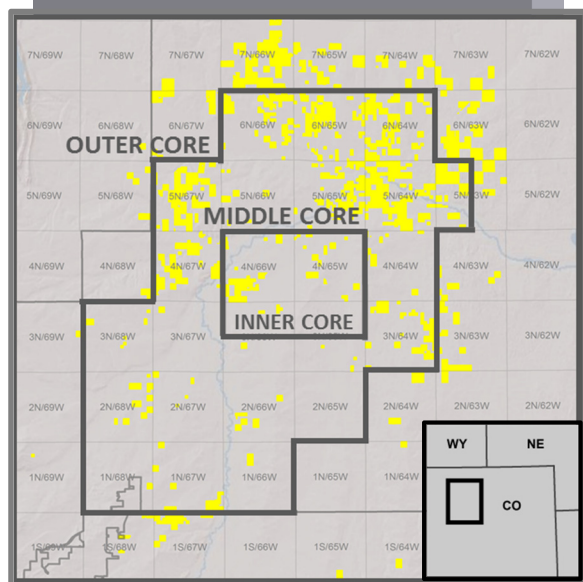
Wells Included in Study

2.6-3.6

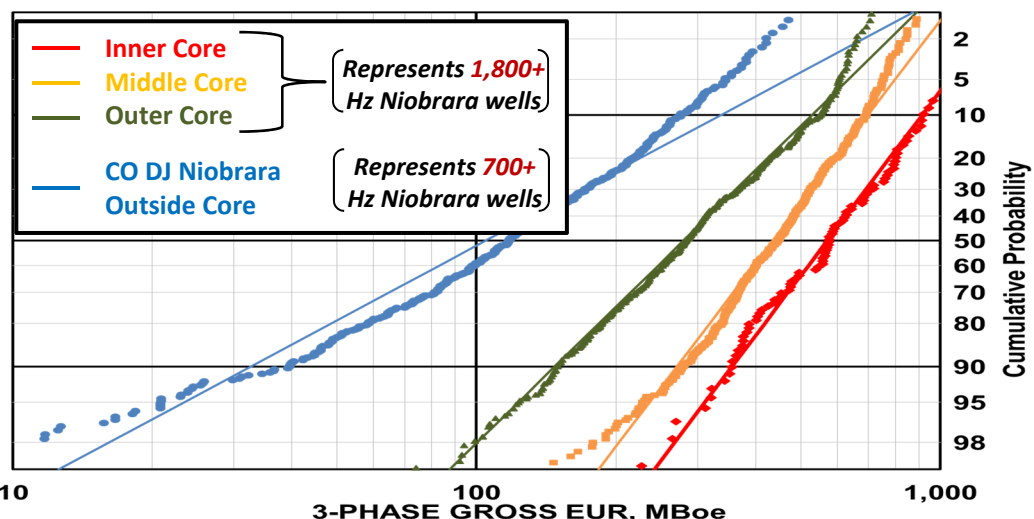
EUR Variability Ratio Range for
Core Wattenberg

4,200'

Normalized Lateral Length



2016 EUR ANALYSIS



Area	Industry Average 3-Phase EUR	EUR Variability (P10/P90) Ratio
Inner Core	600 MBoe	2.6
Middle Core	460 MBoe	2.6
Outer Core	311 MBoe	3.6
Non-Core DJ Basin	149 MBoe	10.3

(1) Based upon publicly available data as of December 31, 2015 for wells in Colorado with 4+ months of production. Assumes an NGL yield of 90 Bbls/MMcf and a 20% gas shrink factor for all wells.

