Corporate Presentation

May 2019

TSX : IPO
OTCQX : IPOOF
Forward Looking Statements and Oil and Gas Advisories

This presentation contains certain forward-looking information and statements within the meaning of applicable securities laws. The use of any of the words “expect,” “anticipate,” “continue,” “estimate,” “may,” “will,” “project,” “should,” “believe,” “plans,” “intends” and similar expressions are intended to identify forward-looking information or statements. In particular, but without limiting the forgoing, this presentation contains forward-looking information and statements pertaining to the following: business strategy and objectives of InPlay Oil Corp. (“InPlay”), volumes and estimated value of InPlay’s oil and gas reserves; the volume of InPlay’s oil and gas production; future production estimates and targets; production decline profiles; future oil and natural gas prices; future liquidity and financial capacity; future results from operations and operating metrics; future costs, expenses and royalty rates; future cash flows; future interest costs; forecast net debt; target debt to cash flow ratios; the exchange rate between the US$ and CDN$; future development, exploration, acquisition and development activities and related capital expenditures and internal projections and forecasts; estimated drilling locations; the amount and timing of capital projects; operating costs; forecasts of operating and cash flow netbacks; and the total future capital associated with development of reserves and resources.

The recovery and reserve estimates of InPlay’s reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Throughout this presentation various references are made to “potential” and “targeted” resource and recoveries which have been prepared by management of InPlay and are not estimates of reserves or resources. Accordingly, undue reliance should not be placed on same. Such information has been prepared by management for the purposes of making capital investment decisions and for internal budget preparation only. In addition, forward-looking statements or information are based on a number of material factors, expectations or assumptions of InPlay which have been used to develop such statements and information but which may prove to be incorrect. Although InPlay believes that the expectations reflected in such forward-looking statements or information are reasonable, undue reliance should not be placed on forward-looking statements because InPlay can give no assurance that such expectations will prove to be correct. In addition to other factors and assumptions which may be identified herein, assumptions have been made regarding, among other things: the impact of increasing competition; the general stability of the economic and political environment in which InPlay operates; the timely receipt of any required regulatory approvals; the ability of InPlay to obtain qualified staff, equipment and services in a timely and cost efficient manner; the ability of InPlay to add production and reserves through acquisition, development and exploration activities; drilling results; the ability of the operator of the projects in which InPlay has an interest to in operate the field in a safe, efficient and effective manner; field production rates and decline rates; the ability to replace and expand oil and natural gas reserves through acquisition, development and exploration; risks associated with the degree of certainty in resource assessments; the timing and cost of pipeline, storage and facility construction and expansion and the ability of InPlay to secure adequate product transportation; future commodity prices; currency, exchange and interest rates; regulatory framework regarding royalties, taxes and environmental matters in the jurisdictions in which InPlay operates; and the ability of InPlay to successfully market its oil and natural gas products.

The forward-looking information and statements included in this presentation are not guarantees of future performance and should not be unduly relied upon. Such information and statements; including the assumptions made in respect thereof, involve known and unknown risks, uncertainties and other factors that may cause actual results or events to diverge materially from those anticipated in such forward-looking information or statements including, without limitation: changes in commodity prices; changes in the demand for or supply of InPlay’s products; unanticipated operating results or production declines; changes in tax or environmental laws, royalty rates or other regulatory matters; changes in development plans of InPlay or by third party operators of InPlay’s properties, increased debt levels or debt service requirements; inaccurate estimation of InPlay’s oil and gas reserve and resource volumes; limited, unfavourable or a lack of access to capital markets; increased costs; a lack of inadequate insurance coverage; the impact of competitors; and certain other risks detailed from time-to-time in InPlay’s disclosure documents.

InPlay’s 2019 budget guidance and related targets and forecasts disclosed herein are best estimates based on certain assumptions including, without limitation, operating results, known fiscal regimes, commodity prices and risk management contracts and will be regularly monitored by management. Our objective will be to proactively manage our capital program as it relates to operational success and fluctuating commodity prices with a priority to maintain financial flexibility and achieve our production guidance. InPlay will closely monitor the budget and financial situation throughout the year to assess market conditions and will quickly adjust budget levels or pace of development in accordance with commodity prices and available funds from operations.

