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 the company’s 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 effects of recent Delaware Basin acquisitions; estimated future production (including the components of such production), sales, expenses, cash flows, liquidity and balance sheet attributes (including debt to EBITDAX ratios); 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; operational flexibility and ability to revise development plans, either upward or downward; availability of sufficient funding and liquidity for the capital program and sources of that funding; expected net settlements on derivatives for 2017; future exploration, drilling and development activities, including non-operated activity, the number of drilling rigs expected to run and lateral lengths of wells, including the number of rigs expected to run in 2017 in the Delaware Basin; expected 2017 production and timing of turn-in-lines; the evaluation method of customers’ and derivative counterparties’ credit risk; effectiveness of the derivative program in providing a degree of price stability; potential for future impairments; expected expansion of gas processing systems and expected line pressure; compliance with debt covenants; impact of litigation on the results of operations and financial position; that the company does not expect to pay dividends in the foreseeable future; and 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 Asset History

Assets 1969 – West Virginia

1969 - 1999
- Founded in Bridgeport, WV (1969)
- Shallow Upper Devonian drilling partnerships
- Natural gas focused

1977
- Began trading on NASDAQ as PETD
- Stock price: $1.75/share
- Market Cap: $9 MM
- Proved Reserves: 1.4 MMBoe (89% nat gas)

2/8/2017
PDC Energy Asset History

**Assets 1999-forward**

**1999 - 2014**
- Moved headquarters to Denver, CO (2009)
- Asset acquisitions (Wattenberg, Piceance, etc.)

**2010**
- Began trading under new ticker: PDCE
- Shifted focus to liquid-rich drilling

**2014**
- Stock price: $50/share
- Market cap: ~$2 B

2/8/2017
PDC Energy Asset History

Assets 2017

2015 - 2017

- Drove efficiencies through downturn (2015)
- Consolidated acreage position in Wattenberg (NBL trade)
- $1.6 billion Delaware Basin acquisitions
  - 61,500 net acres

2017 (Feb. 1st)

- Stock price: $73/share
- Market Cap: ~$5 B
- Proved Reserves: 341 MMBBoe (58% liquids)
PDC Energy – Company Overview

Core Wattenberg
~96,000 net acres

Core Delaware
~61,500 net acres

Utica Shale
~65,000 net acres

$6.0
Enterprise Value (Billions)(1)

~1.8x
YE17e Debt/EBITDAX(2)

30 - 33
2017e Production (MMBoe)

>40%
2017e Annual Production Growth
(Midpoint)

341
YE16 Proved Reserves (MMBoe)

(1) As of 2/3/17; 65.7 million shares outstanding (2) EBITDAX is adj. EBITDA plus exploration expense, excludes gain/loss sale on assets.
PDC Energy – 2017 Production and Capital Budget

$750mm
2017e Capex Midpoint ($725 - $775mm)

$50-100mm
YE17e Cash Balance(1)

1.8x
YE17e Debt to EBITDAX(1)

37%
2017e Increase in Lateral Feet Drilled

2017e PRODUCTION GUIDANCE

- 30.0 – 33.0 MMBoe
  - 82,200 – 90,400 Boe/d
  - ~97,000 Boe/d Dec. 2017 exit rate
  - 40% production growth over 2016
  - 50% oil production growth

2017e Production Mix
(~66% Liquids)

- OIL 41-45%
- GAS 34-38%
- NGL 19-23%

2017e Drilling Program

<table>
<thead>
<tr>
<th>All numbers approximate</th>
<th>Wattenberg</th>
<th>Delaware</th>
<th>Utica</th>
</tr>
</thead>
<tbody>
<tr>
<td>Capital Expenditures (millions)</td>
<td>$490</td>
<td>$235(2)</td>
<td>$18</td>
</tr>
<tr>
<td>Operated Spuds</td>
<td>145</td>
<td>28</td>
<td>2</td>
</tr>
<tr>
<td>Operated TILs</td>
<td>150</td>
<td>19</td>
<td>2</td>
</tr>
<tr>
<td>Avg. TIL Lateral Length (feet)</td>
<td>6,900</td>
<td>8,600</td>
<td>12,000</td>
</tr>
<tr>
<td>Avg. Working Interest</td>
<td>85%</td>
<td>92%</td>
<td>80%</td>
</tr>
</tbody>
</table>

