A Lundin Group Company

International Petroleum Corp. Internationally Focused Upstream Company

May 2019
International Petroleum Corp.

Corporate Strategy

- Deliver operational excellence
- Maintain financial resilience
- Maximize the value of our resource base
- Grow through M&A
# International Petroleum Corp.
## Q1 2019 Highlights

<table>
<thead>
<tr>
<th>Category</th>
<th>Highlights</th>
</tr>
</thead>
</table>
| **Production Guidance**| - Q1 production at **44,400** boepd
- 2019 guidance: **46,000 to 50,000** boepd retained
- 2019 forecast exit rate **>50,000** boepd
- Production growth targeted in all countries |
| **Operating Costs**    | - Operating costs of **13.2** USD/boe; in line with guidance |
| **Organic Growth**     | - Capital expenditure increase from **166 to 188** MUSD
- Suffield N2N EOR project execution
- Additional conventional drilling in Canada – Five wells on acquired BlackPearl properties |
| **Operating Cash Flow**| - Strong cash flow generation
- Full year 2019 OCF forecast of **163 to 330** MUSD
- Q1 OCF of **83** MUSD, **25%** of high end guidance at **70** USD/bbl Brent (Brent avg 63 USD/bbl) |
| **Liquidity**          | - Increased capital programme fully funded from cash flow |
| **Resource Base**      | - **>2x** increase to 288 MMboe; >1.1 billion boe 2P+2C; 16 yr RLI |
| **Shareholder Value**  | - **37%** increase in NAV per share to **12.40** USD, IPC trading at **58%** discount |
| **Business Development**| - Acquisition of **243** MMboe of additional contingent resource at Blackrod\(^{(2)}\) at very low cost
- Opportunistic approach to further acquisitions |
| **HSE**                | - **No** material incidents                                                                                                                                 |

\(^{(1)}\) Non-IFRS measure, see MD&A  
\(^{(2)}\) As at December 31, 2018, see Reader Advisory and MD&A
International Petroleum Corp.

Track Record of Reserves Growth

- **Proven track record of reserves increases through organic growth**

- **103% reserves replacement ratio in 2018**
  - **174% in France** ⇒ Villeperdue reservoir performance upgrade and Villeperdue West project
  - **109% in Malaysia** ⇒ Addition of 3 infill wells and reservoir performance upgrade
  - **98% in Canada - Suffield** ⇒ Gas optimisation performance

- **Year on year reserve increases in all countries**

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1) See Reader Advisory and MD&A
>100% reserves replacement in 2018

More than doubled 2P reserves to 288 MMboe\(^{(1)}\)

Increased reserves life index (RLI) from 11 to 16 years\(^{(1)}\)

More than 13x increase in Contingent Resource base\(^{(1,2)}\)

\(^{(1)}\) As at December 31, 2018. See Reader Advisory and MD&A
\(^{(2)}\) Excluding acquisition of Blackrod resources of 243 MMboe
International Petroleum Corp.
Production Growth

- Production guidance of 46,000 to 50,000 boepd
- > 50,000 boepd exit rate forecast
Capital programme increased from high end guidance of 166 MUSD to 188 MUSD
- Fully funded from 2019 cash flow

### Canada – Suffield
- Approved
  - Oil drilling and gas optimisation
    - On track/ahead of expectation
- Added
  - N2N EOR project sanction

### Canada – Onion Lake / Other
- Approved
  - Onion Lake production optimisation
    - On track, slightly slower ramp up due to cold weather
  - Blackrod pilot (1 well pair)
    - On track for May spud
- Added
  - Play openers: Acquired BlackPearl conventional land
    - 5 wells; opens up to 130 drilling locations
  - Blackrod land acquisition
    - 243 MMboe CR \(^{(1)}\)

### Malaysia
- Approved
  - 3 infill wells
    - Keruing exploration and infill pilot wells
      - On track for Q2 spud

### France
- Approved
  - Execution of Vert-La-Gravelle Phase 1
    - On track for Q2 spud

\(^{(1)}\) As at December 31, 2018, see Reader Advisory and MD&A
International Petroleum Corp.

Organic Growth

- Additional 22 MUSD capex programme approved in Canada
- Flexibility to increase or decrease based on commodity prices
- Targeting growth in all countries
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Operating Cash Flow (MUSD)\(^{(1)}\)

- **2017 Actual**: 138
- **2018 Actual**: 279\(^{(2)}\)
- **2019 Guidance\(^{(3)}\)**:
  - **Low Case**
    - WTI-WCS differential: 232 (60 USD/bbl)
    - Production: 36% (265 MUSD)
  - **High Case**
    - WTI-WCS differential: 332 (70 USD/bbl)
    - Production: 25% (258 MUSD)

\(^{(1)}\) Non-IFRS measure, See MD&A
\(^{(2)}\) Including OCF related to Netherlands assets disposed in December 2018
\(^{(3)}\) At mid-point of 2019 production guidance
International Petroleum Corp.

Net Asset Value (MUSD)\(^{(1)}\)

<table>
<thead>
<tr>
<th>Year</th>
<th>Net Debt (^{(2)})</th>
<th>NAV (^{(1)})</th>
<th>IPCO Market Cap (^{(3)})</th>
</tr>
</thead>
<tbody>
<tr>
<td>2017</td>
<td>543</td>
<td>2,314</td>
<td>847</td>
</tr>
<tr>
<td>2018</td>
<td>1,151</td>
<td>1,274</td>
<td>1,151</td>
</tr>
<tr>
<td>2019</td>
<td>526</td>
<td>514</td>
<td>1,274</td>
</tr>
</tbody>
</table>

\(\text{With YE 2017 Pricing}\)

\(~58\%\) discount to NAV

1) As at December 31, 2018, see Reader Advisory and MD&A
2) Non-IFRS measure, see MD&A
3) Based on the price of IPC shares as at April 26\(^{th}\), 2019, converted to USD (SEK 49.10 ; SEK/USD 9.49)
As at December 31, 2018, see Reader Advisory and MD&A
Appendix

2019 Activity
International Petroleum Corp.
2019 Production Guidance

- Production guidance for 2019 retained: 46,000 to 50,000 boepd net
- Production growth targeted in all countries
  - Suffield gas optimisation and oil drilling
  - Onion Lake ramp up
  - Malaysia infill wells
  - France Vert-La-Gravelle project
International Petroleum Corp.

