Forward Looking Statements

This presentation contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 ("Securities Act"), Section 21E of the Securities Exchange Act of 1934 ("Exchange Act") and the United States ("U.S.") Private Securities Litigation Reform Act of 1995 regarding our business, financial condition, results of operations and prospects. All statements other than statements of historical fact included in and incorporated by reference into this presentations are "forward-looking statements." Words such as expect, anticipate, intend, plan, believe, seek, estimate, schedule and similar expressions or variations of such words are intended to identify forward-looking statements herein. Forward-looking statements include, among other things, statements regarding future: production, costs and cash flows; drilling locations, zones and growth opportunities; commodity prices and differentials; capital expenditures and projects, including the number of rigs employed; management of lease expiration issues; financial ratios and compliance with covenants in our revolving credit facility; impacts of certain accounting and tax changes; midstream capacity and related curtailments; fractionation capacity; impacts of Colorado political matters; ability to meet our volume commitments to midstream providers; ongoing compliance with our consent decree; reclassification of the Denver Metro/North Front Range NAA ozone classification to serious; and timing and adequacy of infrastructure projects of our midstream providers, including the impact of having a new plant come online during the third quarter of 2018.

The above statements are not the exclusive means of identifying forward-looking statements herein. Although forward-looking statements contained in this presentation reflect our good faith judgment, such statements can only be based on facts and factors currently known to us. 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 or accompanying materials, we may use the term "projection" or similar terms or expressions, or indicate that we have "modeled" certain future scenarios. We typically use these terms to indicate our current thoughts on possible outcomes relating to our business or our industry in periods beyond the current fiscal year. Because such statements relate to events or conditions further in the future, they are subject to increased levels of uncertainty.

Further, we urge you to carefully review and consider the cautionary statements and disclosures, specifically those under the heading "Risk Factors," made in the Annual Report on Form 10-K for the year ended December 31, 2017, filed with the U.S. Securities and Exchange Commission ("SEC") on February 27, 2018 and amended on May 1, 2018, and our other filings with the SEC for further information on risks and uncertainties that could affect our business, financial condition, results of operations, and prospects, which are incorporated by this reference as though fully set forth herein. We caution you not to place undue reliance on the forward-looking statements, which speak only as of the date of this report. We undertake 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.

This presentation contains certain non-GAAP financial measures. A reconciliation of each such measure to the most comparable GAAP measure is presented in the Appendix hereto. We use "adjusted cash flows from operations," "adjusted net income (loss)," "adjusted EBITDA," and "adjusted EBITDAX" and "PV-10," non-GAAP financial measures, for internal reporting and providing guidance on future results. These measures are not measures of financial performance under GAAP. We strongly advise investors to review our financial statements and publicly filed reports in their entirety and not rely on any single financial measure. See the Appendix for a reconciliation of these measures to GAAP. Rate of return estimates do not reflect lease acquisition costs or corporate general and administrative expenses. Non-proved estimates of potentially recoverable hydrocarbons and EURs may not correspond to estimates of reserves as defined under SEC rules. Resource estimates and estimates of non-proved reserves include potentially recoverable quantities that are subject to substantially greater risk than proved reserves.

Commonly Used Definitions

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td>Bbl</td>
<td>Barrel</td>
</tr>
<tr>
<td>Boe</td>
<td>Barrel of oil equivalent</td>
</tr>
<tr>
<td>Btu</td>
<td>British thermal unit</td>
</tr>
<tr>
<td>CAGR</td>
<td>Compound Annual Growth Rate</td>
</tr>
<tr>
<td>CWC</td>
<td>Completed well cost</td>
</tr>
<tr>
<td>D&amp;C</td>
<td>Drilling and Completions</td>
</tr>
<tr>
<td>EBITDA</td>
<td>Earnings before interest, taxes, depreciation, amortization and exploration</td>
</tr>
<tr>
<td>EUR</td>
<td>Estimated Ultimate Recovery</td>
</tr>
<tr>
<td>Gross Margin</td>
<td>Oil, gas and NGL sales less LOE, TGP and prod. tax, as a % of oil, gas and NGL sales</td>
</tr>
<tr>
<td>Leverage Ratio</td>
<td>as defined in our revolving credit facility agreement; similar to Debt to EBITDA</td>
</tr>
<tr>
<td>LOE</td>
<td>Lease operating expenses</td>
</tr>
<tr>
<td>MM</td>
<td>Million</td>
</tr>
<tr>
<td>MMcf</td>
<td>Million cubic feet</td>
</tr>
<tr>
<td>SRL/MRL/XRL</td>
<td>Standard-, Mid- and Extended-reach lateral</td>
</tr>
<tr>
<td>SWD</td>
<td>Salt-water disposal</td>
</tr>
<tr>
<td>TGP</td>
<td>Transportation, gathering and processing</td>
</tr>
<tr>
<td>TIL</td>
<td>Turn-in-line</td>
</tr>
</tbody>
</table>