(1) Guidance based on internal NYMEX price assumptions: ~$51/Bbl oil, $3.30/Mcf Natural Gas, NGL realizations at 25% of NYMEX.
(2) Includes ~$35 million for leasing, seismic and technical studies and ~$15 million in midstream related capital investment.
PDC Energy – Strong Financial Positioning

As of 9/30/16, Pro Forma Delaware Basin Acquisitions

**Leverage and Liquidity**
- YE16e Debt/EBITDAX(1) of ~2.2x
- ~$200 million cash balance
- ~$890 million liquidity

**Debt Maturities**
- $700 million credit facility due May 2020
- $200 million 1.125% convertible notes due September 2021
- $500 million 7.75% senior notes due October 2022
- $400 million 6.125% senior notes due September 2024

---

(1) 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.
Asset Overview – Scalability in Two Top-Tier Basins

Core Wattenberg & Core Delaware Portfolio

• Multiple years of highly economic drilling in Core Wattenberg and Core Delaware
  – Internal rates of return extremely competitive
• Estimated combined net reserve 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\(^{(1)}\)

<table>
<thead>
<tr>
<th></th>
<th>Core Wattenberg – 10-12 Years</th>
<th>Core Delaware – 15-20 Years</th>
</tr>
</thead>
</table>

ESTIMATED POTENTIAL NET RESERVES

<table>
<thead>
<tr>
<th></th>
<th>Core Wattenberg – 550-600 MMBoe</th>
<th>Core Delaware – 550-600 MMBoe</th>
</tr>
</thead>
</table>

NET INVESTMENT CAPITAL

<table>
<thead>
<tr>
<th></th>
<th>Core Wattenberg – ~$5 Billion</th>
<th>Core Delaware – ~$4 Billion</th>
</tr>
</thead>
</table>

(1) Assumes current development plan and spacing assumptions.
Asset Overview – High-Return Portfolio Optionality

- Untapped upside present in both Wattenberg and Delaware assets
- Competition for capital drives innovation and enhanced results
- Allocation of capital split between two top-tier basins, provides portfolio optionality

PDC Portfolio Type Well IRRs(1)

<table>
<thead>
<tr>
<th>Price Deck</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
<th>2020+</th>
</tr>
</thead>
<tbody>
<tr>
<td>NYMEX Oil</td>
<td>$51</td>
<td>$55</td>
<td>$61</td>
<td>$65</td>
</tr>
<tr>
<td>NYMEX Gas</td>
<td>$2.95</td>
<td>$3.50</td>
<td>$3.30</td>
<td>$3.30</td>
</tr>
</tbody>
</table>

(1) Completed well cost (“CWC”) $2.5MM (SRL Watt.); $6.5MM (5,000’ lateral; East & Central Del.) & $9.5MM (10,000’ lateral; Western); Reflects long-term differentials. Excludes lease acquisition and corporate level costs.
Core Wattenberg – Asset Summary

96,000
~ Net Acres

100%
~ Acreage HBP

145/150
2017e Spuds & TILs

7,300’
2017e Avg. Lateral Length (Spud)

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Core Wattenberg – Strategic Acreage Trade

Trade with Noble Energy Closed September 2016

• 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
  – Allows for consolidation of production facilities
Core Wattenberg – Ongoing Enhancement Tests

PDC Acreage

LDS (MRL/Proppant)
- 685 Mboe Middle Core MRL Type Curve
- ~1800 lbs./ft.
- ~1300 lbs./ft.

