Focused Execution on 2019 Objectives

- Deliver the synergies identified in our Newfield acquisition
  - Target: $125 million in annualized G&A savings
    - Annualized G&A reductions now estimated at $150 million
  - Target: reduce STACK well cost by $1 million
    - Achieved $1 million/well reduction; driving strong returns
    - Significant reduction in D&C cycle times
    - Additional cost reductions identified

- Generate free cash flow\(^\text{†}\) and return capital to shareholders
  - 2019 capital guidance unchanged; higher oil prices YTD increase estimates for free cash flow\(^\text{†}\)
  - $1.25B share buyback program underway
    - YTD purchases; ~91 million shares* at an average price of $7.19 per share
  - 25% increase to dividend in Q1 2019

- 15% YOY proforma liquids growth from the Permian, Anadarko and Montney
  - On track to meet full year guidance

- Deliver Encana’s 6\(^{\text{th}}\) consecutive “safest year ever”

---

\(^*\)Total repurchased as of April 29, 2019
\(^\text{†}\) Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures see the Company's website.
## Significant Momentum

### Strong Financial and Operational Performance

<table>
<thead>
<tr>
<th>Results and Guidance</th>
<th>Q1 2019 Reportable</th>
<th>Q1 2019 Proforma (1)</th>
<th>Expected Q2 – Q4 Run Rate</th>
<th>Full Year Reportable</th>
<th>Full Year Proforma</th>
</tr>
</thead>
<tbody>
<tr>
<td>CAPITAL INVESTMENT ($ MILLION)</td>
<td>736</td>
<td>913</td>
<td>500 – 800</td>
<td>2,500 – 2,700</td>
<td>2,700 – 2,900</td>
</tr>
<tr>
<td>TOTAL LIQUIDS (MBLBS/d)</td>
<td>231</td>
<td>293</td>
<td>300 - 320</td>
<td>290 – 310</td>
<td>300 – 320</td>
</tr>
<tr>
<td>NATURAL GAS (MMCF/d)</td>
<td>1,421</td>
<td>1,644</td>
<td>1,600 – 1,700</td>
<td>1,500 – 1,600</td>
<td>1,550 – 1,650</td>
</tr>
<tr>
<td>TOTAL PRODUCTION (MBOE/d)</td>
<td>468</td>
<td>567</td>
<td>585 – 600</td>
<td>540 – 580</td>
<td>560 – 600</td>
</tr>
<tr>
<td>TOTAL COSTS PER BOE (2)</td>
<td>13.44</td>
<td>n/a</td>
<td>&lt;13.00</td>
<td>12.75 – 13.25</td>
<td>12.75 – 13.25</td>
</tr>
</tbody>
</table>

(1) Q1 2019 proforma includes Encana and Newfield upstream capital and operations prior to the acquisition close February 13, 2019.
(2) Excludes the impact of long-term incentive costs and restructuring costs. BOW office lease costs are included in Administrative.
(3) Includes financial basis hedges.
† Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures see the Company's website.

- Capital investment and production on track
  - Front-half weighted capital program
- Q1 non-GAAP cash flow†, excluding acquisition & restructuring costs, totaled $566 MM ($0.46/sh)
  - Acquisition and restructuring costs of $144 MM reduce quarterly non-GAAP cash flow† to $422 MM ($0.35/sh)
- Improved G&A outlook
  - Quarterly run rate of ~$75 MM
- Market diversification strategy added ~$1.60/BOE to non-GAAP cash flow margin†
  - Permian oil realized price³ ~98% of WTI
  - Canadian gas realized price³ ~90% of NYMEX
**Execution Rapidly Improving Anadarko Returns**

**THE ENCANA ADVANTAGE**

- **Performance-driven project management at the wellsite**

- **Multiple records set during completions**
  - Single day record of 115,000 bbls pumped by one frac crew
  - Exceeded 18 hours a day pump time, consistent with Encana Permian

- **Self-sourced sand and chemicals improve reliability and lower costs**

- **Increased pad dimension accommodates drive-through access to reduce wait times and improve safety**

- **PropX sand system reduces costs, ensures supply**

- **Utilizing dual-lay flat to increase fluid to and from location**

- **Significant efficiency improvements**
  - Nearly doubled stages pumped per day
  - 41% decrease in non-productive time
Anadarko

**Setting New Milestones**

- **Achieved targeted $1 MM/well cost reduction in Q1**
  - Achieved primarily from completions
    - Improved cycle time through higher pump rates
  - Supply chain management
    - Self-sourcing sand and chemicals
    - Unbundled services
    - Levered multi-basin exposure to renegotiate contracts
- **First cube development spud in April**
  - Multiple cube results expected in 2H 2019
- **Further cost reductions identified**
  - Additional drilling and completion efficiencies
  - Executing cube development at scale

<table>
<thead>
<tr>
<th>Pad Size</th>
<th>Frac time Q4 2018</th>
<th>Frac time Q1 2019</th>
<th>% Improvement</th>
</tr>
</thead>
<tbody>
<tr>
<td>3-Well Pad</td>
<td>32 days</td>
<td>18 days</td>
<td>44%</td>
</tr>
<tr>
<td>2-Well Pad</td>
<td>25 days</td>
<td>13 days</td>
<td>48%</td>
</tr>
</tbody>
</table>

*Normalized to 10,000' lateral length*
REPEATABLE WELL PERFORMANCE

Anadarko

• 31 net STACK wells on-stream in Q1\(^{(1)}\)
  o Wells continue to meet or exceed 1.3 MMBOE type curve
  o Includes 49 gross operated STACK wells at 63% liquids

• Q1 proforma production of 145 MBOE/d

• Consistent well results and lower costs driving strong returns
  o Anadarko returns competitive with Permian and Montney

* Normalized to 10,000’ lateral length, includes 49 gross wells
(1) On stream wells are proforma
Permian

- **33 net wells on-stream in Q1**
  - Consistent well performance across all counties

- **Q1 production of 91 MBOE/d**
  - 3.2 MBOE/d shut-in due to third party midstream outages
    - 1.9 Mmbls/d of NGLs and 8 MMcf/d of natural gas

- **~98 MBOE/d in April**
  - On track to meet full year 2019 expectations

- **Leading Permian Basin operator**
  - Best in class cycle time performance
  - Growing production above ~100 MBOE/d with just 4 rigs

* Source: Drilling Info, Inc. Includes all Midland Basin wells on-stream January 1, 2018 to March 2019. Peers include CPE, CVX, CXO, Endeavor, FANG, LPI, OXY, PE, PXD, QEP, SM, and XOM
** Normalized to 8,500' lateral length, includes 33 gross wells
Montney