Operating Costs\(^{(1)}\)

- **2019 full year operating costs forecast at 12.9 USD/boe**
  - Includes production optimisation, workovers and maintenance provisions

- **Q1 operating costs in line with guidance at 13.2 USD/boe**

\(^{(1)}\) Non-IFRS measure, see Reader Advisory and MD&A

OPEX shown is net of self to self lease payments
Exploration and Appraisal Expenditure (net)

- **Blackrod** -> 744 MMboe of Contingent Resources
  - Acquisition of an additional 243 MMboe
- **Keruing** -> targeting 3 to 16 MMboe of Prospective Resources

**Canada** – MUSD 10
- Blackrod 3rd pilot well pair
- Blackrod land acquisition

**Malaysia** – MUSD 16
- Keruing exploration well
- Bertam Infill landing pilots

**2019 Guidance (3)**: MUSD 26

- **Malaysia**: 62%
- **Canada**: 38%

1. Best estimate unrisked contingent resources, see Reader Advisory and MD&A
2. Gross unrisked prospective resources, see Reader Advisory and MD&A
3. Excluding low cost acquisition of Blackrod lands
Appendix

Canada
### IPC - Canada

**Asset Overview - >1 Billion Barrels of Resource\(^1\)**

#### Suffield Area
- Conventional heavy oil and natural gas
- 2018 production 23,900 boepd
- Focus on gas optimisation and oil development opportunities in 2019

#### Onion Lake
- Thermal and conventional heavy oil
- 2018 production 9,500 boepd
- Phase 2 Onion Lake thermal facilities completed in 2018, capacity now at 12,000 bopd
- Further production ramp up and facility optimisation through 2019

#### Blackrod
- Thermal heavy oil
- IPC’s single largest contingent resource opportunity
- Third pilot well pair planned for 2019

#### Other Conventional Heavy Oil
- Mooney alkaline-surfactant-polymer flood
- John Lake and Reita Lake conventional heavy oil

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\(^1\) 2P reserves and 2C resources as at December 31, 2018, see Reader Advisory and MD&A, excludes acquisition of 243 MMboe at Blackrod
Suffield Area - Oil Development

- **2019 firm programme – 17 development wells**
  - Locations spread across South Gibson, Gibson Lake, North Dieppe, and N2N areas
  - Progress preparations for 2020 drilling campaign

- **Favourable economic returns in current price environment**
  - Breakeven oil price ~23 USD/bbl WCS price

Example - South Gibson

2019 drilling locations
IPC - Canada
Suffield Area - Gas Optimisation

- Successfully offset shallow gas declines in 2018
  - Focus on increased swabbing activity in 1H 2018
  - Recompletion campaign began in Q4 2018 – early results encouraging

- 2019 plan
  - Continue swabbing and optimisation efforts
  - Capital budget to execute an additional ~150 recompletions
  - Low breakeven 0.2 to 1.6 CAD/Mcf

Example - Alderson 2 Area Production

$^{(1)}$ IHS Accumap
N2N enhanced oil recovery project sanctioned
- High value project given 22 MCAD Cenovus pre funding
- Facility CAPEX and 9 wells already completed (Cenovus)
- Additional 8 wells, 3 conversions and facility commissioning required
- Expected peak production adds of 1,250 bopd in 2-3 years (18% increase on current Suffield oil production)
- Strong economic returns, even at low prices

Breakeven
WCS @ ~26 USD/bbl
**IPC - Canada**

**Onion Lake Thermal Asset Overview**

- **Onion Lake Area – Operated by IPC**
  - Early life thermal project in ramp up mode
  - Four pads on production with reservoir response in line with expectation
  - Resource base supports 15,000 to 20,000 bopd for more than 20 years with 5 CAD/bbl sustaining capital

- **Management focus**
  - Maintain operational excellence
  - Execute facility optimisation to build capacity to 14,000 bopd
  - Evaluate further facility optimisation projects
  - Commence warm-up and production conversions on sustaining pad F
  - Prepare surface location for sustaining production pad D’
IPC Canada
Onion Lake Thermal Production Capacity

- Production ramp up through 2018 towards current nameplate capacity 12,000 bopd

- Production curtailed in Q4 2018 in response to high WTI-WCS differentials, now back in ramp up mode

- 2019 exit rate projected at 12,000 to 14,000 bopd

- Instantaneous steam oil ratio ~2.5 at nameplate capacity\(^{(1)}\)
  - Top quartile performance for Canadian thermal projects

\(^{(1)}\) SOR reflected during realized production plateau
Acquired 243 MMboe\(^{(1)}\) resource at very low cost
- Among the best quality reservoir + thickest pay in Blackrod

Project economics improve with well pair 3 success
- Longer wells with smart completion can reduce pre-production capex
- Produced water recycle skid further reduces cost base (Onion Lake)

Low cost opportunity to lock in further upside

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\(^{(1)}\) As at December 31, 2018, see Reader Advisory and MD&A
IPC - Canada
Blackrod Asset Overview

- **Blackrod area – Operated by IPC**
  - Amongst the best greenfield SAGD projects in Canada
  - Regulatory approval in place for 80,000 bopd multi phase project
  - Two successful stages of field piloting complete
  - 100% owned and operated

- **Management Focus**
  - Execute and put on stream 3rd pilot well pair to test longer horizontal well length and advanced completion design
  - Successful results integrated into revised commercial development plan will reduce number of well pads required to reach design rates, significantly reducing capital requirements

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**Blackrod 2nd Pilot Well Pair Performance**

- **Oil Rate**
  - 24 Month Production Plateau ~2.9 SOR

- **SOR (lb/bo)**
  - 24 Month Production Plateau ~2.9 SOR

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**Data**

- **Oil Prod. (b/d)**
  - Nov-2013
  - Feb-2014
  - May-2014
  - Aug-2014
  - Nov-2014
  - Feb-2015
  - May-2015
  - Aug-2015
  - Nov-2015
  - Feb-2016
  - May-2016
  - Aug-2016
  - Nov-2016
  - Feb-2017
  - May-2017
  - Aug-2017
  - Nov-2017
  - Feb-2018
  - May-2018
  - Aug-2018