Cockroft (Tighter Spacing)
- 685 Mboe Middle Core MRL Type Curve
- Cockroft 120 ft. Spacing
- Cockroft 145 ft. Spacing

Loloff Farms (XRL)
- 850 Mboe Middle Core XRL Type Curve
- Loloff Farms Pad

Sater (Slickwater)
- 490 Mboe Middle Core SRL Type Curve
- Traditional Hybrid
- Slickwater
Core Wattenberg – Monobore Drilling Gains

• Current Implementation
  – Monobore drilling saves ~1 day in spud-to-spud times
  – ~$50-100k savings per well
  – 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

<table>
<thead>
<tr>
<th>Design Comparison</th>
<th>Conventional</th>
<th>Monobore</th>
</tr>
</thead>
<tbody>
<tr>
<td>Avg. Drill Times</td>
<td>7 – 9 days</td>
<td>6 – 8 days</td>
</tr>
</tbody>
</table>
### Core Wattenberg – Resilient Returns

#### Type Well IRR Comparison

<table>
<thead>
<tr>
<th>Lateral Type</th>
<th>Lateral Length (feet)</th>
<th>EUR (MBoe)</th>
<th>Capital Cost (MM)</th>
<th>F&amp;D Cost (per Boe)</th>
<th>IRR(2)</th>
<th>PV10(2) (MM)</th>
</tr>
</thead>
<tbody>
<tr>
<td>SRL</td>
<td>4,200</td>
<td>490</td>
<td>$2.5</td>
<td>$6.37</td>
<td>33%</td>
<td>$1.4</td>
</tr>
<tr>
<td>MRL</td>
<td>6,900</td>
<td>685</td>
<td>$3.5</td>
<td>$6.39</td>
<td>37%</td>
<td>$2.4</td>
</tr>
<tr>
<td>XRL</td>
<td>9,500</td>
<td>850</td>
<td>$4.5</td>
<td>$6.61</td>
<td>33%</td>
<td>$2.8</td>
</tr>
</tbody>
</table>

(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.
DELAWARE OVERVIEW
• 61,500 net acres in Reeves (42,050) and Culberson (19,450) Counties, TX

• 32.5 MMBoe proved reserves at YE16; ~68% liquids
  – ~580 MMBoe of estimated net reserves potential (65% liquids) across all acreage

• 785 currently identified locations in Wolfcamp A, B and C zones
  – Primarily 5,000’ laterals
  – Assumes only 4-12 wells per section
  – Industry testing significantly tighter spacing and additional zones

• 93% average working interest
  – ~100% operated; ~30% currently HBP
Delaware Basin – Acreage Overview

- **93%** Average WI
- **100%** Approximate Operated Position
- **785** Currently Identified Locations (Based on only 4-12 total wells per section targeting Wolfcamp A/B/C)
- **15-20** Years of Drilling Inventory
- **~1 MM** Average Boe EURs/Well

PDC Acreage

Off-set operator positions estimated

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Delaware Basin – 2017 Initiatives and Capital Budget

- $185 million D&C budget
  - Spud 28 wells
    - 12 spuds in Eastern
    - 14 spuds in Central
    - 2 spuds in Western
  - TIL 19 wells including 13 XRLs
- $15 million midstream infrastructure
  - Install gas gathering lines
  - Drill water supply well and construct frac pits
  - Add SWD wells and capacity
- $35 million leasing, seismic & tech studies

Budgeted Well Costs (millions)

<table>
<thead>
<tr>
<th>Lateral Length</th>
<th>1-Well Pad</th>
<th>4-Well Pad</th>
</tr>
</thead>
<tbody>
<tr>
<td>1 mile (SRL)</td>
<td>$6.5</td>
<td>$5.8</td>
</tr>
<tr>
<td>1.5 miles (MRL)</td>
<td>$8.0</td>
<td>$7.6</td>
</tr>
<tr>
<td>2 miles (XRL)</td>
<td>$9.5</td>
<td>$9.1</td>
</tr>
</tbody>
</table>