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Primarily due to the pace of ongoing third-party midstream system optimization negatively impacting 2H18 production, PDC anticipates being at the bottom end of the production range, or ~40 MMBoe (1)

Does not include impact of Strategic Acreage Trade with Noble.

Strong Returns on inventory ~1,950 (2)
gross locations in the Core Wattenberg and Delaware basins

Prolific Results expected to drive ~25% production growth in 2018 with free cash flow generation in 4Q18

Corporate Responsibility focused on sustainable operations and the safe and responsible development of our assets

[1] Primarily due to the pace of ongoing third-party midstream system optimization negatively impacting 2H18 production, PDC anticipates being at the bottom end of the production range, or ~40 MMBoe (2) Does not include impact of Strategic Acreage Trade with Noble.
PDC ENERGY – Company Overview

$2.0B
Market Cap\(^{(1)}\)

$3.2B
Enterprise Value\(^{(1)}\)

453
YE17 Proved Reserves\(^{(2)}\)
(MMBoe)

Core Wattenberg
- \(~100,000\) net acres\(^{(3)}\)
- \(~1,500\) identified locations\(^{(3)}\)
- \(351\) MMBoe proved reserves

Delaware Basin
- \(~55,000\) net acres\(^{(4)}\)
- \(~450\) identified locations\(^{(5)}\)
- \(98\) MMBoe proved reserves

\(^{(1)}\) As of 1/2/19; assumes 66 mm shares outstanding; \(^{(2)}\) Included Utica reserves of 4.2 MMBoe; \(^{(3)}\) Niobrara & Codell only. \(^{(4)}\) Anticipate \(~13,000\) net acres (primarily in Western Culberson County) to expire by end of 1Q19, but currently identified inventory is not expected to be materially impacted; \(^{(5)}\) Some locations subject to higher degree of uncertainty as they are based on downspacing tests the Company is currently in process of testing or has not yet tested.
• Proven track record of value-added growth
  – 35+% 3-year production CAGR

• Remain focused on balance sheet strength
  – ~40% decrease in debt per flowing Boe since 2016 Delaware Basin acquisition
  – YE18e leverage ratio of 1.4x
• Robust inventory of 10-15 years at current development pace
• Entire portfolio delivers strong economic results
  - Weighted-average portfolio of MRL equivalents delivers F&D costs of < $8/Boe and IRRs of ~90%(1)
• XRL development further strengthens expected IRRs & NPVs
  - Early-stage development in the Delaware

Average NPV10(1) per well by Area (MRL Equivalent)

- Block 4: $12.6, IRR > 75%
- North Central: $6.6, IRR > 25%
- Kersey: $5.0, IRR > 100%
- Prairie: $3.9, IRR > 90%
- Plains: $3.1, IRR > 60%

(1) Economics assume current basin differentials curve applied to NYMEX forecast of approximately $65/Bbl and $2.75/Mcf for 2018 and 2019; $60/Bbl and $2.75/Mcf in 2020+; excludes lease acquisition and corporate level costs. Target MRL CWC approximately ~$4.0 million in Wattenberg and ~$12.5 million in Delaware; (2) Approximately 175 Wattenberg and 50 Delaware MRL equivalent locations.
**FINANCIAL GUIDANCE – Updated Full-Year Guidance**