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**Legend**

- **Oil Rate**
- **SOR**
International Petroleum Corp.
Canadian Macro Supply and Pipeline Egress

- December announcement of 325 Mbopd (8.7%) production curtailment in Alberta
  - Reduced to 250 Mbopd for February and March
  - Reduced to 225 Mbopd for April
  - Reduced to 175 Mbopd for May and June

- WCS differential 12 USD/bbl in Q1 2019 vs 39 USD/bbl in Q4 2018

Source: GMP FirstEnergy, CAPP, Alberta Energy Regulator, Company disclosure, as at March 2019
Appendix

Malaysia
IPC – Malaysia
Asset Overview

- Reservoir and operational performance ahead of expectation
- Proven track record of reserve additions
- Successful programme of high value infill wells
- Focus on near field and in field production growth

As at December 31, 2018, see Reader Advisory and MD&A
2019 Capital Programme

3 Infill wells completed (2016 & 2018)
- 2018 infills paid back in ~6 months

3 Infill wells planned for 2019 execution
- ~1 year payback
- ~30 USD/boe breakeven

Keruing exploration well planned for Q2 2019 execution

Bertam Field Gross Production

Historical

Bertam Field Gross Production

>50% of production from infill wells

28
IPC – Malaysia
A15 Location - Further Infill Opportunity

- Year on year reserves increases in A15 area
  - Water cut delayed from pre-drill expectations
  - Oil in place larger than initial expectation

- 2019 Programme
  - Landing pilot required for potential 2019 infill well

A15 Reserves

- Pre-drill
- YE 2016
- YE 2017
- YE 2018

+22%  +29%  +11%  +79%

See Reader Advisory and MD&A
2019 exploration targeting 2.7 to 15.7 MMboe\(^{(1)}\)

Potential high value tie-back to existing infrastructure

I-35 reservoir
- Reservoir presence and quality confirmed by Bertam development wells
- High permeability channel sands
- 4 way structural closure mapped on seismic
- Possible stratigraphic trap leading to higher in place volumes

2019 exploration well targets structural and stratigraphic closures

\(1\) Gross unrisked prospective resources, see Reader Advisory and MD&A as at December 31, 2018
Appendix

France
IPC - France

France Asset Overview

- **Paris and Aquitaine Basins**
  - Long life low decline assets
  - Strong reservoir performance in 2018
  - Reserve replacement ratio of 174% in 2018
  - Focus on undeveloped reserves and contingent resources

![Graph showing cumulative production and 2P reserves from 2002 to 2018](image)

+63%

**2002** | **2016** | **2017** | **2018(1)**
---|---|---|---
0 | 5 | 10 | 15
5 | 10 | 15 | 20
10 | 15 | 20 | 25
15 | 20 | 25 | 30
20 | 25 | 30 | 35
25 | 30 | 35 | 40
30 | 35 | 40 | 45
40 | 45 | 50 | 55
50 | 55 | 60 | 65

Cumulative Production
2P Reserves(1)

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As at December 31, 2018, see Reader Advisory and MD&A
IPC - France
Resource Maturation (1)

- Proven track record of resource growth

**Villeperdue West - Potential Sanction 2019**

- Technology prover for Rhetian contingent resources

**Vert-La-Gravelle - Development Opportunity**

- Requires horizontal wells to unlock potential

**Villeperdue** 3.8 MMboe
- Largest single contingent resource in France
- Villeperdue West matured to reserves in 2018

**2C Contingent Resources 15.9 MMboe (1)**

**Triassic Opportunities, 7.2 MMboe**
- Requires horizontal wells to unlock potential

1) As at December 31, 2018, see Reader Advisory and MD&A
Vert-La-Gravelle Project

- **Project Sanctioned Q4 2018**
  - Targeting unswept oil in central and southern areas
  - On track for Q2 2019 spud
  - 2 horizontal producers and 1 injector (phase 1)
  - Further upside from southern flank extension
  - 23 MEUR of facilities built and commissioned in 2014

- **Application of tried and tested technology seeks to unlock significant value**

Breakeven oil price
~43 USD/boe
IPC - France

Villeperdue West Development Overview

- **Undeveloped potential in western flank**
  - Oil-water contact extends beyond current wellstock
  - 3D seismic derisked development potential
  - Western wells have lower water cut than main field
  - Field infrastructure already in place

- **Investment decision expected during 2019**
Appendix

Financial
## International Petroleum Corp. Economic Assumptions⁽¹⁾

### Oil in USD/bbl

<table>
<thead>
<tr>
<th></th>
<th>Low Case</th>
<th>Base Case</th>
<th>High Case</th>
</tr>
</thead>
<tbody>
<tr>
<td>Brent</td>
<td>50</td>
<td>60</td>
<td>70</td>
</tr>
<tr>
<td>WTI</td>
<td>44</td>
<td>52</td>
<td>60</td>
</tr>
<tr>
<td>WCS (-20 USD/bbl)</td>
<td>24</td>
<td>32</td>
<td>40</td>
</tr>
<tr>
<td>Realised price in Canada</td>
<td>WCS -5</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

### Gas in CAD/mcf

<table>
<thead>
<tr>
<th></th>
<th>Low Case</th>
<th>Base Case</th>
<th>High Case</th>
</tr>
</thead>
<tbody>
<tr>
<td>Empress</td>
<td>2.50</td>
<td>2.50</td>
<td>2.50</td>
</tr>
</tbody>
</table>

### Sensitivities

<table>
<thead>
<tr>
<th></th>
<th>Low Case</th>
<th>Base Case</th>
<th>High Case</th>
</tr>
</thead>
<tbody>
<tr>
<td>WTI-WCS differential (USD/bbl)</td>
<td>25</td>
<td>20</td>
<td>15</td>
</tr>
<tr>
<td>Empress gas price (CAD/mcf)</td>
<td>2.25</td>
<td>2.50</td>
<td>2.75</td>
</tr>
</tbody>
</table>

⁽¹⁾ Note that the WTI-WCS differential for Q1 2019 takes actuals into account
# International Petroleum Corp.