2/8/2017
## Delaware Basin – Highly Productive Acreage Blocks

<table>
<thead>
<tr>
<th>Region</th>
<th>Net Acres</th>
<th>WI</th>
<th>Wolfcamp EURs</th>
<th>Oil Production Range</th>
<th>Gas Production Range</th>
<th>NGLs Production Range</th>
</tr>
</thead>
<tbody>
<tr>
<td>WESTERN</td>
<td>16,000</td>
<td>100%</td>
<td>A: 1,200 MBoe</td>
<td>20 – 50%</td>
<td>30 – 50%</td>
<td>20 – 30%</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>B: 750 MBoe</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>C: 1,400 MBoe</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Inventory: 40 locations</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EASTERN</td>
<td>17,600</td>
<td>91%</td>
<td>A: 1,000 MBoe</td>
<td>50 – 70%</td>
<td>20 – 30%</td>
<td>10 – 20%</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>B: 750 MBoe</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>C: 1,400 MBoe</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Inventory: 410 locations</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>CENTRAL</td>
<td>27,900</td>
<td>87%</td>
<td>A/B: 1,050 MBoe</td>
<td>30 – 50%</td>
<td>30 – 40%</td>
<td>20 – 30%</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>C: 1,400 MBoe</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Inventory: 335 locations</td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

*All EURs and locations based on 5,000’ laterals except Western which are based on 10,000’ laterals*
**Well Spacing & Inventory Summary**

<table>
<thead>
<tr>
<th>Bench</th>
<th>Max ACQ Spacing</th>
<th>Peer Tests</th>
<th>Eastern Inventory (17,600 net acres)</th>
<th>Central Inventory (27,900 net acres)</th>
<th>Western Inventory (17,600 net acres)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Wells/Sec</td>
<td>Wells/Sec</td>
<td>ACQ</td>
<td>Upside</td>
<td>ACQ</td>
</tr>
<tr>
<td>1st Bone Spg/Avalon</td>
<td>-</td>
<td>4 - 12</td>
<td>(XEC, CXO)</td>
<td>200</td>
<td>-</td>
</tr>
<tr>
<td>2nd Bone Spg</td>
<td>-</td>
<td>4 - 6</td>
<td>(CXO)</td>
<td>125</td>
<td>-</td>
</tr>
<tr>
<td>3rd Bone Spg</td>
<td>-</td>
<td>4 - 8</td>
<td>(NBL, CXO)</td>
<td>150</td>
<td>-</td>
</tr>
<tr>
<td>Wolfcamp A</td>
<td>8</td>
<td>8 - 12</td>
<td>(XEC, APC)</td>
<td>260</td>
<td>350</td>
</tr>
<tr>
<td>Wolfcamp B</td>
<td>4</td>
<td>6 - 8</td>
<td>(NBL, EGN)</td>
<td>150</td>
<td>250</td>
</tr>
<tr>
<td>Wolfcamp C</td>
<td>4</td>
<td>6</td>
<td>(EGN)</td>
<td>-</td>
<td>150</td>
</tr>
<tr>
<td>Total</td>
<td>4 - 12</td>
<td>32 - 52</td>
<td></td>
<td>410</td>
<td>1,225</td>
</tr>
</tbody>
</table>

**Acquisition Model**
- 785 currently identified gross locations
- 3 main horizons
- Estimated 580 MMBboe of potential net reserves

**Potential Unrisked Upside Inventory**
- Over 3,500 total potential gross locations
- 6+ potential zones across acreage
- Over 1 Billion Boe of potential net resource
PDC Energy – Strategic Overview

- Top-Tier Growth Profile
- Capital Efficient Drilling Projects in Two Premier Basins
- Financial Discipline
- Technical Initiatives & Operational Enhancements
- Long-Term Focus on Value Creation
Investor Relations

  Mike Edwards, Senior Director Investor Relations
  michael.edwards@pdce.com

  Kyle Sourk, Manager Investor Relations
  kyle.sourk@pdce.com

Corporate Headquarters

  PDC Energy, Inc.
  1775 Sherman Street
  Suite 3000
  Denver, Colorado  80203
  303-860-5800

Website

  www.pdce.com
PDC Energy – Hedge Position Summary

Hedges in place as of December 31, 2016 plus hedges entered prior to January 31, 2017

<table>
<thead>
<tr>
<th></th>
<th>2017</th>
<th></th>
<th>2018</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>~8.5 MMBbls crude oil volumes at weighted average floor price of $49.25/Bbl</td>
<td>38,217 BBtu natural gas volumes at weighted average floor price of $3.30/MMBtu</td>
<td></td>
</tr>
<tr>
<td></td>
<td>~5.2 MMBbls crude oil volumes at weighted average floor price of $50.38/Bbl</td>
<td>46,510 BBtu natural gas volumes at weighted average floor price of $2.83/MMBtu</td>
<td></td>
</tr>
</tbody>
</table>