The forward-looking information and statements contained in this presentation speak only as of the date of this presentation, and InPlay does not assume any obligation to publicly update or revise any of the included forward-looking statements or information, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Certain information in this document may constitute “analogous information” as defined in National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities (“NI-51-101”), including but not limited to, information relating to the areas in geographical proximity to lands that are or may be held by InPlay. Such information has been obtained from government sources, regulatory agencies or other industry participants. InPlay believes the information is relevant as it helps to define the reservoir characteristics in which InPlay may hold an interest. InPlay is unable to confirm that the analogous information was prepared by a qualified reserves evaluator or auditor. Such information is not an estimate of the reserves or resources attributable to lands held or potentially to be held by InPlay and there is no certainty that the reservoir data and economics information for the lands held or potentially to be held by InPlay will be similar to the information presented herein. The reader is cautioned that the data relied upon by InPlay may be in error and/or may not be analogous to such lands to be held by InPlay.

Any references in this presentation to initial, early and/or test or production/performace rates are useful in confirming the presence of hydrocarbons, however, such rates are not determinate of the rates at which such wells will produce or continue production and to decline thereafter. Additionally, such rates may also include recovered “load oil” fluid used in well completion stimulation. Readers are cautioned not to place reliance on such rates in calculating the aggregate production for InPlay. The initial production rate may be estimated based on other third-party estimates or limited data available at this time. In all cases in this presentation, initial production or tests are not necessarily indicative of long-term performance of the relevant well or fields or of ultimate recovery of hydrocarbons.

The information contained in this corporate presentation does not purport to be all-inclusive or to contain all information that a prospective investor may require. Prospective investors are encouraged to conduct their own analysis and reviews of InPlay and of the information contained in this corporate presentation. Without limitation, prospective investors should consider the advice of their financial, legal, accounting, tax and other advisors and such other factors they consider appropriate in investigating and analyzing InPlay.

Any financial outlook or future-oriented financial information, as defined by applicable securities legislation, has been approved by management of InPlay. Such financial outlook or future-oriented financial information is provided for the purpose of providing information about management's current expectations and plans relating to the future. Readers are cautioned that reliance on such information may not be appropriate for other purposes.

In this presentation, certain terms that are not specifically defined in International Financial Reporting Standards (“IFRS”) are used to analyze the Company’s future operating results. Management believes that certain measures not recognized under IFRS assist management and the reader in assessing the Company’s expected performance and understanding the Company’s outlook. These measures provide the reader with additional insight into the Company’s performance. However, these terms do not have any standardized meanings prescribed by IFRS and therefore may not be comparable with the calculations of similar measures for other entities. Please refer to the “Non-GAAP” Measures section of the Company’s most recently filed Management’s Discussion and Analysis and the most recent press release for the description and definition of those measures.
Investment Highlights

• 2018 saw a continued transformation of the Company into focused premium growth assets
  – Grew oil and liquids production 22% in 2018 over 2017
  – Sold non-core facility and non-core assets for $26.6 million
  – Purchased Willesden Green Cardium assets for $5.5 million
  – Increased Crown land position in East Basin Duvernay shale oil play by 34%
  – Increased production guidance twice even with selling 250 boe/d and deferring completion of two Hz wells

• 2019 Forecast – top tier light oil growth
  – 10% - 14% organic light oil and liquids exit growth over 2018
  – 6% - 10% organic light oil and liquids annual growth over 2018
  – Free cash flow of $5 - $8mm provides flexibility and optionality
  – Operating income profit margins expected to increase 12% with WTI forecasted to be lower by US$ 4.50 per bbl

• Positioned in two of the most exciting light oil plays in the Western Canada Sedimentary Basin
  – Bioturbated Cardium light oil play
  – High impact shallow East Basin Duvernay light oil play

• Operational expertise drives top quartile capital efficiencies and growth
  – PDP Finding, Development and Acquisition cost of $9.49 in 2018
  – Capital efficiency of $14,770 per boed in 2018
  – Light oil drilling program with <1.0 year payouts at current commodity prices