## Margin Netback (1) (USD/boe)

<table>
<thead>
<tr>
<th>USD/bbl</th>
<th>Average Brent oil price (WTI)</th>
<th>WTI - WCS differential (20) =&gt; WCS</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production guidance</td>
<td>46,000–50,000 boepd</td>
<td></td>
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<tr>
<td><strong>Revenue</strong></td>
<td></td>
<td></td>
</tr>
<tr>
<td></td>
<td>Low 50 (44)</td>
<td>Base 60 (52)</td>
</tr>
<tr>
<td>Cost of operations - Base</td>
<td>-9.8</td>
<td>-9.8</td>
</tr>
<tr>
<td>- Projects</td>
<td>-1.0</td>
<td>-1.0</td>
</tr>
<tr>
<td>Tariff/transportation expenses</td>
<td>-1.6</td>
<td>-1.6</td>
</tr>
<tr>
<td>Production taxes</td>
<td>-0.4</td>
<td>-0.5</td>
</tr>
<tr>
<td><strong>Operating costs (2)</strong></td>
<td><strong>-12.8</strong></td>
<td><strong>-12.9</strong></td>
</tr>
<tr>
<td>Cost of blending</td>
<td>-1.1</td>
<td>-1.3</td>
</tr>
<tr>
<td>Change in inventory position</td>
<td>0.3</td>
<td>0.3</td>
</tr>
<tr>
<td><strong>Cash Margin Netback</strong></td>
<td><strong>9.4</strong></td>
<td><strong>13.3</strong></td>
</tr>
</tbody>
</table>

## 2019 Forecast

<table>
<thead>
<tr>
<th>2019 Forecast</th>
</tr>
</thead>
<tbody>
<tr>
<td>Low 50 (44)</td>
</tr>
<tr>
<td>WTI - WCS differential (20) =&gt; WCS</td>
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<tr>
<td>Average Brent oil price (WTI)</td>
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</table>

## 2018 Actual

<table>
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<th>2018 Actual</th>
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<tbody>
<tr>
<td>Production guidance</td>
</tr>
<tr>
<td><strong>Revenue</strong></td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td>Cost of operations - Base</td>
</tr>
<tr>
<td>- Projects</td>
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<td>Change in inventory position</td>
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<tr>
<td><strong>Cash Margin Netback</strong></td>
</tr>
</tbody>
</table>

## Notes

1. See Reader Advisory
2. Non-IFRS measure, see Reader Advisory and MD&A
### International Petroleum Corp.

#### Operating Cash Flow\(^{(1)}\) and EBITDA Netback\(^{(2)}\) (USD/boe)

<table>
<thead>
<tr>
<th></th>
<th>2019 Forecast</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Brent oil price (USD/bbl)</strong></td>
<td>50</td>
</tr>
<tr>
<td>Cash Margin Netback</td>
<td>9.4</td>
</tr>
<tr>
<td>Cash Taxes</td>
<td>–</td>
</tr>
<tr>
<td><strong>Operating Cash Flow Netback</strong></td>
<td>9.4</td>
</tr>
<tr>
<td><strong>EBITDA Netback</strong></td>
<td>8.6</td>
</tr>
<tr>
<td><strong>Cash Taxes</strong></td>
<td>–</td>
</tr>
<tr>
<td><strong>Operating Cash Flow Netback</strong></td>
<td>13.3</td>
</tr>
<tr>
<td><strong>EBITDA Netback</strong></td>
<td>12.5</td>
</tr>
<tr>
<td><strong>Cash Margin Netback</strong></td>
<td>17.7</td>
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<tr>
<td><strong>Cash Taxes</strong></td>
<td>-0.1</td>
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<tr>
<td><strong>Operating Cash Flow Netback</strong></td>
<td>17.2</td>
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<tr>
<td><strong>EBITDA Netback</strong></td>
<td>16.9</td>
</tr>
<tr>
<td><strong>Cash Taxes</strong></td>
<td>-0.3</td>
</tr>
</tbody>
</table>

\(^{(1)}\) Non-IFRS measure, see Reader Advisory and MD&A. At mid-point of 2019 production guidance

\(^{(2)}\) See Reader Advisory and MD&A
<table>
<thead>
<tr>
<th>Brent oil price (USD/bbl)</th>
<th>2019 Forecast</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>50</td>
</tr>
<tr>
<td>Cash Margin Netback</td>
<td>9.4</td>
</tr>
<tr>
<td>Depletion/Depreciation</td>
<td>-9.2</td>
</tr>
<tr>
<td>G&amp;A</td>
<td>-0.8</td>
</tr>
<tr>
<td>Financial items, net</td>
<td>-1.9</td>
</tr>
<tr>
<td><strong>Profit/loss Before Tax</strong></td>
<td>-2.5</td>
</tr>
<tr>
<td>Tax</td>
<td>1.4</td>
</tr>
<tr>
<td><strong>Net Profit</strong></td>
<td>-1.1</td>
</tr>
</tbody>
</table>

*(1) See Reader Advisory and MD&A*
### International Petroleum Corp.

**Oil Sensitivity to WTI/WCS Differential**

<table>
<thead>
<tr>
<th>Brent oil price (USD/bbl)</th>
<th>WTI/WCS Differential (USD/bbl)</th>
<th>Total Revenue (USD/boe)</th>
<th>Operating Cash Flow&lt;sup&gt;(1)&lt;/sup&gt; (USD/boe)</th>
<th>EBITDA&lt;sup&gt;(1)&lt;/sup&gt; (USD/boe)</th>
<th>Difference</th>
</tr>
</thead>
<tbody>
<tr>
<td>60.00</td>
<td>25.00</td>
<td>25.7</td>
<td>11.7</td>
<td>11.1</td>
<td>± 1.5</td>
</tr>
<tr>
<td>60.00</td>
<td>20.00</td>
<td>27.2</td>
<td>13.2</td>
<td>12.6</td>
<td>± 1.5</td>
</tr>
<tr>
<td>60.00</td>
<td>15.00</td>
<td>28.7</td>
<td>14.7</td>
<td>14.1</td>
<td>± 1.5</td>
</tr>
</tbody>
</table>

**2019 Forecast**

- Same difference applies when differential changes by 5 USD/bbl at Brent prices of 50 or 70 USD/bbl

<sup>(1)</sup> Non-IFRS measure, see Reader Advisory and MD&A
### International Petroleum Corp.