- 15 net wells on-stream in Q1
  - On track for 70 – 80 net wells in 2019

- Q1 production of 207 MBOE/d
  - 4.3 MBOE/d shut-in due to midstream curtailments
    - 1.1 Mbbls/d of liquids and 19 MMcf/d of gas

- Q1 program exceeding type curve expectations
  - Tighter clusters
  - Optimized well spacing
  - Increased frac intensity

- Continued cycle time improvement
  - Average well on-stream in under 80 days
  - Scheduling optimization and concurrent operations

- Low well costs of ~$4.3 MM and attractive royalty regime drive competitive returns

* Normalized to 7,900' lateral length, includes 22 gross wells
Our 2019 Focus

YTD Accomplishments

• Rapid integration of Newfield Exploration
• Achieved targeted well cost reduction of $1MM in Anadarko
• Increased projected G&A savings to >$150 MM
• Returning capital to shareholders
  o Executed buyback of ~91 million shares* at an average price of $7.19 per share
  o Increased dividend by 25%**
• Spud first cube development in Anadarko

Upcoming Milestones

• Further reductions in Anadarko well costs
• Demonstrate repeatable cube development results in Anadarko
• Complete share buyback program
• Maintain capital discipline
  o Deliver on production and capital outlooks
  o Combined 15% annualized liquids production growth in Permian, Anadarko, and Montney
• Generate free cash flowȚ (2nd year in a row)
  o As cash flowȚ grows, build cash on balance sheet

* Total repurchased as of April 29, 2019.
** Declaration and payment of future dividends is subject to Board approval.
Ț Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures see the Company's website.
# A Premier E&P

<table>
<thead>
<tr>
<th><strong>Financial Strength</strong></th>
<th>Investment grade profile</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Return of Capital</strong></td>
<td>$1.25 billion share buyback and 25% increase in annual dividend*</td>
</tr>
<tr>
<td><strong>Sustainable Free Cash Flow</strong></td>
<td>Unique position as generator of sustainable free cash flow in industry</td>
</tr>
<tr>
<td><strong>Capital Discipline</strong></td>
<td>Generating free cash flow &amp; growth with significantly less capital</td>
</tr>
<tr>
<td><strong>Focus on High-Returns</strong></td>
<td>Multi-year track record of improving economics via operational &amp; financial execution</td>
</tr>
<tr>
<td><strong>Multi-Basin Portfolio with Scale</strong></td>
<td>300 - 320 Mmbls/d** proforma liquids with ~75% from Permian, Anadarko and Montney</td>
</tr>
</tbody>
</table>

*T Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures see the Company’s website

*$1.25 billion share buyback for up to 149.4 million shares, 10% of Encana’s float as at February 27, 2019. Declaration and payment of future dividends is subject to Board approval.

**Full year proforma volumes includes legacy Newfield activity from January 1 to February 13, 2019.
FOCUSED ON EXECUTION

Strong Q1 Financial Results

• **Strong execution on return of capital**(1) to shareholders
  - Buyback now 61% complete
    - Q1 share buyback of 55.9 MM shares with an additional repurchase of 35.1 MM shares to April 29, total of ~61% of buyback complete at $7.19 per share
  - Dividend increased 25% effective in Q1 2019

• **Integration and re-organization quickly executed**
  - Q1 results include restructuring and acquisition costs totaling $144 MM

• **Strong underlying financial results**
  - Q1 non-GAAP cash flow(²), excluding acquisition & restructuring costs, totaled $566 MM ($0.46/sh)
    - Acquisition and restructuring reduce quarterly non-GAAP cash flow(²) to $422 MM ($0.35/sh)

<table>
<thead>
<tr>
<th>Q1 2019</th>
<th>$ Millions</th>
<th>$ Per Share</th>
</tr>
</thead>
<tbody>
<tr>
<td>NET EARNINGS</td>
<td>(245)</td>
<td>$(0.20)</td>
</tr>
<tr>
<td>NON-GAAP OPERATING EARNINGS(²)</td>
<td>165</td>
<td>$0.14</td>
</tr>
<tr>
<td>CASH FROM OPERATING ACTIVITIES</td>
<td>529</td>
<td>n/a</td>
</tr>
<tr>
<td>NON-GAAP CASH FLOW(²)</td>
<td>422</td>
<td>$0.35</td>
</tr>
<tr>
<td>CAPITAL INVESTMENT</td>
<td>736</td>
<td>n/a</td>
</tr>
<tr>
<td>SHARE BUYBACK ($MILLIONS / MILLIONS OF SHARES)</td>
<td>$400 / 55.9</td>
<td></td>
</tr>
<tr>
<td>WEIGHTED AVERAGE SHARES – DILUTED (MILLIONS)</td>
<td>1,221</td>
<td></td>
</tr>
<tr>
<td>SHARES O/S AT MARCH 31, 2019 (MILLIONS)</td>
<td>1,440</td>
<td></td>
</tr>
</tbody>
</table>

(1) $1.25 billion share buyback for up to 149.4 million shares, 10% of Encana’s float as at February 27, 2019. Declaration and payment of future dividends is subject to Board approval.

(²) Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures please see the Company’s website.
## Disciplined Approach

### Priority #1 - Financial Strength
Manage leverage at mid-cycle prices to ~1.5x net debt to adjusted EBITDA\(^\text{†}\)
Maintain strong liquidity
Investment grade credit ratings

### Priority #2 – Dividends*
Sustain current dividend

### Priority #3 - Sustain Business
Maintain cash flow\(^\text{†}\) and liquids production in core areas

### Priority #4 – Dividend Growth
Dividend increase as sustainable free cash flow\(^\text{†}\) grows

### Priority #5 – Excess Free Cash Flow\(^\text{†}\)
Opportunistic share buybacks
Deleverage balance sheet
Reduce debt
Growth investment that generates strong full-cycle returns and expands free cash flow\(^\text{†}\)

*Declaration and payment of future dividends subject to board approval
\(^\text{†}\) Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures see the Company's website
Liquids-Focused, Multi-Basin Portfolio Strength

- Core positions in three of the top plays in North America
- 2.0 BBOE of proforma high quality proved reserves*
  - 2018 YE Reserve Life Index (RLI) of ~10 years
  - >80% increase to RLI since 2015
  - 55% liquids

2.0 BBOE of Proforma Proved Reserves*

* All reserves are stated on an SEC (U.S. protocol) basis. 2.1 BBOE of proforma NI 51-101 (Canadian protocol) proved reserves.