**2018 Guidance**

- **Production**: 40 – 42 MMBoe
- **Capital Investments**: $950 - $985MM

**Price Realizations (% NYMEX) (ex. TGP)**

- **Oil**: 91 – 95%
- **Gas**: 55 – 60%
- **NGL**: 30 – 35%

**LOE/Boe**

<table>
<thead>
<tr>
<th>Year</th>
<th>LOE/Boe</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>$-</td>
</tr>
<tr>
<td>2016</td>
<td>$1.00</td>
</tr>
<tr>
<td>2017</td>
<td>$2.00</td>
</tr>
<tr>
<td>2018</td>
<td>$3.00 - $3.15</td>
</tr>
</tbody>
</table>

**G&A/Boe**

<table>
<thead>
<tr>
<th>Year</th>
<th>G&amp;A/Boe</th>
</tr>
</thead>
<tbody>
<tr>
<td>2015</td>
<td>$-</td>
</tr>
<tr>
<td>2016</td>
<td>$0.50</td>
</tr>
<tr>
<td>2017</td>
<td>$1.00</td>
</tr>
<tr>
<td>2018</td>
<td>$3.40 - $3.70</td>
</tr>
</tbody>
</table>

**Commodity Mix**

- **Oil**: 42-45%
- **NGLs**: 32-35%
- **Natural Gas**: 19-22%

**Jan. 2019**

(1) Primarily due to the pace of ongoing third-party midstream system optimization negatively impacting 2H18 production, PDC anticipates being at the bottom end of the production range, or approximately 40 MMBoe, and at or slightly above the top end of the per Boe cost ranges. (2) G&A per Boe excludes $8 million of legal-related costs incurred in 3Q18.
FINANCIAL STRENGTH – Balance Sheet, Leverage and Liquidity

As of September 30, 2018

Leverage and Liquidity

• Leverage ratio of 1.6x
• ~$75 million drawn on revolver (9/30/18)
• October 2018 – upsized commitment level on revolving credit facility to $1.3 billion from $700 million
  − Pro forma liquidity of $1.23 billion
• Anticipate delivering free cash flow in 4Q18

Hedge Portfolio

• ~60% of 4Q18e oil production hedged at ~$51/Bbl\(^{(1)}\)
• 11.0 MMBbls 2019 oil hedged at ~$55/Bbl\(^{(1)}\)
• 8.6 MMBbls 2020 oil hedged at ~$60/Bbl\(^{(1)}\)
• ~70% of 4Q18e gas production hedged at ~$2.95/MMBtu\(^{(1)}\)

(1) Assumes weighted-average floor prices; (2) Pro forma October 2018 commitment level increase

Debt Maturity Schedule (millions)

- Revolver\(^{(2)}\)
- 6.125% Senior Notes
- 5.75% Senior Notes
- 1.125% Convertible Notes
2019 Considerations

- Expect to have ~200 approved permits and ~100 DUCs at YE18
- Anticipate Plant 11 providing relief to core DJ acreage (Kersey/Plains) in 2H19
- Rig count in one or both basins could change as a result of November 2018 election
- Assume sufficient NGL takeaway and fractionation space for PDC volumes through third-party providers

2020 Considerations

- Capital allocation in both basins dependent on CO political landscape
- Key factors: pricing, differentials, marketing/midstream, service costs, downspaced well performance, etc.

Steady-State 6 Rig Scenario (1)

<table>
<thead>
<tr>
<th>2017</th>
<th>2018e</th>
<th>2019e</th>
<th>2020e</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production (MMBoe)</td>
<td>~30(2)</td>
<td>25 – 35%</td>
<td>15 – 25%</td>
</tr>
<tr>
<td>Outspend/FCF (MM)</td>
<td>($125 - 150)</td>
<td>$100 - $200</td>
<td>$200 - $300</td>
</tr>
<tr>
<td>Cash Flow Yield(2)</td>
<td>(14%)</td>
<td>10 - 20%</td>
<td>20 - 25%</td>
</tr>
<tr>
<td>NYMEX Prices ($/Bbl / $/Mcf)</td>
<td>~$70/$3.00(3)</td>
<td>$65/$2.75</td>
<td>$60/$2.75</td>
</tr>
</tbody>
</table>