**Gas Sensitivity to Realised Canadian Gas Price**

<table>
<thead>
<tr>
<th></th>
<th>2019 Forecast</th>
<th>Base Case</th>
<th>Difference</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Brent oil price (USD/bbl)</strong></td>
<td>60.00</td>
<td>60.00</td>
<td>± 0.4</td>
</tr>
<tr>
<td><strong>WTI/WCS Differential (USD/bbl)</strong></td>
<td>20.00</td>
<td>20.00</td>
<td>± 0.4</td>
</tr>
<tr>
<td><strong>Gas price (CAD/mcf)</strong></td>
<td>2.25</td>
<td>2.50</td>
<td>± 0.4</td>
</tr>
<tr>
<td><strong>Total Revenue (USD/boe)</strong></td>
<td>26.8</td>
<td>27.2</td>
<td>27.6</td>
</tr>
<tr>
<td><strong>Operating Cash Flow (1) (USD/boe)</strong></td>
<td>12.9</td>
<td>13.2</td>
<td>13.6</td>
</tr>
<tr>
<td><strong>EBITDA (1) (USD/boe)</strong></td>
<td>12.2</td>
<td>12.6</td>
<td>13.0</td>
</tr>
</tbody>
</table>

*Non-IFRS measure, see Reader Advisory and MD&A*
## International Petroleum Corp.
### Liquidity and Funding (USD/boe)

<table>
<thead>
<tr>
<th>Brent oil price (USD/bbl)</th>
<th>50</th>
<th>60 (Base)</th>
<th>70</th>
</tr>
</thead>
<tbody>
<tr>
<td>Operating Cash Flow Netback</td>
<td>9.4</td>
<td>13.2</td>
<td>17.4</td>
</tr>
<tr>
<td>General and Administration Costs</td>
<td>-0.8</td>
<td>-0.8</td>
<td>-0.8</td>
</tr>
<tr>
<td>Cash Financial Items</td>
<td>-1.2</td>
<td>-1.1</td>
<td>-1.0</td>
</tr>
<tr>
<td>Cash Flow Available for Investment</td>
<td>7.4</td>
<td>11.3</td>
<td>15.6</td>
</tr>
</tbody>
</table>

| Development Capex | 7.7 | 7.7 | 7.7 |
| Exploration & Appraisal Capex | 1.5 | 1.5 | 1.4 |
| Working Cap. (incl. decommissioning) | 1.1 | 1.4 | 2.2 |
| **Total** | **10.3** | **10.6** | **11.3** |

| Free Cash Flow | -2.9 | 0.7 | 4.3 |

| Anticipated Liquidity from existing Credit Facilities | 9.6 | 9.6 | 9.6 |
| Liquidity Headroom at end of 2019 | 6.7 | 10.3 | 13.9 |
International Petroleum Corp.

Brent Price (1)

Price Decks Brent USD/bbl (1)

(1) See Reader Advisory and MD&A
International Petroleum Corp.

Canadian Pricing \(^{(1)}\)

\(^{(1)}\) See Reader Advisory and MD&A
Appendix

Financial

First Quarter 2019 Highlights
### First Quarter 2019

#### Financial Highlights

<table>
<thead>
<tr>
<th></th>
<th>First Quarter 2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>Production (boepd)</td>
<td>44,400</td>
</tr>
<tr>
<td>Average Dated Brent Oil Price (USD/boe)</td>
<td>63.1</td>
</tr>
<tr>
<td>Operating costs (USD/boe)</td>
<td>13.2</td>
</tr>
<tr>
<td>Operating cash flow (MUSD)</td>
<td>83.1</td>
</tr>
<tr>
<td>EBITDA (MUSD)</td>
<td>81.7</td>
</tr>
<tr>
<td>Net result (MUSD)</td>
<td>33.1</td>
</tr>
</tbody>
</table>

*¹ Non-IFRS Measure, see MD&A*
First Quarter 2019
Realised Oil Prices

<table>
<thead>
<tr>
<th>Country</th>
<th>Price (USD/bbl)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Malaysia</td>
<td>67.72</td>
</tr>
<tr>
<td>France</td>
<td>64.50</td>
</tr>
<tr>
<td>Suffield</td>
<td>45.85</td>
</tr>
<tr>
<td>Onion Lake</td>
<td>37.20</td>
</tr>
</tbody>
</table>

USD/bbl

- WTI
- WTI - 10 days differential (month -1)
- Brent
First Quarter 2019
Realised Gas Prices

<table>
<thead>
<tr>
<th>Month</th>
<th>Empress / AECO differential</th>
<th>Realised Price CAD/Mcf</th>
</tr>
</thead>
<tbody>
<tr>
<td>Jan 2018</td>
<td>2.70</td>
<td>2.29</td>
</tr>
<tr>
<td>Feb 2018</td>
<td>2.11</td>
<td>3.07</td>
</tr>
<tr>
<td>Mar 2018</td>
<td>2.29</td>
<td>3.86</td>
</tr>
<tr>
<td>Apr 2019</td>
<td>3.07</td>
<td></td>
</tr>
<tr>
<td>May 2019</td>
<td>3.86</td>
<td></td>
</tr>
</tbody>
</table>
First Quarter 2019

Netback \(^{(1)}\) (USD/boe)