<table>
<thead>
<tr>
<th>ASSET</th>
<th>NET ACRES</th>
<th>2018 PRODUCTION</th>
<th>LIQUIDS %</th>
</tr>
</thead>
<tbody>
<tr>
<td>CORE</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>PERMIAN</td>
<td>115,000</td>
<td>92 MBOE/d</td>
<td>85%</td>
</tr>
<tr>
<td>ANADARCO</td>
<td>361,000</td>
<td>135 MBOE/d</td>
<td>60%</td>
</tr>
<tr>
<td>MONTNEY</td>
<td>793,000</td>
<td>191 MBOE/d</td>
<td>22%</td>
</tr>
<tr>
<td>OTHER</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>EAGLE FORD</td>
<td>42,000</td>
<td>45 MBOE/d</td>
<td>81%</td>
</tr>
<tr>
<td>WILLISTON</td>
<td>80,000</td>
<td>21 MBOE/d</td>
<td>84%</td>
</tr>
<tr>
<td>UINTA</td>
<td>222,000</td>
<td>20 MBOE/d</td>
<td>87%</td>
</tr>
<tr>
<td>DUVERNAY</td>
<td>264,000</td>
<td>18 MBOE/d</td>
<td>44%</td>
</tr>
</tbody>
</table>
Deep Inventory of High Return Growth Assets

Continued Liquids Growth*

>75% of 2019F** capital directed to core growth assets

20% less capital (2019F** vs 2018*) expected to generate growth and free cash flow†

2019F** Capital $2.7-2.9B

Permian
Montney
Anadarko
Other

* Full year proforma basis above includes legacy Newfield activity.
** Full year proforma basis above includes legacy Newfield activity from January 1 to February 13, 2019. On a reportable basis, amounts for volumes, capital and expenses exclude amounts for this period.
† Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures see the Company's website.
Creating Value Through Scale & Innovation

- **Proven expertise in cube development**
  - Concurrent, multi-stack development maximizes resource value and lowers well costs
  - Higher utilization of services & infrastructure
  - Reduced D&C cycle times

- **Supply chain management lowers costs, provides flexibility and ensures access to quality services**
  - Fully offsets cost inflation with sourcing and efficiency improvements
  - Unbundling of services drives efficiencies with vendors
  - Self-sourcing commodities (local sand, water, OCTG)

- **Centralized water infrastructure solutions**
  - D&C cost savings up to $300k/well
  - LOE savings up to ~$0.80/BOE

- **Innovative midstream and transport arrangements**
  - Scale enables flexible low-cost transportation and processing agreements
  - Improves realized pricing, revenues and returns
  - Market diversification creates value and manages risk

* Weighted average D&C cost from Duvernay, Eagle Ford, Montney, and Permian

Average D&C cost* reduction since 2015: 25%
Financial Flexibility

• **Commitment to maintaining a strong balance sheet**
  - Reduced long-term debt by nearly $3 billion from 2013 to 2018
  - Reduced long-term commitments by ~$4.3 billion from 2013 to 2018
  - Continue to manage to mid-cycle leverage target of 1.5x

• **Substantial liquidity**
  - $4.0 billion fully committed, unsecured, revolving credit facilities
  - Well dispersed long-term debt maturity profile

• **Capital structure improves free cash flow**
  - Lowered annual interest expense on debt by $193 million from 2013 to 2018
  - Decreased cost-of-capital through scale

• **Multi-basin model favored by credit agencies**
  - Commodity and geographic diversity reduces risk
  - Fitch and S&P recently upgraded to BBB from BBB-, Moody’s rated Ba1

---

Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures see the Company’s website.
Returning Capital to Shareholders

- Sold ~$13 billion of assets since 2013
  - >80% of production and proved reserves sold were natural gas

- Reshaped portfolio to liquids while returning cash to shareholders

- Expanded liquidity and lowered leverage to maintain flexibility to fund investor initiatives

- Ongoing commitment to return cash to shareholders
  - $1.25 billion buyback underway*
  - 25% increase in dividend as of Q1 2019*

* $1.25 billion share buyback for up to 149.4 million shares, 10% of Encana's float at February 27, 2019. Declaration and payment of future dividends is subject to Board approval. Q2 to date share buyback as at April 29, 2019.
2019 Program

- 75% activity focused on Midland, Martin and Upton counties
- Continuing to innovate completion design and cube development

FY 2019 PLAN

<table>
<thead>
<tr>
<th>Metric</th>
<th>Target</th>
</tr>
</thead>
<tbody>
<tr>
<td>ACREAGE (net acres) / AVERAGE WORKING INTEREST %</td>
<td>115,000 / 92%</td>
</tr>
<tr>
<td>2019 AVERAGE WORKING INTEREST (%)</td>
<td>96%</td>
</tr>
<tr>
<td>AVERAGE ROYALTY RATE (%)</td>
<td>25%</td>
</tr>
<tr>
<td>CAPITAL (net) ($MM)</td>
<td>$925 – $975</td>
</tr>
<tr>
<td>NET WELLS DRILLED</td>
<td>105 – 120</td>
</tr>
<tr>
<td>NET WELLS ON STREAM</td>
<td>105 – 120</td>
</tr>
<tr>
<td>D&amp;C COST ($MM/well)</td>
<td>$6.1</td>
</tr>
<tr>
<td>AVERAGE LATERAL LENGTH (ft)</td>
<td>8,500</td>
</tr>
</tbody>
</table>

TOTAL PRODUCTION SPLIT

<table>
<thead>
<tr>
<th>Component</th>
<th>Percentage</th>
</tr>
</thead>
<tbody>
<tr>
<td>OIL/CONDENSATE* %</td>
<td>65%</td>
</tr>
<tr>
<td>NGLs (C2 – C4) %</td>
<td>20%</td>
</tr>
<tr>
<td>NATURAL GAS %</td>
<td>15%</td>
</tr>
</tbody>
</table>

* Includes plant and field condensate
Core Growth Asset

- **Cube development yields free cash flow**\(^T\) and growth
  - ~Tripled liquids production since acquisition (Q4 2014)
  - >500 net wells drilled

- **Basin innovator with peer leading performance**
  - 20% reduction in D&C cost\(^*\) since entering the basin in 2014
    - Targeting $6.1 MM/well D&C cost in 2019
  - Spearheaded cube development
  - Pacesetting drilling times across the play
  - Leader in efficient water management

- **2019F**
  - $925 - 975 MM capital program
  - Load-levelled program with 4 drilling rigs
  - Continuing to innovate completion designs and cube development

---

\(^*\) Normalized to 2019 program average lateral length of 8,500 ft

\(^\text{**}\) Permian average daily production in Q4 2014.