• Sustainable and financially strong
  – ~245 Cardium and Belly River development locations (>27 years inventory at 9 wells per year)
  – Reserve Life Index (RLI) of 15.9 years; Base decline of 24.5% in 2019

(1) Based on current 2019 forecast
## Financial Highlights

<table>
<thead>
<tr>
<th></th>
<th>Q1 '19</th>
<th>Q1 '18</th>
<th>%</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Production (boed)&lt;sup&gt;(1)&lt;/sup&gt;</td>
<td>4,737</td>
<td>4,415</td>
<td>7</td>
</tr>
<tr>
<td>Adjusted Funds flow ($000s)</td>
<td>9,054</td>
<td>7,939</td>
<td>14</td>
</tr>
<tr>
<td>Adjusted Funds flow per share ($)</td>
<td>0.13</td>
<td>0.12</td>
<td>8</td>
</tr>
<tr>
<td>Revenue ($/boe)</td>
<td>45.06</td>
<td>50.11</td>
<td>(10)</td>
</tr>
<tr>
<td>Operating Netback ($/boe)</td>
<td>26.35</td>
<td>28.33</td>
<td>(7)</td>
</tr>
<tr>
<td>Operating costs ($/boe)</td>
<td>14.29</td>
<td>15.98</td>
<td>(11)</td>
</tr>
<tr>
<td>E&amp;D Capital spending ($000s)&lt;sup&gt;(2)&lt;/sup&gt;</td>
<td>14,763</td>
<td>13,546</td>
<td>9</td>
</tr>
<tr>
<td>Net debt ($000s)</td>
<td>60,033</td>
<td>53,407</td>
<td>12</td>
</tr>
<tr>
<td>Debt / Annualized adjusted funds flow&lt;sup&gt;(1)&lt;/sup&gt;</td>
<td>1.7</td>
<td>1.7</td>
<td>-</td>
</tr>
<tr>
<td>Wells drilled gross / net</td>
<td>5 / 2.7</td>
<td>6 / 3.8</td>
<td>(17) / (29)</td>
</tr>
</tbody>
</table>

<sup>(1)</sup> Q1 2019 production is net of the sale of 250 boe/d of non-core producing assets in Oct 2018

<sup>(2)</sup> Includes completion capital for 2 (2.0 net) Cardium wells drilled in Q4 2018
Corporate Overview

OPERATING SUMMARY

2019 Average Production (oil & liquids weighting) 4,900-5,100 boe/d (70%)
2019 Exit Production (oil & liquids weighting) 5,400-5,600 boe/d (70%)
2019 Drilling Plans (# Hz Cardium wells) 9.0 net

Proved Reserves (1) 18,859 mboe
P+P Reserves (1) 27,063 mboe
P+P NPV10% ($mm) (1) $387.7 mm

MARKET SUMMARY

Basic Shares Outstanding (basic / FD) (mm) 68.3 / 74.6
Market Capitalization (@ $1.10 per share) (mm) $75
Enterprise Value (@ $1.10 per share) (2) (mm) $135
Liquidity (shares/day average over last 6 months) ~ 80,000
Employee & Director Ownership (diluted) 8.6%
Large Insider Shareholders (diluted) 37.7%

DEBT SUMMARY (2) ($mm)

Bank / Net Debt $50.2 / $60.0
Credit Facility $75.0

(1) As of December 31, 2018. See “Reserves” and “Net Present Value Estimates” under “Information on Reserves and Operational Information”
(2) As of March 31, 2019

73% oil & NGL in P+P reserve booking
## Reserve Highlights

<table>
<thead>
<tr>
<th></th>
<th>BOE (Mboe)</th>
<th>Value PV10% (1000’s)</th>
<th>Reserves Replacement (%)</th>
<th>RLI (Years)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proved Developed Producing + Non Producing(^{(3)})</td>
<td>8,784</td>
<td>148,644</td>
<td>140</td>
<td>5.2</td>
</tr>
<tr>
<td>Total Proved</td>
<td>18,859</td>
<td>252,454</td>
<td>182</td>
<td>11.1</td>
</tr>
<tr>
<td>Total Proved + Probable</td>
<td>27,063</td>
<td>387,682</td>
<td>158</td>
<td>15.9</td>
</tr>
</tbody>
</table>