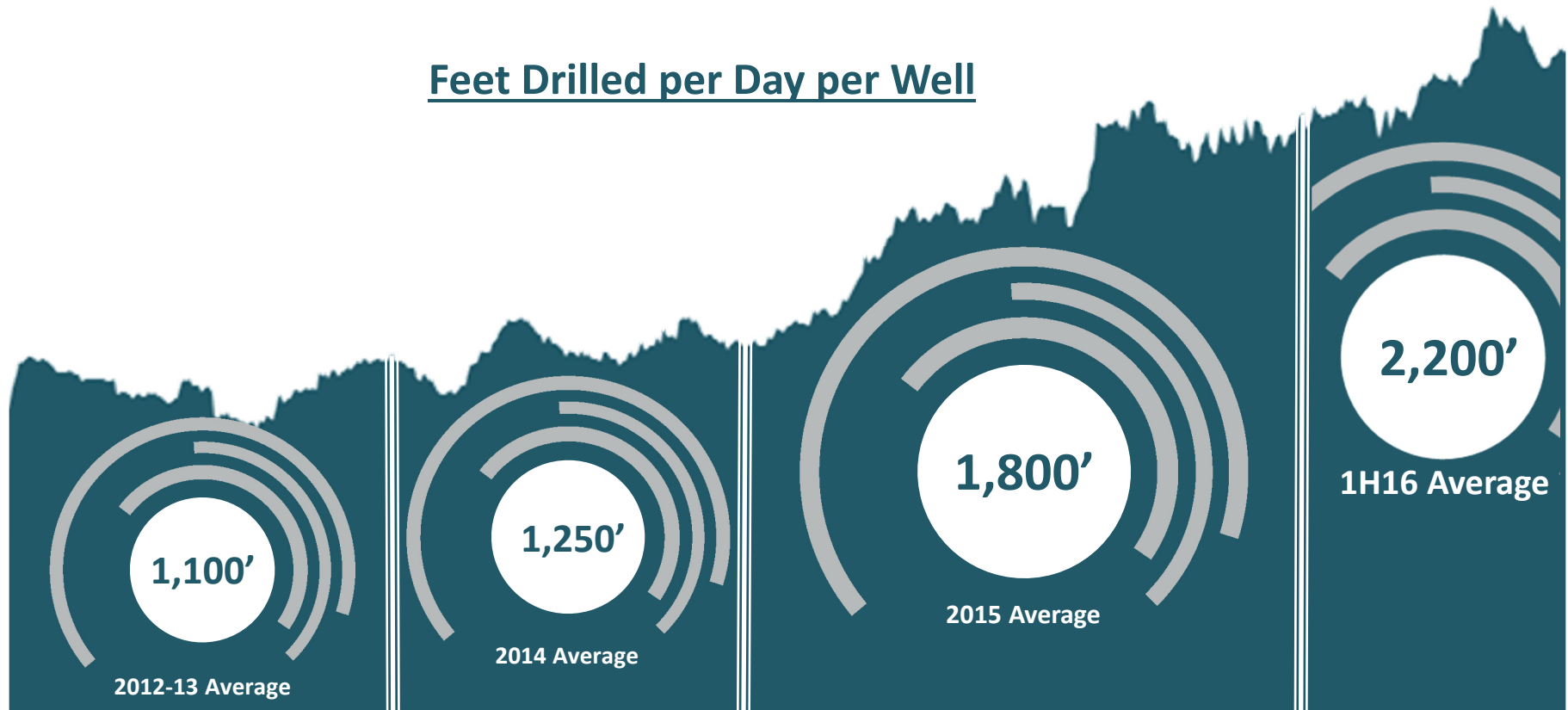
11/16/2016

Significant Drilling Efficiencies Improvements



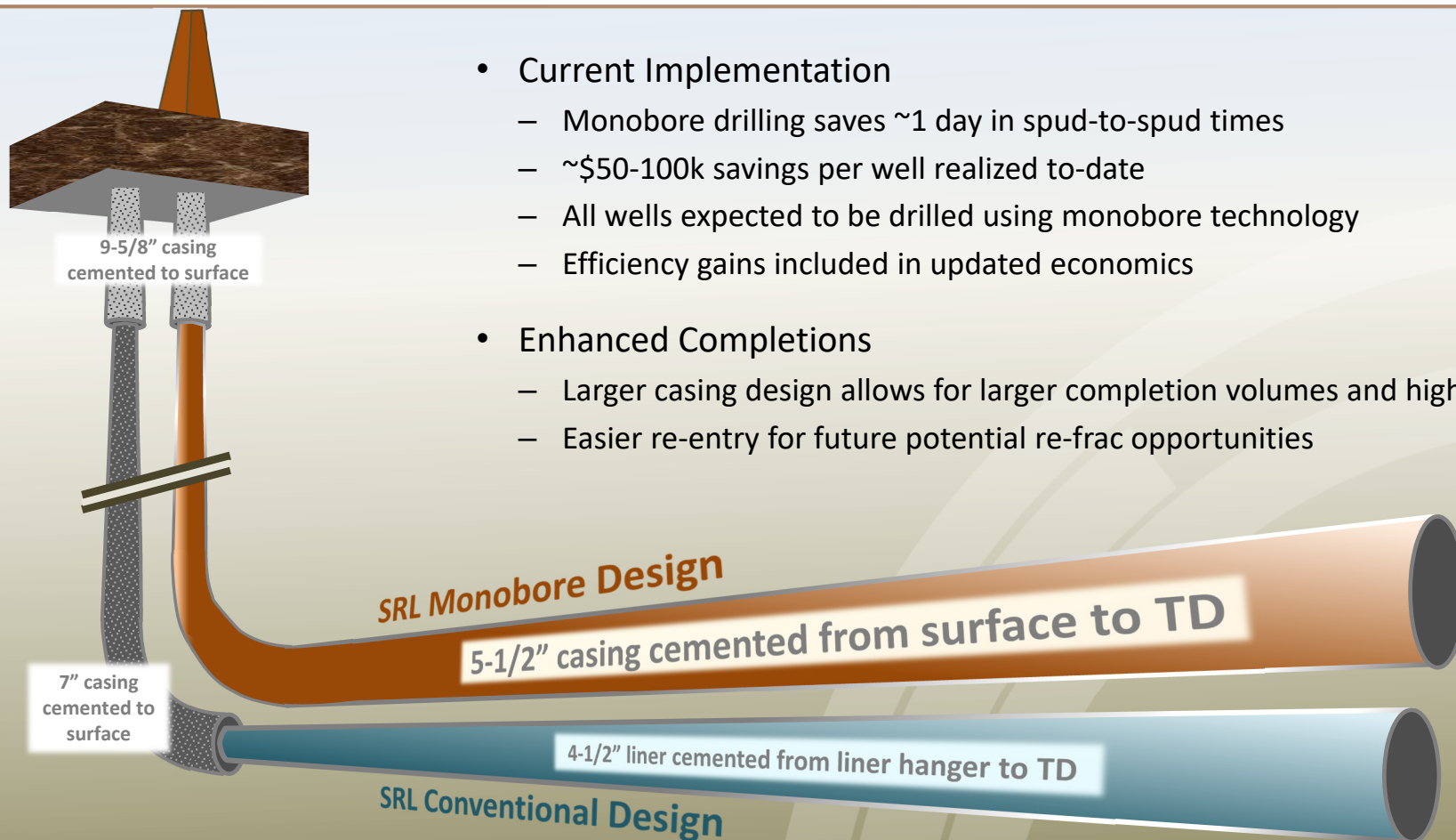
- 2016 drill times improved by ~75% since 2014 and ~100% since 2013
- 2016 efficiency gains further improving drill times
 - Original forecast of ~1,900 feet drilled per day per well