\(^T\) Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures see the Company's website
Midstream And Marketing Overview

- Majority of oil production gathered via pipeline with access to multiple physical markets
- Firm gas gathering and NGL processing with access to Waha and Mont Belvieu markets
- Waha basis $0.25 fluctuation equals less than $3 MM cash flow in Q2 - Q4 2019 after hedge
- Secured market access to Gulf Coast refining/export markets

<table>
<thead>
<tr>
<th>Permian (1)</th>
<th>2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>WTI/MIDLAND DIFFERENTIAL HEDGES</td>
<td>18 Mmbls/d</td>
</tr>
<tr>
<td>SWAP PRICE (US$/bbl)</td>
<td>$(1.43)/bbl</td>
</tr>
<tr>
<td>FIRM OIL MARKET ACCESS</td>
<td>45 Mmbls/d</td>
</tr>
<tr>
<td>WAHA BASIS HEDGES</td>
<td>55 MMcf/d</td>
</tr>
<tr>
<td>SWAP PRICE (US$/Mcf)</td>
<td>$(0.54)/Mcf</td>
</tr>
</tbody>
</table>

(1) Q2 - Q4 2019 risk management positions as at March 31, 2019. Hedged volumes are converted to Mcf at a 1:1 ratio from MMbtu.
2019 Program

• >90% program focused in Kingfisher, Blaine and Canadian Counties
• Cube development expected to unlock significant synergies via reduced well costs and improved capital efficiency
  o $1 MM per well savings achieved, further savings identified
• Supply chain management and self-sourcing of services expected to unlock additional returns

<table>
<thead>
<tr>
<th>FY 2019 PLAN**</th>
</tr>
</thead>
<tbody>
<tr>
<td>ACREAGE (net acres) / AVERAGE WORKING INTEREST %</td>
</tr>
<tr>
<td>2019 AVERAGE WORKING INTEREST (%)</td>
</tr>
<tr>
<td>AVERAGE ROYALTY RATE (%)</td>
</tr>
<tr>
<td>CAPITAL (net) ($MM)</td>
</tr>
<tr>
<td>NET WELLS DRILLED</td>
</tr>
<tr>
<td>NET WELLS ON STREAM</td>
</tr>
<tr>
<td>2018 AVERAGE D&amp;C COST ($MM/well)</td>
</tr>
<tr>
<td>TARGETED D&amp;C COST ($MM/well)</td>
</tr>
<tr>
<td>LATERAL LENGTH (ft)</td>
</tr>
</tbody>
</table>

TOTAL PRODUCTION SPLIT

<table>
<thead>
<tr>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>OIL/CONDENSATE*</td>
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<tr>
<td>NGLs (C2 – C4)</td>
</tr>
<tr>
<td>NATURAL GAS</td>
</tr>
</tbody>
</table>

* Includes plant and field condensate
** Full year proforma basis above includes legacy Newfield activity from January 1 to February 13, 2019. On a reportable basis, amounts for volumes, capital (~$140MM) and expenses exclude amounts for this period.
**Core Growth Asset**

- **Liquids growth and free cash flow**\(^\text{f}\) generator
  - 134,800 BOE/d, 60% liquids in 2018
  - ~100% of core lands held by production

- **Targeting $1 MM well cost reduction**
  - Cube development drilling to commence in early Q2
  - $6.9 MM/well D&C cost* in 2H 2019: further well cost savings identified

- **2019F**
  - $800 - 850 MM capital program
  - Pivot to load-levelled program with 4 drilling rigs
  - Capital focused on STACK

---

* Normalized to 10,000 ft lateral length
** Full year combined basis above includes legacy Newfield activity from January 1 to February 13, 2019. On a reportable basis, amounts for volumes, capital (~$140MM) and expenses exclude amounts for this period.

\(^{f}\) Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures see the Company's website.
Midstream And Marketing Overview

- Majority of oil production gathered via pipeline with direct access to Cushing markets
- Segregated WTI oil stream provides premium pricing at Cushing
- Firm NGL processing with access to Mont Belvieu
- Firm gas transport with access to Perryville/Gulf Coast market
• Investment aligned with local market conditions
• ~Balanced activity between Cutbank Ridge Partnership (60% partnership interest) and Pipestone (100% working interest)
• ~C$100 MM of remaining third party capital to be fully consumed within Cutbank Ridge Partnership

**MONTNEY**

**2019 Program**

**FY 2019 PLAN**

<table>
<thead>
<tr>
<th>ACREAGE (net acres) / AVERAGE WORKING INTEREST %</th>
<th>793,000 / 64%</th>
</tr>
</thead>
<tbody>
<tr>
<td>- PIPESTONE ACREAGE / WI %</td>
<td>89,000 / 100%</td>
</tr>
<tr>
<td>2019 AVERAGE WORKING INTEREST (%)</td>
<td>72%</td>
</tr>
<tr>
<td>AVERAGE ROYALTY RATE (%)</td>
<td>5 – 10%</td>
</tr>
<tr>
<td>CAPITAL (net) ($MM)</td>
<td>$350 – $400</td>
</tr>
<tr>
<td>NET WELLS DRILLED</td>
<td>60 – 70</td>
</tr>
<tr>
<td>NET WELLS ON STREAM</td>
<td>70 – 80</td>
</tr>
<tr>
<td>D&amp;C COST ($MM/well)</td>
<td>$4.3</td>
</tr>
<tr>
<td>AVERAGE LATERAL LENGTH (ft)</td>
<td>7,900</td>
</tr>
</tbody>
</table>

**TOTAL PRODUCTION SPLIT**

| OIL/CONDENSATE* %                              | 18%           |
| NGLs (C2 – C4) %                               | 7%            |
| NATURAL GAS %                                  | 75%           |

* Includes plant and field condensate
Core Growth Asset

- **Self-funded multi-year liquids growth**
  - More than tripled liquids production since 2015
  - >275 net wells drilled since 2015

- **Basin-leading cost and productivity performance**
  - >30% reduction in D&C cost* since 2015
    - Targeting $4.3 MM/well D&C cost in 2019

- **2019F**
  - $350 - 400 MM capital program
  - Load-levelled program with 4 drilling rigs
  - Investment aligned with local market conditions

---

* Normalized to lateral length of 7,900 ft
** Excludes divested volumes in 2015 and 2016
Midstream And Marketing Overview

- Combination of firm export capacity and basis hedges to manage AECO gas price* risk
  - Realized price including hedge expected to be ~$0.50 below NYMEX in 2019
  - AECO US$0.25 fluctuation equals less than US $15MM cash flow in 2019 Q2-Q4 after hedge
- 100% firm capacity secured on NGTL for expected production growth – limited curtailment risk
- Condensate sold into local market at ~WTI prices