## Finding, Development & Acquisition Costs and Recycle Ratios\(^{(4)}\)

<table>
<thead>
<tr>
<th></th>
<th>FD&amp;A ($/boe)</th>
<th>Recycle Ratio</th>
<th>Average Peer FD&amp;A ($/boe) (^{(5)})</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proved Developed Producing</td>
<td>9.49</td>
<td>2.5</td>
<td>14.52</td>
</tr>
<tr>
<td>Total Proved</td>
<td>16.94</td>
<td>1.4</td>
<td>20.88</td>
</tr>
<tr>
<td>Total Proved + Probable</td>
<td>15.96</td>
<td>1.5</td>
<td>18.12</td>
</tr>
</tbody>
</table>

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\(^{(1)}\) Inclusive of a disposition: 579 mboe (PDP), 1,817 mboe (TP), and 2,290 mboe (TPP)

\(^{(2)}\) Refer to notes in press release dated March 20, 2019 for details of these calculations

\(^{(3)}\) Includes the proved developed non-producing reserves and value from the two wells drilled in 2018 but not completed until January 2019 due to the low commodity prices seen in November and December

\(^{(4)}\) RLI Based on average 2018 production

\(^{(5)}\) Average of publically disclosed values for oil focused peers (BNE, TOG, TVE, WCP, SGY)
• Light oil & liquids growth of 22% in 2018 over 2017
• Forecast 2019 light oil & liquids exit production growth of 10% - 14% over 2018
★ Sold 250 boed (70% liquids) of non core assets at premium market valuations in October 2018

• Consistently increasing reserves year over year
• PDP, TP, TPP growth of 6%, 8% and 4% in 2018 even with disposition of 579 mboe (PDP), 1,817 mboe (TP) and 2,290 mboe (TPP)
Management

Strong Technically and Value Creators

Doug Bartole, P. Eng., ICD.D
   President and CEO, Director
Kevin Yakiwchuk, MSc., P. Geol.
   Vice President Exploration
Gordon Reese, BSc. Geol.
   Vice President Business Development
Thane Jensen, P. Eng.
   Vice President Operations
Darren Dittmer, CPA, CMA
   CFO

Directors

Experienced Industry Board

Dennis Nerland, LLB, ICD.D
Dale Shwed
Steve Nikiforuk, CA, ICD.D
Don Cowie
Craig Golinowski
Doug Bartole, P. Eng., ICD.D

Please see appendix for additional details on Management and Directors
Low Decline High Margin Operations
Focused Light Oil Producer

<table>
<thead>
<tr>
<th>Formations</th>
<th>Production (boed) (1)</th>
<th>Liquids</th>
<th>Net Drilling Inventory(2)</th>
<th>Net Drilling Inventory(2)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Willesden Green</td>
<td>3,350</td>
<td>70%</td>
<td>124</td>
<td>Cardium</td>
</tr>
<tr>
<td>Pembina</td>
<td>1,300</td>
<td>78%</td>
<td>119</td>
<td>Cardium</td>
</tr>
<tr>
<td>E. Basin Duvernay</td>
<td>50</td>
<td>100%</td>
<td>290</td>
<td>Duvernay</td>
</tr>
<tr>
<td>Other</td>
<td>300</td>
<td>44%</td>
<td>10</td>
<td>Mannville</td>
</tr>
<tr>
<td>Total</td>
<td>5,000</td>
<td>70%</td>
<td>533</td>
<td></td>
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</table>

**2019 estimated average production**

See “Drilling Locations” under “Information on Reserves and Operational Information”

Decline based on PDP from independent reserve reports; Assumes no additional drilling.

See “Reserves” under “Information on Reserves and Operational Information”.