Feet Drilled per Day per Well





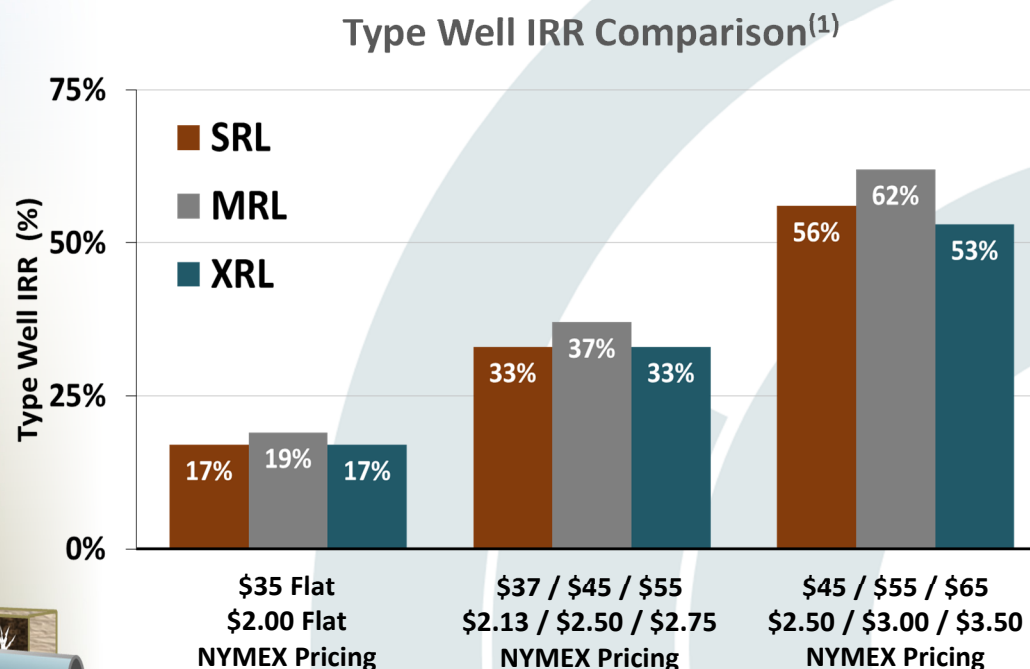
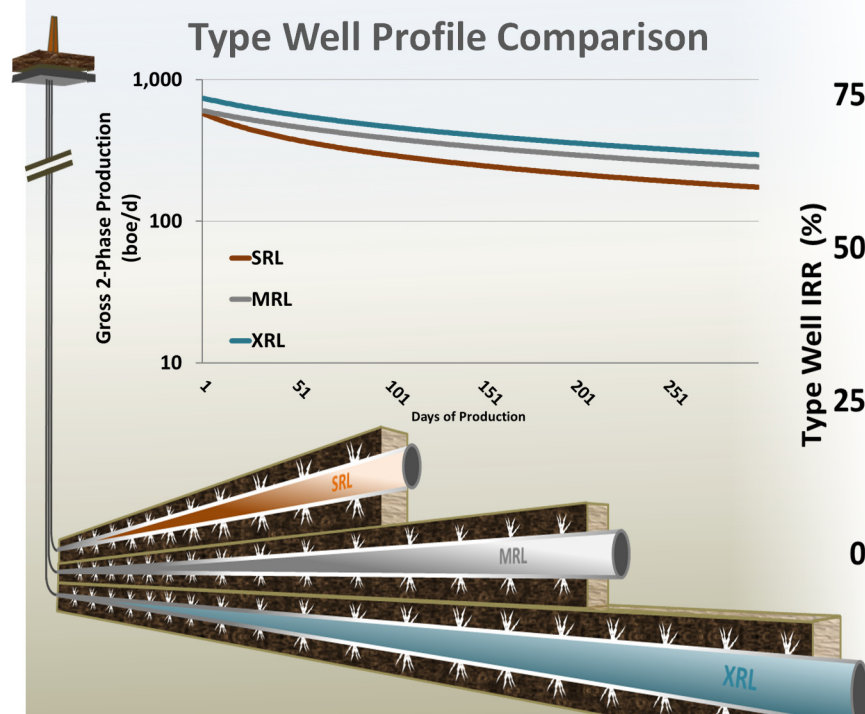
Monobore Drilling Gains To-Date



- Current Implementation
 - Monobore drilling saves ~1 day in spud-to-spud times
 - ~\$50-100k savings per well realized to-date
 - All wells expected to be drilled using monobore technology
 - Efficiency gains included in updated economics
- Enhanced Completions
 - Larger casing design allows for larger completion volumes and higher rates
 - Easier re-entry for future potential re-frac opportunities

Design Comparison	Conventional	Monobore
Avg. Drill Times	7 – 9 days	6 – 8 days

Middle Core – Inventory Provides Resilient Returns



Lateral Type	Lateral Length (feet)	EUR (MBoe)	Capital Cost (MM)	F&D Cost (per Boe)	IRR ⁽²⁾	PV10 ⁽²⁾ (MM)
SRL	4,200	490	\$2.5	\$6.37	33%	\$1.4
MRL	6,900	685	\$3.5	\$6.39	37%	\$2.4
XRL	9,500	850	\$4.5	\$6.61	33%	\$2.8

(1) 2016, 2017, 2018 pricing scenarios; third year pricing held flat in out years. Reflects long-term differentials. Excludes lease acquisition and corporate-level costs.
 (2) Esc. pricing: \$37, \$45, \$55 flat annual NYMEX Oil, \$2.13, \$2.50, \$2.75 flat annual NYMEX Gas. Reflects long-term differentials. Excludes lease acquisition and corporate-level costs.