Western Canada (1)

<table>
<thead>
<tr>
<th></th>
<th>2019 – 2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>AECO BASIS HEDGES</td>
<td>455 MMcf/d</td>
</tr>
<tr>
<td>SWAP PRICE US$/Mcf*</td>
<td>$(0.88)/Mcf</td>
</tr>
<tr>
<td>TRANSPORT TO DAWN</td>
<td>316 MMcf/d</td>
</tr>
<tr>
<td>TRANSPORT TO SUMAS / MALIN</td>
<td>130 MMcf/d</td>
</tr>
<tr>
<td>TRANSPORT TO CHICAGO</td>
<td>100 MMcf/d</td>
</tr>
</tbody>
</table>

(1) Q2-Q4 2019 and full year 2020 risk management positions as at March 31, 2019
* Price stated is the differential versus NYMEX pricing. Hedged and transport volumes are converted to Mcf at a 1:1 ratio from MMBtu.
## Optimizing Free Cash Flow

### Other Assets

- **80% of capital weighted to 1H 2019**
  - Maximizes rig and frac spread utilization
- **Focused D&C capital with minimal infrastructure and non-well capital requirements**
- **Wells drilled generate similar returns as Core 3**

### FY 2019 Plan*

<table>
<thead>
<tr>
<th></th>
<th>Eagle Ford</th>
<th>Williston</th>
<th>Duvernay</th>
<th>Uinta</th>
</tr>
</thead>
<tbody>
<tr>
<td>Acreage (net acres) / Average Working Interest (%)</td>
<td>42,000 / 96%</td>
<td>80,000 / 59%</td>
<td>264,000 / 51%</td>
<td>222,000 / 80%</td>
</tr>
<tr>
<td>2019 Avg Working Interest (%)</td>
<td>86%</td>
<td>70%</td>
<td>51%</td>
<td>70%</td>
</tr>
<tr>
<td>Average Royalty Rate (%)</td>
<td>20 – 25%</td>
<td>17 – 20%</td>
<td>5 – 10%</td>
<td>17 – 20%</td>
</tr>
<tr>
<td>Capital (net) ($MM)</td>
<td>$250 – 280</td>
<td>$110 – 130</td>
<td>$100 – 120</td>
<td>$50 – 70</td>
</tr>
</tbody>
</table>

### Total Production Split*

<table>
<thead>
<tr>
<th></th>
<th>Eagle Ford</th>
<th>Williston</th>
<th>Duvernay</th>
<th>Uinta</th>
</tr>
</thead>
<tbody>
<tr>
<td>Oil/Condensate** %</td>
<td>66%</td>
<td>70%</td>
<td>36%</td>
<td>83%</td>
</tr>
<tr>
<td>NGLs (C2 – C4) %</td>
<td>15%</td>
<td>13%</td>
<td>6%</td>
<td>3%</td>
</tr>
<tr>
<td>Natural Gas %</td>
<td>19%</td>
<td>17%</td>
<td>58%</td>
<td>14%</td>
</tr>
</tbody>
</table>

* Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures see the Company’s website.

** Full year proforma basis above includes legacy Newfield activity from January 1 to February 13, 2019.

** Includes plant and field condensate
<table>
<thead>
<tr>
<th>Play</th>
<th>IP30 (BOE/d)</th>
<th>IP180 (BOE/d)</th>
<th>EUR/Well (Mbbls)</th>
<th>EUR/Well (MBOE)</th>
<th>GOR (scf/bbl)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Permian Basin¹</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Midland/Upton</td>
<td>985</td>
<td>700</td>
<td>610</td>
<td>1,020</td>
<td>2,800</td>
</tr>
<tr>
<td>Martin</td>
<td>950</td>
<td>650</td>
<td>675</td>
<td>1,000</td>
<td>2,000</td>
</tr>
<tr>
<td>Howard</td>
<td>825</td>
<td>600</td>
<td>550</td>
<td>875</td>
<td>2,450</td>
</tr>
<tr>
<td>Glasscock</td>
<td>800</td>
<td>550</td>
<td>530</td>
<td>765</td>
<td>1,960</td>
</tr>
<tr>
<td>Anadarko²</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>STACK</td>
<td>1,300</td>
<td>850</td>
<td>860</td>
<td>1,300</td>
<td>5,800</td>
</tr>
<tr>
<td>Montney³</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Pipestone</td>
<td>800</td>
<td>1,000</td>
<td>525</td>
<td>950</td>
<td>150 - 300</td>
</tr>
<tr>
<td>Tower Very Rich Gas Condensate</td>
<td>1,400</td>
<td>1,000</td>
<td>300</td>
<td>750</td>
<td>100 - 200</td>
</tr>
<tr>
<td>Tower Gas Condensate</td>
<td>1,400</td>
<td>1,300</td>
<td>300</td>
<td>1,800</td>
<td>20 - 50</td>
</tr>
<tr>
<td>Dawson South</td>
<td>1.850</td>
<td>1,800</td>
<td>400</td>
<td>2,100</td>
<td>30 - 50</td>
</tr>
</tbody>
</table>

(1) Type curves are stated on a three stream basis with an average lateral length of 7,500’.
(2) Type curves are stated on a three stream basis with an average lateral length of 10,000’.
(3) Type curves are stated on a shrunk condensate and a raw gas basis with lateral lengths of 8,200 - 9,800’.
Cost Effective Water Management

**Permit – Martin County Water Hub**
- Area specific solutions
  - Permian
    - Combination Encana-owned low-cost water hubs and third party providers
    - Recycled >50% of produced water in 2018
  - Anadarko
    - 30,000 barrel per day Barton water recycling and treatment facility
    - >75 miles of permanent pipe and >13 MMbbls of water storage
  - Montney
    - Non-potable water sourced from deep formations recycled through two centralized facilities
- Improves capital efficiency and de-risks supply
- Reducing all-in water handling & sourcing costs
  - D&C cost savings up to $300k/well
  - LOE savings up to ~$0.80/BOE
# Reconciliation of Full Year Guidance to Reportable