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83% Cardium production

**Top Quartile** declines in oil weighted growth universe

- Consistently increasing corporate margins
- Anticipate 12% increase in operating income profit margins even with a forecasted drop of US$4.50 in WTI pricing

* Adjusted Funds Flow from operations corrected for gains/losses on derivative contracts
* 2019 based on current forecasts
Willesden Green Cardium

2018 Land acquisitions provided:

- **64%** Increase in Hz inventory
  - Replaced 5 years of drilling inventory
  - Consistently drilling industry pacesetter 1.5 mile horizontal wells and exceeding forecasted volumes

Production

- 3,350 boed from Cardium (70% liquids)
- 2 (2.0 net) Hz wells on in March with average IP30 895 boed (82% oil & liquids)

2018 Activity

- Drilled 11.2 net Cardium Hz wells (deferred completion of 2.0 net until Q1 ’19)

2019 Planned Drilling Activity

- Drill ~8.0 - 9.0 net Cardium horizontals

Upside Potential

- 124 net Hz Cardium locations(1)
  - Low permeability bioturbated zone being exploited with advancement of completion technologies
    - Continue to evaluate effects of well spacing, frac spacing and sand placement per frac

Land

- 39,680 (23,106 net) acres

Rapid Growth

In production since acquiring asset in Nov 2016

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(1) See “Drilling Locations” under “Information on Reserves and Operational Information”. Inventory identified as 1 mile equivalents at maximum 6 wells per section.
Willesden Green Cardium Economics\(^{(1)}\)

### 1.0 Mile Hz Type Curve Economics\(^{(2)}\)\(^{(3)}\)

<table>
<thead>
<tr>
<th>WTI</th>
<th>Fx (USD/CAD)</th>
<th>Payout (yrs)</th>
<th>IRR (%)</th>
<th>NPV 10 ($mm)</th>
<th>Yr 1 Netback(^{(1)}) (Cdn/boe)</th>
<th>F&amp;D (/boe)</th>
<th>Recycle Ratio (times)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$50</td>
<td>$0.74</td>
<td>1.3</td>
<td>78</td>
<td>2.3</td>
<td>$41.47</td>
<td>$12.69</td>
<td>3.3</td>
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<td>$60</td>
<td>$0.76</td>
<td>0.9</td>
<td>128</td>
<td>3.0</td>
<td>$48.05</td>
<td>$12.47</td>
<td>3.9</td>
</tr>
<tr>
<td>$70</td>
<td>$0.78</td>
<td>0.7</td>
<td>202</td>
<td>3.7</td>
<td>$54.30</td>
<td>$12.30</td>
<td>4.4</td>
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</table>

### 1.5 Mile Hz Type Curve Economics\(^{(2)}\)\(^{(3)}\)

<table>
<thead>
<tr>
<th>WTI</th>
<th>Fx (USD/CAD)</th>
<th>Payout (yrs)</th>
<th>IRR (%)</th>
<th>NPV 10 ($mm)</th>
<th>Yr 1 Netback(^{(1)}) (Cdn/boe)</th>
<th>F&amp;D (/boe)</th>
<th>Recycle Ratio (times)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$50</td>
<td>$0.74</td>
<td>1.1</td>
<td>100</td>
<td>3.3</td>
<td>$42.62</td>
<td>$11.72</td>
<td>3.6</td>
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<tr>
<td>$60</td>
<td>$0.76</td>
<td>0.8</td>
<td>169</td>
<td>4.2</td>
<td>$49.35</td>
<td>$11.54</td>
<td>4.3</td>
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<tr>
<td>$70</td>
<td>$0.78</td>
<td>0.6</td>
<td>278</td>
<td>5.1</td>
<td>$55.74</td>
<td>$11.40</td>
<td>4.9</td>
</tr>
</tbody>
</table>

\(^{(1)}\) Assumes WTI/Ed Light differential of $2.50 / $4.00 / $5.50 respectively, AECO $2.00/GJ

\(^{(2)}\) See “Type Curves” under “Information on Reserves and Operational Information”.

\(^{(3)}\) Based on ½ cycle costs, recycle ratio based on first year netbacks.