3 Rigs in WB and DE

- YE Leverage Ratio: ~1.4x → ~1.0x → ~0.8x
- Capital Investment (MM): $950 - $985 → $950 - $1,050 → $1,000 - $1,200
- Production (MMBoe/% growth): ~40(2) → 25 – 35% → 15 – 25%
- Outspend)/FCF (MM): ($125 - 150) → $100 - $200 → $200 - $300
- Cash Flow Yield(2): (14%) → 10 - 20% → 20 - 25%
- NYMEX Prices ($/Bbl / $/Mcf): ~$70/$3.00(3) → $65/$2.75 → $60/$2.75

(1) Does not reflect Strategic Acreage Trade with Noble. (2) Midpoint of cash flow deficit/free cash flow divided by midpoint of total capital investment; (2) Anticipate being at the bottom end of the production range of 40-42 MMBoe; (3) 4Q18 internal pricing.
CORE WATTENBERG – Prolific Asset in Development Mode

100,000
~Net Acres(1)

1,500
~Horizontal Locations(2)

351
YE17 Proved Reserves (MMBoe)

3Q18 Results
83,670 Boe/d
43 Spuds
22 TILs
$3.01 LOE/Boe

(1) Niobrara and Codell only; (2) Average lateral length of ~6,300 feet.
Acreage Consolidation Strengthens Inventory

- Strategic acreage trade further consolidates Wattenberg position and reduces surface impact

- Added ~70 XRL and ~20 MRL locations to high-value Kersey inventory

- Increased value through longer-laterals and higher working interests

Acreage Trade Inventory Breakdown

Pre-Trade (~550 Locations)  Post-Trade (~360 Locations)

- ~2.6MM Net Lat. Ft.
- ~2.7MM Net Lat. Ft.

Net Acres IN: ~12,300  Net Acres OUT: ~12,900

WI\(^{(1)}\) increased to 87% from 74%

(1) Working interest increase applicable to traded acres only
CORE WATTENBERG – Safely Developing Rural Acreage in Weld County

- PDC has operated in the Wattenberg Field of the DJ Basin for almost 20 years
  - Field office of ~250 employees located in Evans

- Consolidated acreage position minimizes surface usage

- Extensive history of positive working relationships with surrounding communities, regulators and elected officials
  - Support multiple community organizations through year-round charitable giving and volunteerism

- ~100% of PDC net acreage in rural Weld County
  - County voted 75% No on Proposition 112

- ~5% of gross acreage located within municipal boundaries
  - Anticipate ~100% can be reached through long-lateral development from outside municipal boundary
DCP Midstream\textsuperscript{(1)} (~75% of PDC 2018e gas volumes)

- Plant 10 (Mewbourne 3):
  - In-service August 1, 2018
  - Increased system throughput 200 MMcf/d or ~25%

- Plant 11 (O’Connor 2):
  - 300 MMcf/d (including bypass)
  - Expected start-up in 2Q19

- Plant 12 (Big Horn):
  - Up to 1 Bcf/d (including bypass)
  - Expected start-up in 2020

Aka Energy (~25% of PDC 2018e gas volumes)

- Recently expanded processing capacity to ~40 MMcf/d
- Additional offloads to WES system

Other DJ Basin Anticipated Expansions

- Rimrock, Discovery, Western Gas, Outrigger expected to benefit entire basin (~1 Bcf/d additional capacity)

Wattenberg Volumes

- Steady volume growth with DCP Plant 10 start-up
- Pace of DCP system optimization, including planned/unplanned downtimes, factored into updated FY18 guidance
- Consistent run-time benefits core acreage line pressures and PDC volumes

\(\text{(1) Source: DCP Midstream press release dated November 5, 2018}\)
DELAWARE BASIN – Primary Focus in Two Oil-Rich Areas

55,000
~Net Acres(1)

450
~Block 4 & North Central MRL Equivalent Locations(2)

98
YE17 Proved Reserves (MMBoe)

3Q18 Results
26,110 Boe/d
8 Spuds
10 TILs
$4.09 LOE/Boe

(1) Anticipate ~13,000 net acres (primarily in Western Culberson County) to expire by end of 1Q19, but currently identified inventory is not expected to be materially impacted; (2) Average lateral length of ~7,500 feet. Some locations subject to higher degree of uncertainty as they are based on downsizing tests the Company is currently in process of testing or has not yet tested.
DELAWARE BASIN – Focused on Continued Execution