<table>
<thead>
<tr>
<th>Average Dated Brent oil price</th>
<th>First Quarter 2019</th>
</tr>
</thead>
<tbody>
<tr>
<td>Revenue</td>
<td>36.9</td>
</tr>
<tr>
<td>Cost of operations</td>
<td>-11.3</td>
</tr>
<tr>
<td>Tariff and transportation</td>
<td>-1.5</td>
</tr>
<tr>
<td>Production taxes</td>
<td>-0.4</td>
</tr>
<tr>
<td>Operating costs (^{(2)})</td>
<td>-13.2</td>
</tr>
<tr>
<td>Cost of blending</td>
<td>-1.4</td>
</tr>
<tr>
<td>Inventory movements</td>
<td>-1.1</td>
</tr>
<tr>
<td><strong>Revenue – production costs</strong></td>
<td><strong>21.2</strong></td>
</tr>
<tr>
<td>Cash taxes</td>
<td>-0.4</td>
</tr>
<tr>
<td><strong>Operating cash flow</strong> (^{(2)})</td>
<td><strong>20.8</strong></td>
</tr>
<tr>
<td>General and administration costs (^{(3)})</td>
<td>-0.7</td>
</tr>
<tr>
<td><strong>EBITDA</strong> (^{(2)})</td>
<td><strong>20.5</strong></td>
</tr>
</tbody>
</table>

\(^{(1)}\) Based on production volumes  \(^{(2)}\) Non-IFRS Measure, see MD&A  \(^{(3)}\) Adjusted for depreciation
First Quarter 2019
Cash Flows and Closing Net Debt\(^{(1)}\) (MUSD)

\[\text{Opening Net Debt} \quad 1 \text{ Jan 2019} \quad \text{MUSD} -276.8\]

\[\text{Operating Cash Flow} \quad \text{MUSD} 83.1\]

\[\text{Exploration \\& evaluation} \quad \text{MUSD} -2.6\]

\[\text{Development} \quad \text{MUSD} -19.3\]

\[\text{Financial} \quad \text{MUSD} -4.7\]

\[\text{G\\&A} \quad \text{MUSD} -3.0\]

\[\text{Working capital \\& other} \quad \text{MUSD} -33.7\]

\[\text{Closing Net Debt} \quad 31 \text{ Mar 2019} \quad \text{MUSD} -257.0\]

\(\text{(1)}\) Non-IFRS Measure, see MD&A
First Quarter 2019

Liquidity and Hedging

- **Credit Facilities**
  - One International (200 MUSD) and two Canadian (200 and 120 MCAD) revolving credit facilities
  - IPC intends to amalgamate the two Canadian credit facilities into a single one for greater flexibility in Q2
  - Second lien notes (75 MCAD)
  - In excess of 150 MUSD availability under revolving credit lines

- **Hedging**
  - 20 to 50% of former BlackPearl production volumes
  - Maturity up to end June 2020
  - Mostly using collars
Forward Looking Statements
This presentation contains statements and information which constitute "forward-looking statements" or "forward-looking information" (within the meaning of applicable securities legislation). Such statements and information (together, "forward-looking statements") relate to future events, including the Corporation's future performance, business prospects or opportunities. Actual results may differ materially from those expressed or implied by forward-looking statements. The forward-looking statements contained in this presentation are expressly qualified by this cautionary statement. Forward-looking statements speak only as of the date of this presentation, unless otherwise indicated. IPC does not intend, and does not assume any obligation, to update these forward-looking statements, except as required by applicable laws.

All statements other than statements of historical fact may be forward-looking statements. Any statements that express or involve discussions with respect to predictions, expectations, beliefs, plans, projections, forecasts, guidance, budgets, objectives, assumptions or future events or performance (often, but not always, using words or phrases such as "anticipate" "believe" "can" "could" "estimate" "expect" "intend" "may" "might" "plan" "potential" "project" "predict" "target" "should" "will" "would" or similar expressions) are not statements of historical fact and may be "forward-looking statements". Forward-looking statements include, but are not limited to, statements with respect to: IPC’s intention and ability to continue to implement strategies to build long-term shareholder value; IPC’s intention to review further drilling opportunities, including the acquisition of any of the blocks of assets to provide a solid foundation for organic and inorganic growth; the continued facility uptime and reservoir performance in IPC’s areas of operation; the proposed Vert LoGravelle development project, including drilling, and other organic growth opportunities in France, including the Villiperdue West project; the status of the suspension of operations at the Grandpuits refinery; and the related effects on production and sales, in France; the proposed third phase of infill drilling in Malaysia and the ability to mature additional locations, and the production uplift from such drilling; the proposed drilling of the Kening prospect in Malaysia and the development options if drilling is successful; future development potential of the Suffield area operations, including continued and future oil field drilling and gas optimization programs and the NDN EDAP development project; drilling the proposed commercial oil field drilling in Canada, including the ability of such drilling to identify further drilling or development opportunities; future development of the Blackpad project, including the land position acquired in May 2019, in Canada; the results of the facility optimization program and the work to debottleneck the facilities and injection capability, as well as water intake issues, at the Onion Lake Thermal; the ability to integrate the assets and operations acquired in the BlackPearl acquisition, including the ability to accelerate value creation and extend IPC’s reserves life following such acquisition; 2019 production range, exit rate, operating costs and capital expenditure estimates; potential future acquisition opportunities; estimates of reserves; estimates of contingent resources; estimates of prospective resources; the ability to generate free cash flows and use cash that may be generated from debt and to continue to deleverage; and future drilling and other exploration and development activities.

Statements relating to "reserves"; "contingent resources" and "prospective resources", as defined in the Canadian Oil and Gas Evaluation Handbook, are forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions, that the reserves and resources described exist in the quantities predicted or estimated and that the reserves and resources can be profitably produced in the future. Ultimate recovery of reserves or resources is based on forecasts of future results, estimates of amounts not yet determinable and assumptions of management.

The forward-looking statements are based on certain key expectations and assumptions made by IPC, including expectations and assumptions concerning: prevailing commodity prices and currency exchange rates; applicable royalty rates and tax laws; interest rates; future well production rates and reserve and contingent resource volumes; operating costs; the timing of receipt of regulatory approvals; the performance of existing wells; the success obtained in drilling new wells; anticipated timing and results of capital expenditures; the sufficiency of budgeted capital expenditures in carrying out planned activities; the timing, location and extent of future drilling operations; the successful completion of acquisitions and dispositions; the benefits of acquisitions; the state of the economy and the exploration and production business in the jurisdictions in which IPC operates and globally; the availability and cost of financing, labour and services; and the ability to market crude oil, natural gas and natural gas liquids successively.