## 2019 Guidance: Reportable Versus Full Year

<table>
<thead>
<tr>
<th></th>
<th>2019 Reportable Guidance</th>
<th>Impact of Newfield Jan 1 - Feb 13, 2019</th>
<th>Full Year Proforma</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>CAPITAL INVESTMENT ($ BILLION)</strong></td>
<td>2.5 – 2.7</td>
<td>0.2</td>
<td>2.7 – 2.9</td>
</tr>
<tr>
<td><strong>TOTAL LIQUIDS (MBBLS/d)</strong></td>
<td>290 – 310</td>
<td>15</td>
<td>300 – 320</td>
</tr>
<tr>
<td><strong>NATURAL GAS (MMCF/d)</strong></td>
<td>1,500 – 1,600</td>
<td>55</td>
<td>1,550 – 1,650</td>
</tr>
<tr>
<td><strong>TOTAL PRODUCTION (MBOE/d)</strong></td>
<td>540 – 580</td>
<td>24</td>
<td>560 – 600</td>
</tr>
<tr>
<td><strong>TOTAL COSTS PER BOE</strong>*&lt;sup&gt;*&lt;/sup&gt;**</td>
<td>12.75 – 13.25</td>
<td>-</td>
<td>12.75 – 13.25</td>
</tr>
<tr>
<td><strong>UPSTREAM OPERATING AND T&amp;P, PRODUCTION AND MINERAL TAXES PLUS ADMINISTRATIVE</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Reportable: ECA plus Newfield post close February 13, 2019
Impact of Newfield Jan 1 – Feb 13, 2019: Newfield activity January 1, 2019 – February 13, 2019
Full year proforma: Results of ECA + Newfield combined for all of 2019

- Per unit costs expected to fall through the year
- Excludes Q1 acquisition and restructuring costs incurred in 2019 at $144 million

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* Excludes the impact of long-term incentive costs and restructuring costs. Bow office building lease costs are included in these combined costs.
COST CONTROL OF CORPORATE ITEMS ENHANCES PER UNIT MARGIN

Maximizing Margin

• G&A >30% lower on a per BOE\(^1\) basis
  o On track for $150 million in annualized G&A savings, increased by $25 million versus original estimate

• Lower quarterly G&A run rate for remainder of year: ~$75 MM down from prior estimate of ~$90 MM
  o Run-rate G&A costs include approximately $25 MM per quarter for the BOW lease costs, previously classified in interest expense and corporate segment operating costs
  o About 50% of BOW related costs included in G&A are recovered through sub-lease revenues
  o Excluding the impact of the Bow office cost reclassification, quarterly run-rate G&A costs are down from $65 MM previous estimate to ~$50 MM

• Market optimization segment loss of ~$40 MM per quarter

• Interest expense on debt of ~$100 MM per quarter

(1) G&A per BOE includes the impact of Bow office related costs and excludes LTI's
(2) Full year proforma basis above includes legacy Newfield activity in 2018 and 2019; 2019F excludes $113 MM of restructuring costs in Q1 2019
### Projected Composition of Total Production

#### Product Value Chain Excluding Hedge

<table>
<thead>
<tr>
<th>Product</th>
<th>Canada</th>
<th></th>
<th>US</th>
<th></th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>2019F (1) (Mbbls/d)</td>
<td>2019F Pricing (% WTI)</td>
<td>2019F (1) (Mbbls/d)</td>
<td>2019F Pricing (% WTI)</td>
</tr>
<tr>
<td><strong>Oil (2)</strong></td>
<td>0 – 1</td>
<td>70%</td>
<td>175 – 180</td>
<td>98%</td>
</tr>
<tr>
<td><strong>Condensate (3)</strong></td>
<td>40 – 43</td>
<td>89%</td>
<td>9 – 11</td>
<td>80%</td>
</tr>
<tr>
<td><strong>Butane</strong></td>
<td>6 – 8</td>
<td>19%</td>
<td>12 – 13</td>
<td>50%</td>
</tr>
<tr>
<td><strong>Propane</strong></td>
<td>7 – 9</td>
<td>24%</td>
<td>23 – 26</td>
<td>40%</td>
</tr>
<tr>
<td><strong>Ethane</strong></td>
<td>0 – 1</td>
<td>18%</td>
<td>29 – 31</td>
<td>12%</td>
</tr>
<tr>
<td><strong>Natural Gas</strong></td>
<td>950 – 1,050</td>
<td>73%</td>
<td>550 – 650</td>
<td>75%</td>
</tr>
</tbody>
</table>

---

(1) 2019F based on company guidance as at February 28, 2019, excluding impact of hedges; production ranges are not additive;
(2) US Oil production range includes estimated volumes for China
(3) Includes plant condensate
Hedging Summary

**WTI Oil**
- ~$250 MM per $5.00/bbl increase in NYMEX WTI to 2019 Q2-Q4 cash flow after hedge
- Majority of oil hedges through option based structures allows for upside capture to ~$70.00/bbl

**NYMEX Gas**
- ~$55 MM per $0.25/Mcf change in NYMEX gas to 2019 Q2-Q4 cash flow after hedge

**Foreign Exchange**
- ~$15 MM per $0.05 change in F/X to 2019 Q2-Q4 cash flow after hedge

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**BENCHMARK HEDGES**

<table>
<thead>
<tr>
<th>Hedging Strategy</th>
<th>2019 (2)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Oil and Condensate</strong></td>
<td></td>
</tr>
<tr>
<td>WTI FIXED PRICE SWAP</td>
<td>35 Mbbls/d</td>
</tr>
<tr>
<td>SWAP PRICE (US$/bbl)</td>
<td>$60.31/bbl</td>
</tr>
<tr>
<td>WTI 3-WAY OPTION</td>
<td>61 Mbbls/d</td>
</tr>
<tr>
<td>SHORT PUT (US$/bbl)</td>
<td>$48.15/bbl</td>
</tr>
<tr>
<td>LONG PUT (US$/bbl)</td>
<td>$58.96/bbl</td>
</tr>
<tr>
<td>SHORT CALL (US$/bbl)</td>
<td>$68.74/bbl</td>
</tr>
<tr>
<td>WTI COSTLESS COLLAR</td>
<td></td>
</tr>
<tr>
<td>LONG PUT (US$/bbl)</td>
<td>10 Mbbls/d</td>
</tr>
<tr>
<td>SHORT CALL (US$/bbl)</td>
<td>$55.00</td>
</tr>
</tbody>
</table>

| Natural Gas | |
| NYMEX FIXED PRICE SWAP | 892 MMcf/d |
| SWAP PRICE US$/Mcf | $2.75/Mcf |
| NYMEX COSTLESS COLLAR | 66 MMcf/d |
| LONG PUT (US$/Mcf) | $2.91/Mcf |
| SHORT CALL (US$/Mcf) | $3.06/Mcf |

| Foreign Exchange | |
| Notional US$ Currency Swaps | US$750 MM |
| Average Exchange Rate US$ to C$1 | US$0.7516 |