- Anticipate 2018 capital investments of $430 - $450MM
  - Nine months investment of ~$375 million
  - ~80% allocated to spud and TIL 25 – 30 operated wells
  - ~15% planned for midstream infrastructure investments
  - ~5% for leasing, non-op and technical studies

- Drilling and completion execution delivering strong sequential production growth
  - 22 spuds and 22 TILs through nine months

- Focus on water mgmt. helps deliver low-cost operations
  - 2018 LOE expected to be between $3.75 - $4.25/Boe
  - Initial water recycling tests planned mid-year

- Initial Block 4 Bone Spring test spud in 4Q18
• Six WCA wells (12 wells/section eq.) showing minimal signs of communication through choke mgmt. tests (~75% oil)

• Performance and pressure characteristics consistent with low GOR area of Block 4

• Ongoing technical analysis valuable for future completion designs and downspacing projects

• WCC well performance below internal expectations

2019 Initiatives:
Bone Spring test, stack spacing test in WCA and WCB, WCC test
• 2018 development plan successful step in delineated North Central Focus Area
  - 13 spuds and 10 TILs throughout position

• Eight YTD 2018 TILs in North Central area
  - Average 30-day peak IP >200 Boe/d per 1,000’
  - ~50% oil

• 2018 TIL program complete
  - Rabbit Ears TIL’d in 3Q18
  - Two Sunnyside wells TIL’d in October

• North Central compression increased in 3Q18
  - Working on permanent expansions to both compression and pipeline capacity in 4Q18
**Oil – Downstream Marketing**

- Gulf Coast 5.5 year firm sales agreement effective in June 2018
  - International export-market pricing
  - Anticipate competitive netback pricing relative to Mid-Cush through entire contract term
- Near-term impact (2H18 – 2019)
  - Covers ~85% of projected Delaware volumes with remaining ~15% sold at Midland
  - Project all-in Delaware realizations of 88-92% NYMEX (Third Quarter 2018 = ~94% NYMEX)

**Gas – Processing & Marketing**

- 100% of current Eastern volumes have firm takeaway:
  - Firm transport to Waha with associated firm sales agreements (indexed to Gulf Coast prices)
  - Contracts ramping to total of ~75,000 MMBtu/d
- N. Central volumes sold at wellhead to ETC and marketed on ETC-owned assets (Waha)
Potential Delaware Midstream Asset Monetization

- Process ongoing led by Jefferies

- Evaluating option to keep or sell any or all of PDC’s midstream assets, including:
  - Gas gathering and future gas processing
  - Oil gathering and infrastructure
  - Water gathering, disposal and recycling system
  - All midstream infrastructure related to SWD wells

- Anticipated cumulative capital investment through YE18 estimated at ~$150 million

- Targeting YE18 or 1Q19 decision point
PDC ENERGY – Strategic Overview

**Strong Returns** on inventory ~1,950\(^{(2)}\) gross locations in the Core Wattenberg and Delaware basins

**Prolific Results** expected to drive ~25% production growth in 2018 with free cash flow generation in 4Q18

**Corporate Responsibility** focused on sustainable operations and the safe and responsible development of our assets

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  kyle.sourk@pdce.com

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  Suite 3000
  Denver, Colorado 80203
  303-860-5800

Website
  www.pdce.com
• Wattenberg 3Q production beginning to unbundle despite only modest line pressure improvements
  – DCP Plant 10 expansion and PDC system allocations consistent with modeling and messaging
  – Aka Energy provides material processing and offloads

• Strong sequential growth expected in 4Q18
  – December exit rate of ~130,000 Boe/d

• Wattenberg LOE projected to decline as production volumes increase
  – Line pressures remain elevated heading into shoulder season and winter

• Delaware TILs in late 3Q expected to lead to strong 4Q18 growth

![Production Graph](image)

![LOE Graph](image)

Jan. 2019
• Plan to invest $520 - $535 million in 2018
  – 9 months: investment of ~$405 million