While IPC believes that the expectations and assumptions on which such forward-looking statements are based are reasonable, undue reliance should not be placed on the forward-looking statements because IPC can give no assurances that they will prove to be correct. Since forward-looking statements address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to: the risks associated with obtaining and retaining oil and gas leases in general such as operational risks in development, exploration and production; delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of estimates and projections relating to reserves, resources, production, revenues, costs and expenses; health, safety and environmental risks; commodity price and exchange rate fluctuations; interest rate fluctuations; marketing and transportation; loss of markets; environmental risks; competition; incorrect assessment of the value of acquisitions; failure to complete or realize the anticipated benefits of acquisitions or dispositions; the ability to access sufficient capital from internal and external sources; failure to obtain required regulatory and other approvals; and changes in legislation, including but not limited to tax laws, royalties and environmental regulations. Readers are cautioned that the foregoing list of factors is not exhaustive.

Additional information on these and other factors that can affect IPC, or its operations, is available in the management discussion and analysis included in the three months ended March 31, 2019 (MD&A) (See “Cautionary Statement Regarding Forward-Looking Information” therein), the Corporation’s Annual Information Form (AIF) for the year ended December 31, 2018 (See “Cautionary Statement Regarding Forward-Looking Information,” “Reserves and Resources Advisory” and “Risk Factors” therein) and other reports on file with applicable securities regulatory authorities, which may be accessed through the SEDAR website (www.sedar.com) or IPC’s website (www.international-petroleum.com).

Non(IFRS) Measures
The Corporation has presented in this press release certain non-IFRS measures, including “operating cash flow,” “Earnings Before Interest, Tax, Depreciation and Amortization” (EBITDA), “operating costs” and “net debt/net cash”, which are not generally accepted accounting measures under International Financial Reporting Standards (IFRS) and do not have any standardized meaning prescribed by IFRS and, therefore, may not be comparable to similar measures presented by other public companies. Non-IFRS measures should not be considered in isolation or as a substitute for measures prepared in accordance with IFRS.

Management believes that EBITDA, operating costs and net debt/net cash are useful supplemental measures that may assist shareholders in the analysis of the cash generated by and the financial performance and position of the Corporation. The Corporation also uses non-IFRS measures internally in order to facilitate operating performance comparisons from period to period, prepare annual operating budgets and assess the Corporation’s ability to meet its future capital expenditure and working capital requirements. Management believes these non-IFRS measures are important supplemental financial measures on a basis that is more consistent and comparable between reporting periods. The Corporation also believes that securities analysts, investors and other interested parties frequently use non-IFRS measures in the evaluation of the Corporation's operating performance and financial condition on a basis that is more consistent and comparable between periods.

The forward-looking statements are based on certain key expectations and assumptions made by IPC, including expectations and assumptions concerning: prevailing commodity prices and currency exchange rates; applicable royalty rates and tax laws; interest rates; future well production rates and reserve and contingent resource volumes; operating costs; the timing of receipt of regulatory approvals; the performance of existing wells; the success obtained in drilling new wells; anticipated timing and results of capital expenditures; and sufficient capital expenditures in carrying out planned activities; the timing, location and extent of future drilling operations; the successful completion of acquisitions and dispositions; the benefits of acquisitions; the state of the economy and the exploration and production business in the jurisdictions in which IPC operates and globally; the availability and cost of financing, labour and services; and the ability to market crude oil, natural gas and natural gas liquids successively.

The definition and reconciliation of each non-IFRS measure is presented in IPC's MD&A (See “Non-IFRS Measures” therein), the Corporation's Annual Information Form (AIF) for the year ended December 31, 2018 (See “Cautionary Statement Regarding Forward-Looking Information,” “Reserves and Resources Advisory” and “Risk Factors” therein) and other reports on file with applicable securities regulatory authorities, which may be accessed through the SEDAR website (www.sedar.com) or IPC’s website (www.international-petroleum.com).

Disclosure of Oil and Gas Information
This presentation contains references to estimates of 2P reserves and resources attributed to the Corporation’s oil and gas assets. Gross reserves / resources are the total working interest (operating or non-operating) share reserves before the deduction of any royalties and without including any royalty interests receivable.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC's oil and gas assets contributed to the Corporation's oil and gas assets. Gross reserves / resources are the total working interest (operating or non-operating) share reserves before the deduction of any royalties and without including any royalty interests receivable.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC’s oil and gas assets in the Onion Lake, Blackrod and Mooney areas in Canada are effective as of December 31, 2018, and are included in the report prepared by McDaniel & Associates Consultants Ltd. (McDaniel), an independent qualified reserves evaluator, in accordance with National Instrument 81-101 – Standards of Disclosure for Oil and Gas Activities (NI 81-101) and the Canadian Oil and Gas Evaluation Handbook (the COGE Handbook), and using McDaniel’s January 1, 2019 price forecasts.

Reserves estimates, contingent resource estimates and estimates of future net revenue in respect of IPC’s oil and gas assets in France and Malaysia are effective as of December 31, 2018, and are included in the report prepared by ERC Equipe Logicielle (ERCE), an independent qualified reserves auditor, in accordance with NI 81-101 and the COGE Handbook, and using McDaniel’s January 1, 2019 price forecasts.

Reserves estimates, contingent resource estimates, prospective resource estimates and estimates of future net revenue in respect of IPC’s oil and gas assets in France and Malaysia are effective as of December 31, 2018, and are included in the report prepared by ERC Equipe Logicielle (ERCE), an independent qualified reserves auditor, in accordance with NI 81-101 and the COGE Handbook, and using McDaniel’s January 1, 2019 price forecasts.
The contingent resource estimates in respect of the oil and gas assets acquired in May 2019 in the Blackrod area of Canada are effective as of December 31, 2018, and have been evaluated by Sproule, in accordance with NI 51-101 and the COGE Handbook. The lands acquired will be part of the planned SAGD development at Blackrod and have the same classification (Development on Hold) as the other Blackrod lands. The same chance of development risk (77%) has been applied to the acquired lands as was used for Phase 2 and Phase 3 of the Blackrod project. These lands will be incorporated into the Phase 2 and Phase 3 development plan going forward. Additional details regarding the planned development at Blackrod, including an assessment of the contingencies, timing and economics for the proposed development, are available in the AIF.