(1) Natural gas hedged price is at NYMEX and includes any CIG basis swaps.
Core Wattenberg – Midstream Overview

**OIL**

- Multiple takeaway options (refinery, pipeline, trucking and rail)
- Excess takeaway capacity projected for several years
- 2017 oil differential of ~$4.50/Bbl\(^{(1)}\)

**NATURAL GAS**

- Diversified gas takeaway (DCP/Aka-APC)
- DCP current capacity ~800 MMcf/d\(^{(2)}\)
  - + 40 MMcf/d bypass (summer 2017)
  - + 200 MMcf/d plant (year-end 2018)
  - + 200 MMcf/d plant (mid-year 2019)

---

(1) Budget average, includes firm commitment on White Cliffs pipeline; (2) Source: DCP Midstream press release, 1/4/17
Core Wattenberg – Updated 2016 EUR Analysis

Based on Evaluation of Public Production Data

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

<table>
<thead>
<tr>
<th>Area</th>
<th>Industry Average 3-Phase EUR</th>
<th>EUR Variability (P10/P90) Ratio</th>
</tr>
</thead>
<tbody>
<tr>
<td>Inner Core</td>
<td>600 MBoe</td>
<td>2.6</td>
</tr>
<tr>
<td>Middle Core</td>
<td>460 MBoe</td>
<td>2.6</td>
</tr>
<tr>
<td>Outer Core</td>
<td>311 MBoe</td>
<td>3.6</td>
</tr>
<tr>
<td>Non-Core DJ Basin</td>
<td>149 MBoe</td>
<td>10.3</td>
</tr>
</tbody>
</table>

(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.
Eastern Acreage Block: ~17,600 Net Acres

**Wolfcamp A**
- Cumulative BOE per 5,000’ of Lateral
- Cumulative BOE per 5,000’ of Lateral (BOE)
- Eastern - 1,000 MBoe Wolfcamp A Type Curve
- KEYHOLE 34 #1H
- SUGARLOAF 74 #1H
- HANGING H STATE 70 #3H

**Wolfcamp B**
- Cumulative BOE per 5,000’ of Lateral
- Cumulative BOE per 5,000’ of Lateral (BOE)
- Eastern - 750 MBoe Wolfcamp B Type Curve
- TRIANGLE 75 #2H

**Area Highlights**
- ~17,600 net acres
- ~91% WI
- ~69% NRI (76% N/G)

**Oil:** 50 – 70%

**Gas:** 20 – 30%

**NGLs:** 10 – 20%

**Est. 1-Mile EUR:** 1,000 MBoe

**Est. 1-Mile EUR:** 750 MBoe

**Type curve estimates based on industry wells completed since 2014.**
Central Acreage Block: ~27,900 Net Acres

**Wolfcamp A / Wolfcamp B**
- Cumulative BOE per 5,000’ of Lateral
  - Central - 1,050 MBoe Wolfcamp A & B Type Curve
  - Central - Wolfcamp A & B Performance
  - Est. 1-Mile EUR: 1,050 MBoe

**Wolfcamp C**
- Cumulative BOE per 5,000’ of Lateral
  - Central - 1,400 MBoe Wolfcamp C Type Curve
  - Central - Wolfcamp C Performance
  - Est. 1-Mile EUR: 1,400 MBoe

**Area Highlights**
- ~27,900 net acres
- ~87% WI
- ~66% NRI (76% N/G)
- Oil: 30 – 50%
- Gas: 30 – 40%
- NGLs: 20 – 30%

**Capitan - Ava State**
- Wolfcamp A
- 30-day Peak IP: 1,250 Boe/d
- Lateral Length: ~4,200’

**Capitan - Dorothy State**
- Wolfcamp A
- 30-day Peak IP: 1,100 Boe/d
- Lateral Length: ~4,200’

**PDC/EGN – Tisdale**
- Wolfcamp B
- IP30: 1,804 Boe/d
- Lateral Length: 4,300’

**REX – Jolly**
- Wolfcamp A
- IP30: 1,552 Boe/d
- Lateral Length: 7,519’

**EOG – Harrison Ranch**
- Wolfcamp C
- IP24: 1,629 Boe/d
- Lateral Length: 4,500’

**EOG – State Apache**
- Wolfcamp A
- 24-hr IP: 2,659 Boe/d
- Lateral Length: 4,300’

**XEC – Big Timber**
- Wolfcamp A
- IP30: 3,309 Boe/d
- Lateral Length: ~10,000

Type curve estimates based on industry wells completed since 2014.
Western Acreage Block: ~16,000 Net Acres