• Expect to spud 150 – 165 wells and TIL 145 – 160 wells in 2018
  – 9 months: 121 spuds and 99 TILs

• Plan to operate three rigs and one completion crew\(^{(1)}\)
  – Majority of focus in prolific Kersey Area

• Steady growth expected in 4Q18 as DCP system operates closer to nameplate capacity

• Focus on maintaining low cost structure
  – Anticipate 2018e LOE/Boe of $2.75 - $3.00

---

(1) Second crew completed one pad in 2Q18; (2) Reflects approximate lateral feet completed utilizing new ‘heel and toe’ method. May not apply to all spuds/TILs.
• Modified completion design enhances ability to access additional resource
  - Completing through the bend and drilling to edge of lease boundary enable additional ~1,000’ of completed lateral per well
  - Incremental capital of ~$250k per well
  - ~10% additional stages per well expected to be completed in 2018

  Example: Prior design – 10 well pad of XRLs = ~500 total stages
  New design – 10 well pad of XRLs = ~550 total stages (one “extra” well)

• Increased drilling efficiencies lead to improved spud-to-spud times
  - 5/7/9 days for SRL/MRL/XRLs (down from 6/8/10)

~1,000’ of additional completed interval (5 extra stages)
(Wattenberg D&C well costs modified to ~$3 to $5MM depending on lateral length)
Hedge Position

Hedges in Place as of 9/30/18, plus Hedges Entered into Prior to 11/1/18

**CIG Basis Swaps:**
- Oct – Dec 2018: 9,806 BBtu at ($0.42) off NYMEX
- Jan – Dec 2019: 11,924 BBtu at ($0.83) off NYMEX

**Waha Basis Swaps:**
- Oct– Dec 2018: 1,713 BBtu at ($0.50) off NYMEX

**Propane Hedges:**
- Oct– Dec 2018: 7.0 million gallons at $0.81/gallon

---

**CRUDE OIL**

<table>
<thead>
<tr>
<th>Volumes (MMBbls)</th>
<th>Oct- Dec 2018</th>
<th>2019</th>
<th>2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>Collar</td>
<td>0.5</td>
<td>2.6</td>
<td>3.6</td>
</tr>
<tr>
<td>Swap</td>
<td>3.0</td>
<td>8.4</td>
<td>5.0</td>
</tr>
<tr>
<td>Total Crude Oil Hedged</td>
<td>3.5</td>
<td>11.0</td>
<td>8.6</td>
</tr>
</tbody>
</table>

**Crude Oil Price ($/Bbl)**
- Floor: $45.59, $56.54, $55.00
- Ceilings: $56.82, $68.13, $71.68
- NYMEX Swap: $52.23, $53.86, $62.07
- Weighted Average Price (floor): $51.23, $54.50, $59.11

Mid-Cush Basis Swaps: Oct – Dec 2018: 182,000 Bbls at ($0.10) off NYMEX
CMA Roll Basis Swaps: Oct – Dec 2018: 1.5 MMBbls at $0.14 of NYMEX

---

**NATURAL GAS**

<table>
<thead>
<tr>
<th>Volumes (BBtu)</th>
<th>Oct- Dec 2018</th>
<th>2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>Collar</td>
<td>120</td>
<td>-</td>
</tr>
<tr>
<td>Swap</td>
<td>14,145</td>
<td>16,004</td>
</tr>
<tr>
<td>Total Natural Gas Hedged</td>
<td>14,265</td>
<td>16,004</td>
</tr>
</tbody>
</table>

**Natural Gas Price ($/Mmbtu)**
- Floor: $3.00, $0.00
- Ceiling: $3.90, $0.00
- NYMEX Swap: $2.93, $2.83
- Weighted Average Price (floor): $2.93, $2.83