Reconciliation of Non-US GAAP Financial Measures



In millions, except per share data

Adjusted EBITDA from net income (loss):

	Three Months Ended Sept 30,		Nine Months Ended Sept 30,	
	2016	2015	2016	2015
Net loss	(\$23.3)	(\$41.5)	(\$190.3)	(\$71.3)
(Gain) loss on commodity derivative instruments	(\$19.4)	(\$123.5)	\$62.3	(\$141.2)
Net settlements on commodity derivative instruments	\$47.7	\$68.0	\$167.9	\$162.5
Interest expense, net	\$20.1	\$10.7	\$40.9	\$31.8
Income tax provision	(\$12.0)	(\$21.2)	(\$112.2)	(\$40.6)
Impairment of properties and equipment	\$0.9	\$154.0	\$6.1	\$161.2
Depreciation, depletion, and amortization	\$112.9	\$81.0	\$317.3	\$206.9
Accretion of asset retirement obligations	\$1.8	\$1.6	\$5.4	\$4.7
Adjusted EBITDA	\$128.7	\$129.1	\$297.4	\$314.0
Weighted-average diluted shares outstanding	48.8	40.1	45.7	38.8
Adjusted EBITDA per diluted share	\$2.64	\$3.22	\$6.50	\$8.09

Adjusted EBITDA from net cash from operations activities:

	Three Months Ended Sept 30,		Nine Months Ended Sept 30,	
	2016	2015	2016	2015
Net cash from operating activities	\$163.0	\$136.5	\$360.8	\$283.0
Interest expense, net	\$20.1	\$10.7	\$40.9	\$31.8
Stock-based compensation	(\$4.1)	(\$4.8)	(\$15.2)	(\$14.3)
Amortization of debt discount and issuance costs	(\$9.9)	(\$1.8)	(\$12.9)	(\$5.3)
Gain on sale of properties and equipment	\$0.2	\$0.1	-	\$0.3
Other	(\$0.2)	\$2.2	(\$41.6)	\$7.9
Changes in assets and liabilities	(\$40.4)	(\$13.8)	(\$34.6)	\$10.6
Adjusted EBITDA	\$128.7	\$129.1	\$297.4	\$314.0
Weighted-average diluted shares outstanding	48.8	40.1	45.7	38.8
Adjusted EBITDA per diluted share	\$2.64	\$3.22	\$6.50	\$8.09

Reconciliation of Non-US GAAP Financial Measures



In millions, except per share data

	Three Months Ended Sept 30,		Nine Months Ended Sept 30,	
	2016	2015	2016	2015
Adjusted net income (loss) from net income (loss):				
Net loss	(\$23.3)	(\$41.5)	(\$190.3)	(\$71.3)
(Gain) loss on commodity derivative instruments	(\$19.4)	(\$123.5)	\$62.3	(\$141.2)
Net settlements on commodity derivative instruments	\$47.7	\$68.0	\$167.9	\$162.5
Tax effect of above adjustments	(\$10.8)	\$21.1	(\$87.6)	(\$8.1)
Adjusted net loss	(\$5.8)	(\$75.9)	(\$47.7)	(\$58.1)
Weighted-average diluted shares outstanding	48.8	40.1	45.7	38.8
Adjusted net loss per diluted share	(\$0.12)	(\$1.89)	(\$1.04)	(\$1.50)

	Three Months Ended Sept 30,		Nine Months Ended Sept 30,	
	2016	2015	2016	2015
Adjusted cash flows from operations from net cash from operating activities:				
Net cash from operating activities	\$163.0	\$136.5	\$360.8	\$283.0
Changes in assets and liabilities	(\$40.4)	(\$13.8)	(\$34.6)	\$10.6
Adjusted cash flows from operations	\$122.6	\$122.7	\$326.2	\$293.6
Weighted-average diluted shares outstanding	48.8	40.1	45.7	38.8
Adjusted cash flows per diluted share	\$2.51	\$3.06	\$7.14	\$7.56