Consistently Exceeding Type Curves - Quick Payouts Drive Top Quartile Organic Growth
Production
- 1,300 boed (78% liquids)
  - 800 boed Cardium
  - 500 boed Belly River

Upside Potential
- 119 net Hz locations (75% operated)\(^\text{1}\)

Land
- 54,724 (40,108 net) acres, average 73% WI

Facilities
- 5 major oil facilities with custom treating & water disposal
- 2 (100% WI) batteries tied directly into Pembina Pipelines Sales
- Firm service for > 80% of gas volumes

InPlay Wells
InPlay Rights
Cardium Vertical
Cardium Horizontal

Pembina Type Curve Economics\(^\text{2}\) *

<table>
<thead>
<tr>
<th>WTI</th>
<th>Fx (USD/CAD)</th>
<th>Payout (yrs)</th>
<th>IRR (%)</th>
<th>NPV 10 ($mm)</th>
<th>Yr 1 Netback(^\text{3}) (Cdn/boe)</th>
<th>F&amp;D (/boe)</th>
<th>Recycle ratio (times)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$50</td>
<td>$0.74</td>
<td>1.5</td>
<td>61</td>
<td>2.0</td>
<td>$42.12</td>
<td>$12.08</td>
<td>3.5</td>
</tr>
<tr>
<td>$60</td>
<td>$0.76</td>
<td>1.1</td>
<td>94</td>
<td>2.7</td>
<td>$49.20</td>
<td>$11.82</td>
<td>4.2</td>
</tr>
<tr>
<td>$70</td>
<td>$0.78</td>
<td>0.9</td>
<td>138</td>
<td>3.3</td>
<td>$55.92</td>
<td>$11.65</td>
<td>4.8</td>
</tr>
</tbody>
</table>

*(1) See “Drilling Locations” under “Information on Reserves and Operational Information”
*(2) See “Type Curves” under “Information on Reserves and Operational Information”
*(3) Assumes WTI/Ed Light differential of $2.50 / $4.00 / $5.50 respectively, AECO $2.00/GJ

* Based on \(\frac{3}{4}\) cycle costs, recycle ratio based on first year netbacks.
Significant Light Oil Resource (high quality oil - premium price to Edmonton Light)

- Internal estimate of 12 - 20 mmbbl original oil in place per section

Upside Potential

- Potential recovery of 250 mbbl to >500 mbbl per well
- 290 net locations (at 6 wells / section) only targeting uppermost shale
- Estimate pad-development well costs at ~$5.5 mm (1.5 mile)

Reservoir

- Well control indicates thick high quality shales across InPlay lands
- Up to 3 pay zones present – industry focusing on upper zone at this point although operators have started drilling the lower zones
- Reservoir is over-pressured (30-60%)
- Depths between 2000m – 2400m

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“The East Shale Basin Duvernay Continues to Gain Momentum and is Quickly Evolving its Position to Become One of the Premier Oil Resource Plays in North America”

“World-class rock characteristics combined with a massive resource in-place”

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(1) Seaton-Jordan report undeveloped Duvernay land valued at $49.6MM ($1,619 per acre for 30,640 acres) at Dec 31, 2018
(2) See “Drilling Locations” under “Information on Reserves and Operational Information”
(3) See Appendix for a cross section displaying reservoir correlation from Joffre to Huxley
(4) From BMO Capital Markets “East of the Reef – Duvernay Oil Play” analysis, Spring 2019
Improving completion technology is leading to better rates and recoveries

1-11-34-24W4: First Duvernay Hz that was drilled in the Huxley area
- >275mbbl EUR 1.0 mile Hz well even with early stage completion technology used in 2015

2-26-34-24W4: Closest producing Hz to InPlay’s well using recent completion technology
- >600mbbl EUR for ~1.7 mile Hz well
Estimated Duvernay Development Economics\(^{(1,2,3)}\)

- Technology improvements (e.g. frac optimization) will continue to enhance play economics (as experienced in most N. American shale plays)
- >170 wells drilled by industry to date; anticipate an additional 60 wells drilled over next 12 months
- Crown land is >50% more economic than Freehold land (InPlay is 100% Crown)
- Well costs reflect pad development scenario; single delineation wells currently estimated to cost 30%-40% more