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(1) Rest of year sensitivity based on mid-point of guidance volumes
(2) Risk management positions as at March 31, 2019
(3) Hedged volumes are converted to Mcf at a 1:1 ratio from MMBtu
T Non-GAAP measures defined in advisories. For additional information regarding non-GAAP measures see the Company's website.
Disciplined Financial Management

- Total debt reduced by ~$3 billion since Y/E 2013 to Y/E 2018
- Significant financial flexibility
- Well-dispersed maturity profile
- Multi-basin model favored by credit agencies
- $4.0B fully committed, unsecured, revolving credit facilities
FUTURE ORIENTED INFORMATION

This presentation contains forward-looking statements or information (collectively, “FLS”) within the meaning of applicable securities legislation, including Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended. FLS include:

- meeting or exceeding Encana’s corporate guidance
- anticipated capital program, including focus of development and allocation thereof, number of wells on stream, level of capital productivity, expected return and source of funding
- anticipated production, including growth from core assets, cash flow, free cash flow, capital coverage, payout, profit, net present value, rates of return, recovery, return on capital employed, production and execution efficiency, operating, income and cash flow margin, and margin expansion, including expected timeframes
- well performance, completions intensity, location, running room and scale of assets, including its competitiveness and pace of growth against peers
- number of potential drilling locations, well spacing, number of wells per pad, decline rate, rig count, rig release metrics, focus and timing of drilling, anticipated vertical and horizontal drilling, cycle times, commodity composition, gas-oil ratios, and operating performance compared to type curves
- pacesetting metrics being indicative of future well performance and costs, and sustainability thereof
- timing, success and benefits from innovation, cube development approach, advanced completions design, scale of development, high-intensity completions and precision targeting, and transferability of ideas
- anticipated efficiencies and synergies, including drilling and completion cycle times, operating, corporate, transportation and processing, staffing, services and materials secured and supply chain management
- leading positions and quality of plays in North America
- anticipated reserves and resources, including product types and stacked resource potential
- expected transportation and processing capacity, commitments, curtailments and restrictions, including flexibility of commercial arrangements and costs and timing of certain infrastructure being operational
- anticipated return of capital model and priorities therein, management of balance sheet and credit rating, access to liquidity, available cash, and return of capital including anticipated dividends and size and timing of share buyback
- expected net debt, net debt to adjusted EBITDA, target leverage, financial capacity and other debt metrics
- options to maximize shareholder returns and timing thereof
- commodity price outlook
- outcomes of risk management program, including exposure to commodity prices and foreign exchange, amount of hedged production, market access, market diversification strategy and physical sales locations
- environmental, health and safety performance

FLS involve assumptions, risks and uncertainties that may cause such statements not to occur or results to differ materially. These assumptions include: future commodity prices and differentials; foreign exchange rates; assumptions contained in corporate guidance and as specified herein; data contained in key modeling statistics; availability of attractive hedges and enforceability of risk management program; results from innovations; expectation that counterparties will fulfill their obligations; access to transportation and processing facilities; assumed tax, royalty and regulatory regimes; and expectations and projections made in light of Encana’s historical experience and its perception of historical trends. Risks and uncertainties include: integration of Encana and Newfield and the ability to recognize the anticipated benefits; ability to generate sufficient cash flow to meet obligations; commodity price volatility; ability to secure adequate transportation and potential pipeline curtailments; variability and discretion to declare and pay dividends, if any; amount and timing of share repurchases; timing and costs of well, facilities and pipeline construction; business interruption, property and casualty losses or unexpected technical difficulties; counterparty and credit risk; changes in credit rating and its impact on access to liquidity; currency and interest rates; risks inherent in corporate guidance; failure to achieve cost and efficiency initiatives; risks in marketing operations; risks associated with technology; changes in or interpretation of laws or regulations; risks associated with existing and potential lawsuits and regulatory actions; impact of disputes arising with partners, including suspension of certain obligations and inability to dispose of assets or interests in certain arrangements; ability to acquire or find additional reserves; imprecision of reserves estimates and estimates of recoverable quantities and future net revenue; risks associated with past and future acquisitions or divestitures of certain assets or other transactions or receipt of amounts contemplated under the transactions agreements (such transactions may include third-party capital investments, farm-outs or partnerships, which Encana may refer to from time to time as “partnerships” or “joint ventures” and the funds received in respect thereof which Encana may refer to from time to time as “proceeds”, “deferred purchase price” and/or “carry capital”, regardless of the legal form) as a result of various conditions not being met; and other risks and uncertainties, as described in Encana’s most recent Annual Report on Form 10-K and Quarterly Report on Form 10-Q and as described from time to time in Encana’s other periodic filings as filed on SEDAR and EDGAR.

Although Encana believes such FLS are reasonable, there can be no assurance that the above assumptions, risks and uncertainties are not correct. FLS are made as of the date hereof and, except as required by law, Encana undertakes no obligation to update or revise any FLS. Certain future oriented financial information or financial outlook information is included in this presentation to communicate current expectations as to Encana’s performance. Readers are cautioned that it may not be appropriate for other purposes. Rates of return for a particular asset or well are on a before-tax basis and are based on specified commodity prices with local pricing offsets, capital costs associated with drilling, completing and equipping a well, field operating expenses and certain type curve assumptions. Pacesetter well costs for a particular asset are a composite of the best drilling performance and best completions performance well in the current quarter in such asset and are presented for comparison purposes. Drilling and completions costs have been normalized as specified in this presentation based on certain lateral lengths for a particular asset. For convenience, references to “Encana”, the “Company”, “we”, “us” and “our” may, where applicable, refer only to or include any relevant direct and indirect subsidiary corporations and partnerships (“Subsidiaries”) of Encana Corporation, and the assets, activities and initiatives of such Subsidiaries.
ADVISORY REGARDING OIL & GAS INFORMATION

All reserves estimates in this presentation are effective as of December 31, 2018, prepared by qualified reserves evaluators in accordance with procedures and standards contained in the Canadian Oil and Gas Evaluation ("COGE") Handbook, National Instrument 51-101 (NI 51-101) and SEC regulations, as applicable. On August 14, 2017, Encana was granted an exemption by the Canadian Securities Administrators from the requirements under NI 51-101 that each qualified reserves evaluator or qualified reserves auditor appointed under section 3.2 of NI 51-101 and who execute the report under Item 2 of Section 2 of NI 51-101 be independent of Encana. Detailed Canadian and U.S. protocol disclosure will be contained in the Form 51-101F1 and Annual Report on Form 10-K, respectively. Information on the forecast prices and costs used in preparing the Canadian protocol estimates are contained in the Form 51-101F1. For additional information relating to risks associated with the estimates of reserves, see "Item 1A. Risk Factors" of the Annual Report on Form 10-K.