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**Oil Volumes Hedged**

**Gas Volumes Hedged**
## Reconciliation of Non-U.S. GAAP Financial Measures

### Adjusted EBITDAX

<table>
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<th>Three Months Ended September 30</th>
<th>Nine Months Ended September 30</th>
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</thead>
<tbody>
<tr>
<td></td>
<td>2018</td>
<td>2017</td>
</tr>
<tr>
<td><strong>Net loss to adjusted EBITDAX:</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net loss</td>
<td>$ (3.4)</td>
<td>$(292.5) $</td>
</tr>
<tr>
<td>(Gain) loss on commodity derivative instruments</td>
<td>94.4</td>
<td>52.2</td>
</tr>
<tr>
<td>Net settlements on commodity derivative instruments</td>
<td>(48.1)</td>
<td>9.6</td>
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<tr>
<td>Non-cash stock-based compensation</td>
<td>5.6</td>
<td>4.8</td>
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<tr>
<td>Interest expense, net</td>
<td>17.4</td>
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<td>Income tax expense (benefit)</td>
<td>(3.9)</td>
<td>(122.4)</td>
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<tr>
<td>Impairment of properties and equipment</td>
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<td>252.7</td>
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<tr>
<td>Impairment of goodwill</td>
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<td>Exploration, geologic and geophysical expense</td>
<td>1.0</td>
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<td>Depreciation, depletion and amortization</td>
<td>147.5</td>
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<tr>
<td>Accretion of asset retirement obligations</td>
<td>1.2</td>
<td>1.5</td>
</tr>
<tr>
<td><strong>Adjusted EBITDAX</strong></td>
<td>$ 213.2</td>
<td>$ 166.9</td>
</tr>
</tbody>
</table>

### Cash from operating activities to adjusted EBITDAX:

|                          |      |        |      |                |
|--------------------------|------|--------|------|                |
| Net cash from operating activities | $ 197.0 | $ 148.2 | $ 577.8 | $ 420.7 |
| Interest expense, net    | 17.4 | 18.8   | 52.2 | 56.9           |
| Amortization of debt discount and issuance costs | (3.1) | (3.2) | (9.5) | (9.6) |
| Gain (loss) on sale of properties and equipment | (2.1) | 0.1    | (3.2) | 0.8            |
| Exploration, geologic and geophysical expense | 1.0   | 41.9   | 4.6  | 43.9           |
| Exploratory dry hole costs | —    | (41.2) | —    | (41.2)         |
| Other                    | (1.1) | (0.4)  | (1.5) | 39.2           |
| Changes in assets and liabilities | 4.1   | 2.7    | (2.5) | (13.1)         |
| **Adjusted EBITDAX**     | $ 213.2 | $ 166.9 | $ 617.9 | $ 497.6 |
### Adjusted Cash Flows from Operations

<table>
<thead>
<tr>
<th></th>
<th>Three Months Ended September 30</th>
<th>Nine Months Ended September 30</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2018</td>
<td>2017</td>
</tr>
<tr>
<td>Adjusted cash flows from operations:</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net cash from operating activities</td>
<td>$197.0</td>
<td>$148.2</td>
</tr>
<tr>
<td>Changes in assets and liabilities</td>
<td>4.1</td>
<td>2.7</td>
</tr>
<tr>
<td>Adjusted cash flows from operations</td>
<td>$201.1</td>
<td>$150.9</td>
</tr>
</tbody>
</table>

### Adjusted Net Income (Loss)

<table>
<thead>
<tr>
<th></th>
<th>Three Months Ended September 30</th>
<th>Nine Months Ended September 30</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2018</td>
<td>2017</td>
</tr>
<tr>
<td>Adjusted net income (loss):</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net loss</td>
<td>$ (3.4)</td>
<td>$(292.5)</td>
</tr>
<tr>
<td>(Gain) loss on commodity derivative instruments</td>
<td>94.4</td>
<td>52.2</td>
</tr>
<tr>
<td>Net settlements on commodity derivative instruments</td>
<td>(48.1)</td>
<td>9.6</td>
</tr>
<tr>
<td>Tax effect of above adjustments</td>
<td>(11.1)</td>
<td>(23.2)</td>
</tr>
<tr>
<td>Adjusted net income (loss)</td>
<td>$ 31.8</td>
<td>$(253.9)</td>
</tr>
<tr>
<td>Weighted-average diluted shares outstanding</td>
<td>66.1</td>
<td>65.9</td>
</tr>
<tr>
<td>Adjusted diluted earnings per share</td>
<td>$0.48</td>
<td>$(3.85)</td>
</tr>
</tbody>
</table>