The price forecasts used in the reserve reports are available on the website of McDaniel (www.mcdan.com), and are contained in the MCR.

The reserves life index (RLI) is calculated by dividing the 2P reserves of 288 MMboe as at December 31, 2018, by the mid-point of the initial 2019 production guidance of 46,000 to 50,800 boepd. The reserves replacement ratio is based on 2P reserves of 129.1 MMboe as at December 31, 2017 (including the 2P reserves attributable to the acquisition of the Suffield area assets which completed on January 5, 2018); production during 2018 of 124.4 MMboe; additions to 2P reserves during 2018 of 12.3 MMboe; disposals of 2P reserves related to the disposal of the Nethersol assets of 1.6 MMboe and 2P reserves of 128.0 MMboe as at December 31, 2018 (excluding the 2P reserves attributable to the acquisition of BlackPearl which completed on December 14, 2018).

"2P reserves" means IPC's gross proved plus probable reserves. "Proved reserves" are those reserves that 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. "Probable reserves" are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Contingent resources are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more contingencies. Contingencies are conditions that must be satisfied for a portion of contingent resources to be classified as reserves that are: (a) specific to the project being evaluated; and (b) expected to be resolved within a reasonable timeframe. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. Contingent resources are further classified in accordance with the level of certainty associated with the estimates and may be sub-classified based on a project maturity and/or characterized by their economic status.

There are three classifications of contingent resources: low estimate, best estimate and high estimate. Best estimate is a classification of estimated quantities of recoverable resources described in the COGE Handbook as being considered to be the best estimate of the quantity that will be actually recovered. It is equally likely that the actual remaining quantities recovered will be greater or less than the best estimate. If probabilistic methods are used, there should be at least a 50% probability that the quantities actually recovered will equal or exceed the best estimate.

Contingent resources are further classified based on project maturity. The project maturity subclasses include development pending, development on hold, development unclarified and development not viable. All of the Corporation’s contingent resources are classified as either development on hold or development unclarified. Development on hold is defined as a contingent resource where there is a reasonable chance of development, but there are major non-technical contingencies to be resolved that are usually beyond the control of the operator.

Development unclarified is defined as a contingent resource that requires further appraisal to clarify the potential for development and has been assigned a lower chance of development until contingencies can be clearly defined. Chance of development is the probability of a project being commercially viable.

References to “unrisked” contingent resource volumes means that the reported volumes of contingent resource have not been risked (or adjusted) based on the chance of commerciality of such resources. In accordance with the COGE Handbook for contingent resources, the chance of commerciality is solely based on the chance of development based on all contingencies required for the re-classification of the contingent resources as reserves being resolved. Therefore unrisked reported volumes of contingent resources do not reflect the risking (or adjustment) of such volumes based on the chance of development of such resources.

The contingent resources reported in this presentation are estimates only. The estimates are based upon a number of factors and assumptions each of which contains estimation error which could result in future revisions of the estimates as more technical and commercial information becomes available. The estimation factors include, but not be limited to, the mapped extent of the oil and gas accumulations, geologic characteristics of the reservoirs, and dynamic reservoir performance. There are numerous risks and uncertainties associated with recovery of such resources, including many factors beyond the Corporation’s control. There is uncertainty that it will be commercially viable to produce any portion of the contingent resources referred to in this presentation.

2P reserves and contingent resources included in the reports of McDaniel, Sproule and ERCE have been aggregated in this presentation by IPC. Estimates of reserves, resources and future net revenue for individual properties may not reflect the same level of confidence as estimates of reserves, resources and future net revenue for all properties, due to aggregation. This presentation contains estimates of the net present value of the future net revenue from IPC’s reserves. The estimated values of future net revenue disclosed in this presentation do not represent fair market value. There is no assurance that the forecast prices and cost assumptions used in the reserve evaluations will be attained and variances could be material.

References to “contingent resources” do not constitute, and should be distinguished from, references to “reserves”. References to “prospective resources” do not constitute, and should be distinguished from, references to “contingent resources” and “reserves”.

This presentation includes oil and gas metrics including “cash margin netback”, “taxation netback”, “operating cash flow netback”, “cash taxes”, “EBITDA netback” and “profit netback”. Such metrics do not have a standardized meaning under IFRS or otherwise, and as such may not be reliable. This information should not be used to make comparisons.

"Cash margin netback" is calculated on a per boe basis as oil and gas sales, less operating, tariff/transportation and production tax expenses. Netback is a common metric used in the oil and gas industry and is used by management to measure operating results on a per boe basis to better analyze performance against prior periods on a comparable basis.

"Taxation netback" is calculated on a per boe basis as current tax charge/credit less deferred tax charge/credit. Taxation netback is used to measure taxation on a per boe basis.

"Operating cash flow netback" is calculated as cash margin netback less cash taxes. Operating cash flow netback is used to measure operating results on a per boe basis of cash flow.

"Cash taxes" is calculated as taxes payable in cash, and not only for accounting purposes. Cash taxes is used to measure cash flow.

"EBITDA netback" is calculated as cash margin netback less general and administration expenses. EBITDA netback is used by management to measure operating results on a per boe basis.

"Profit netback" is calculated as cash margin netback less depletion/depreciation, general and administration expenses and financial items. Profit netback is used by management to measure operating results on a per boe basis.

BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 thousand cubic feet (Mcf) per 1 barrel (bbl) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. As the value ratio between natural gas and crude oil based on the current prices of natural gas and crude oil is significantly different from the energy equivalency of 6:1, utilizing a 6:1 conversion basis may be misleading as an indication of value.

Currency

All dollar amounts in this presentation are expressed in United States dollars, except where otherwise noted. References herein to USD mean United States dollars. References herein to CAD mean Canadian dollars.