Reserves are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: analysis of drilling, geological, geophysical and engineering data, the use of established technology, and specified economic conditions, which are generally accepted as being reasonable. Proved reserves are those reserves which can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Encana uses the terms play and resource play, Play encompasses resource plays, geological formations and conventional plays. Resource play describes an accumulation of hydrocarbons known to exist over a large areal expanse and/or thick vertical section, which when compared to a conventional play, typically has a lower geological and/or commercial development risk and lower average decline rate. As used by Encana, estimated ultimate recovery ("EUR") has the meaning set out jointly by the Society of Petroleum Engineers and World Petroleum Congress in the year 2000, being those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefore. Encana has provided information with respect to its assets which are "analogous information" as defined in NI 51-101, including estimates of EUR and production type curves. This analogous information is presented on a basin, sub-basin or area basis utilizing data derived from Encana’s internal sources, as well as from a variety of publicly available information sources which are predominantly independent in nature. Production type curves are based on a methodology of analog, empirical and theoretical assessments and workflow with consideration of the specific asset, and as depicted in this presentation, is representative of Encana's current program, including relative to current performance, but are not necessarily indicative of ultimate recovery. Some of this data may not have been prepared by qualified reserves evaluators, may have been prepared based on internal estimates, and the preparation of any estimates may not be in strict accordance with COGEH. Estimates by engineering and geo-technical practitioners may vary and the differences may be significant. Encana believes that the provision of this analogous information is relevant to Encana’s oil and gas activities, given its acreage position and operations (either ongoing or planned) in the areas in question, and such information has been updated as of the date hereof unless otherwise specified. Due to the early life nature of the various emerging plays discussed in this presentation, EUR is the most relevant specific assignable category of estimated resources. There is no certainty that any portion of the resources will be discovered. There is no certainty that it will be commercially viable to produce any portion of the estimated EUR. Estimates of Encana potential gross inventory locations, including premium return well inventory, include proved undeveloped reserves, probable undeveloped reserves, un-risked 2C contingent resources and unbooked inventory locations. As of December 31, 2018, on a proforma basis, 2,012 proved undeveloped locations, 3,844 probable undeveloped locations and 3,265 un-risked 2C contingent resource locations (in the development pending, development on-hold or development unclarified project maturity sub-classes) have been categorized as either reserves or contingent resources. Unbooked locations have not been classified as either reserves or resources and are internal estimates that have been identified by management as an estimation of Encana’s multi-year potential drilling activities based on evaluation of applicable geologic, seismic, engineering, production, resource and acreage information. There is no certainty that Encana will drill all unbooked locations and if drilled there is no certainty that such wells will result in additional oil and gas reserves, resources or production. The locations on which Encana will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of capital, regulatory and partner approvals, seasonal restrictions, equipment and personnel, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained, production rate recovery, transportation constraints and other factors. While certain of the unbooked locations may have been de-risked by drilling existing wells in relative close proximity to such locations, many of other unbooked locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional proved or probable reserves, resources or production.

30-day IP and other short-term rates are not necessarily indicative of long-term performance or of ultimate recovery. The conversion of natural gas volumes to barrels of oil equivalent ("BOE") is on the basis of six thousand cubic feet to one barrel. BOE is based on a generic energy equivalency conversion method primarily applicable at the burner tip and does not represent economic value equivalency at the wellhead. Readers are cautioned that BOE may be misleading, particularly if used in isolation.
NON-GAAP MEASURES

Certain measures in this presentation do not have any standardized meaning as prescribed by U.S. GAAP and, therefore, are considered non-GAAP measures. These measures may not be comparable to similar measures presented by other companies. These measures have been provided for meaningful comparisons between current results and other periods and should not be viewed as a substitute for measures reported under U.S. GAAP. For additional information regarding non-GAAP measures, including reconciliations, see the Company’s website and Encana’s most recent Annual Report as filed on SEDAR and EDGAR. Non-GAAP measures include:

- **Non-GAAP Cash Flow, Non-GAAP Cash Flow Per Share (CFPS), Non-GAAP Free Cash Flow and Non-GAAP Cash Flow Margin** – Non-GAAP Cash Flow (or Cash Flow) is defined as cash from (used in) operating activities excluding net change in other assets and liabilities, net change in non-cash working capital and current tax on sale of assets. Non-GAAP CFPS is Non-GAAP Cash Flow divided by the weighted average number of common shares outstanding. Non-GAAP Free Cash Flow (or Free Cash Flow) is Non-GAAP Cash Flow in excess of capital expenditures, excluding net acquisitions and divestitures. Non-GAAP Cash Flow Margin is Non-GAAP Cash Flow per BOE of production. Management believes these measures are useful to the company and its investors as a measure of operating and financial performance across periods and against other companies in the industry, and are an indication of the company’s ability to generate cash to finance capital programs, to service debt and to meet other financial obligations. These measures may be used, along with other measures, in the calculation of certain performance targets for the company’s management and employees.

- **Total Costs per BOE** is defined as the summation of production, mineral and other taxes, upstream transportation and processing expense, upstream operating expense and administrative expense, excluding the impact of long-term incentive and restructuring costs, per BOE of production. Management believes this measure is useful to the company and its investors as a measure of operational efficiency across periods.

- **Non-GAAP Operating Earnings (Loss)** – is defined as Net Earnings (Loss) excluding non-recurring or non-cash items that management believes reduces the comparability of the company’s financial performance between periods. These items may include, but are not limited to, unrealized gains/losses on risk management, impairments, restructuring charges, non-operating foreign exchange gains/losses, gains/losses on divestitures and gains on debt retirement. Income taxes may include valuation allowances and the provision related to the pre-tax items listed, as well as income taxes related to divestitures and U.S. tax reform, and adjustments to normalize the effect of income taxes calculated using the estimated annual effective income tax rate.

- **Net Debt, Adjusted EBITDA and Net Debt to Adjusted EBITDA** – Net Debt is defined as long-term debt, including the current portion, less cash and cash equivalents. Management uses this measure as a substitute for total long-term debt in certain internal debt metrics as a measure of the company’s ability to service debt obligations and as an indicator of the company’s overall financial strength. Adjusted EBITDA is defined as trailing 12-month net earnings (loss) before income taxes, DD&A, impairments, accretion of asset retirement obligation, interest, unrealized gains/losses on risk management, foreign exchange gains/losses, gains/losses on divestitures and other gains/losses. Net Debt to Adjusted EBITDA is monitored by management as an indicator of the company’s overall financial strength.