**Wolfcamp A**
Cumulative BOE per 10,000’ of Lateral

- Western - 1,200 MBoe Wolfcamp A Type Curve
- Western - Wolfcamp A Performance

Est. 2-Mile EUR: 1,200 MBoe

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

**Oil**: 20 – 50%

**Gas**: 30 – 50%

**NGLs**: 20 – 30%

**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

2/8/2017

(1) Excludes midstream related downtime; type curve estimates based on industry wells completed since 2014.
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

>100
Est. Combined 2018 Daily Production (Mboe/d)

40%
Est. Pro Forma Oil Production Mix

<2.5x
Target Debt/EBITDAX\(^{(1)}\)

<table>
<thead>
<tr>
<th>Organic Base Case</th>
<th>Range</th>
<th>Pro Forma Acquisition</th>
<th>Range</th>
</tr>
</thead>
</table>

<table>
<thead>
<tr>
<th>Production (MMBOE)</th>
<th>3-Year CAGR</th>
</tr>
</thead>
<tbody>
<tr>
<td>Stand Alone</td>
<td>20%</td>
</tr>
<tr>
<td>Pro Forma</td>
<td>31%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>Cash Flow ($MM)</th>
<th>$1,200</th>
</tr>
</thead>
<tbody>
<tr>
<td>CAPEX ($MM)</td>
<td>$800</td>
</tr>
<tr>
<td>Debt to EBITDAX(^{(1)})</td>
<td></td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>NYMEX Oil</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>$42</td>
<td>$51</td>
<td>$55</td>
<td>$61</td>
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</table>

<table>
<thead>
<tr>
<th>NYMEX Gas</th>
<th>2016</th>
<th>2017</th>
<th>2018</th>
<th>2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>$2.37</td>
<td>$2.95</td>
<td>$3.50</td>
<td>$3.30</td>
<td></td>
</tr>
</tbody>
</table>

(1) Debt to EBITDAX reflects corporate target and permanent acquisition financing of both debt and equity.
Utica Update

• ~65,000 net acres; ~50% HBP

• ~$27MM capital plan in 2016
  – Neff well: May TIL
    o 10,000’ lateral testing efficiency improvements
    o Best PDC Utica results per lateral foot to-date

  – Mason pad: June TIL
    o 6,000’ lateral testing completion designs from Cole & Dynamite pads
    o Continue to monitor well performance

  – Miley pad: November TIL
    o Well-orientation testing

• Completed well costs of ~$5.5 million for a 6,000’ lateral well
Reconciliation of Non-US GAAP Financial Measures

In millions, except per share data

### Adjusted EBITDA from net income (loss):

<table>
<thead>
<tr>
<th></th>
<th>Three Months Ended Sept 30,</th>
<th>Nine Months Ended Sept 30,</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2016</td>
<td>2015</td>
</tr>
<tr>
<td>Net loss</td>
<td>($23.3)</td>
<td>($41.5)</td>
</tr>
<tr>
<td>(Gain) loss on commodity derivative instruments</td>
<td>($19.4)</td>
<td>($123.5)</td>
</tr>
<tr>
<td>Net settlements on commodity derivative instruments</td>
<td>$47.7</td>
<td>$68.0</td>
</tr>
<tr>
<td>Interest expense, net</td>
<td>$20.1</td>
<td>$10.7</td>
</tr>
<tr>
<td>Income tax provision</td>
<td>($12.0)</td>
<td>($21.2)</td>
</tr>
<tr>
<td>Impairment of properties and equipment</td>
<td>$0.9</td>
<td>$154.0</td>
</tr>
<tr>
<td>Depreciation, depletion, and amortization</td>
<td>$112.9</td>
<td>$81.0</td>
</tr>
<tr>
<td>Accretion of asset retirement obligations</td>
<td>$1.8</td>
<td>$1.6</td>
</tr>
<tr>
<td><strong>Adjusted EBITDA</strong></td>
<td>$128.7</td>
<td>$129.1</td>
</tr>
<tr>
<td>Weighted-average diluted shares outstanding</td>
<td>48.8</td>
<td>40.1</td>
</tr>
<tr>
<td><strong>Adjusted EBITDA per diluted share</strong></td>
<td>$2.64</td>
<td>$3.22</td>
</tr>
</tbody>
</table>

### Adjusted EBITDA from net cash from operations activities:

<table>
<thead>
<tr>
<th></th>
<th>Three Months Ended Sept 30,</th>
<th>Nine Months Ended Sept 30,</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2016</td>
<td>2015</td>
</tr>
<tr>
<td>Net cash from operating activities</td>
<td>$163.0</td>
<td>$136.5</td>
</tr>
<tr>
<td>Interest expense, net</td>
<td>$20.1</td>
<td>$10.7</td>
</tr>
<tr>
<td>Stock-based compensation</td>
<td>($4.1)</td>
<td>($4.8)</td>
</tr>
<tr>
<td>Amortization of debt discount and issuance costs</td>
<td>($9.9)</td>
<td>($1.8)</td>
</tr>
<tr>
<td>Gain on sale of properties and equipment</td>
<td>$0.2</td>
<td>$0.1</td>
</tr>
<tr>
<td>Other</td>
<td>($0.2)</td>
<td>$2.2</td>
</tr>
<tr>
<td>Changes in assets and liabilities</td>
<td>($40.4)</td>
<td>($13.8)</td>
</tr>
<tr>
<td><strong>Adjusted EBITDA</strong></td>
<td>$128.7</td>
<td>$129.1</td>
</tr>
<tr>
<td>Weighted-average diluted shares outstanding</td>
<td>48.8</td>
<td>40.1</td>
</tr>
<tr>
<td><strong>Adjusted EBITDA per diluted share</strong></td>
<td>$2.64</td>
<td>$3.22</td>
</tr>
</tbody>
</table>
### Reconciliation of Non-US GAAP Financial Measures

*In millions, except per share data*

#### Adjusted net income (loss) from net income (loss):

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Net loss</td>
<td>($23.3)</td>
<td>($190.3)</td>
</tr>
<tr>
<td>(Gain) loss on commodity derivative instruments</td>
<td>($19.4)</td>
<td>$62.3</td>
</tr>
<tr>
<td>Net settlements on commodity derivative instruments</td>
<td>$47.7</td>
<td>$167.9</td>
</tr>
<tr>
<td>Tax effect of above adjustments</td>
<td>($10.8)</td>
<td>($87.6)</td>
</tr>
<tr>
<td><strong>Adjusted net loss</strong></td>
<td>($5.8)</td>
<td>($47.7)</td>
</tr>
<tr>
<td>Weighted-average diluted shares outstanding</td>
<td>48.8</td>
<td>45.7</td>
</tr>
<tr>
<td>Adjusted net loss per diluted share</td>
<td>($0.12)</td>
<td>($1.04)</td>
</tr>
</tbody>
</table>

#### Adjusted cash flows from operations from net cash from operating activities:

<table>
<thead>
<tr>
<th></th>
<th></th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td>Net cash from operating activities</td>
<td>$163.0</td>
<td>$360.8</td>
</tr>
<tr>
<td>Changes in assets and liabilities</td>
<td>($40.4)</td>
<td>($34.6)</td>
</tr>
<tr>
<td><strong>Adjusted cash flows from operations</strong></td>
<td><strong>$122.6</strong></td>
<td><strong>$326.2</strong></td>
</tr>
<tr>
<td>Weighted-average diluted shares outstanding</td>
<td>48.8</td>
<td>45.7</td>
</tr>
<tr>
<td>Adjusted cash flows per diluted share</td>
<td>$2.51</td>
<td>$7.14</td>
</tr>
</tbody>
</table>

2/8/2017