<table>
<thead>
<tr>
<th>EUR vs. CAPEX</th>
<th>$4.5mm (1 mile)</th>
<th>$5.5mm (1.5 mile)</th>
<th>$6.5mm (2 mile)</th>
</tr>
</thead>
<tbody>
<tr>
<td>250 mbbl</td>
<td>$4.1mm / 51%</td>
<td>$3.2mm / 32%</td>
<td>$2.2mm / 22%</td>
</tr>
<tr>
<td>315 mbbl</td>
<td>$5.9mm / 86%</td>
<td>$5.3mm / 54%</td>
<td>$4.4mm / 37%</td>
</tr>
<tr>
<td>400 mbbl</td>
<td>$8.5mm / 173%</td>
<td>$8.0mm / 101%</td>
<td>$7.3mm / 67%</td>
</tr>
<tr>
<td>500 mbbl</td>
<td>$11.6mm / 396%</td>
<td>$11.1mm / 205%</td>
<td>$10.6mm / 127%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>EUR vs. CAPEX</th>
<th>$4.5mm (1 mile)</th>
<th>$5.5mm (1.5 mile)</th>
<th>$6.5mm (2 mile)</th>
</tr>
</thead>
<tbody>
<tr>
<td>250 mbbl</td>
<td>$4.9mm / 64%</td>
<td>$4.1mm / 40%</td>
<td>$3.1mm / 27%</td>
</tr>
<tr>
<td>315 mbbl</td>
<td>$6.8mm / 110%</td>
<td>$6.3mm / 68%</td>
<td>$5.5mm / 46%</td>
</tr>
<tr>
<td>400 mbbl</td>
<td>$9.6mm / 232%</td>
<td>$9.1mm / 131%</td>
<td>$8.6mm / 85%</td>
</tr>
<tr>
<td>500 mbbl</td>
<td>$12.9mm / 576%</td>
<td>$12.5mm / 280%</td>
<td>$12.1mm / 167%</td>
</tr>
</tbody>
</table>

<table>
<thead>
<tr>
<th>EUR vs. CAPEX</th>
<th>$4.5mm (1 mile)</th>
<th>$5.5mm (1.5 mile)</th>
<th>$6.5mm (2 mile)</th>
</tr>
</thead>
<tbody>
<tr>
<td>250 mbbl</td>
<td>$5.5mm / 78%</td>
<td>$4.9mm / 49%</td>
<td>$4.0mm / 33%</td>
</tr>
<tr>
<td>315 mbbl</td>
<td>$7.6mm / 136%</td>
<td>$7.1mm / 83%</td>
<td>$6.5mm / 56%</td>
</tr>
<tr>
<td>400 mbbl</td>
<td>$10.5mm / 299%</td>
<td>$10.1mm / 164%</td>
<td>$9.6mm / 105%</td>
</tr>
<tr>
<td>500 mbbl</td>
<td>$14.0mm / 814%</td>
<td>$13.7mm / 369%</td>
<td>$13.3mm / 213%</td>
</tr>
</tbody>
</table>

(1) Assumes long term WTI/Ed Light differential of $4.00 / $5.50 / $7.00 respectively, AECO $2.00/GJ
(2) See “Type Curves” under “Information on Reserves and Operational Information”
(3) Crown land economics
## 2019 Forecast

### Commodity Price Assumptions\(^{(1)}\)

<table>
<thead>
<tr>
<th>Commodity</th>
<th>Assumption</th>
</tr>
</thead>
<tbody>
<tr>
<td>WTI Oil Price (US$/bbl)</td>
<td>$60.50</td>
</tr>
<tr>
<td>Edmonton Par (C$/bbl)</td>
<td>$73.50</td>
</tr>
<tr>
<td>AECO Gas Price ($/mcf)</td>
<td>$1.65</td>
</tr>
</tbody>
</table>

### Operational Forecast

<table>
<thead>
<tr>
<th>Forecast</th>
<th>Assumption</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Production (boed) (% liquids)</td>
<td>4,900 – 5,100 (70%)</td>
</tr>
<tr>
<td>Exit Production (boed) (% liquids)</td>
<td>5,400 – 5,600 (70%)</td>
</tr>
<tr>
<td>Adjusted Funds Flow From Operations ($mm)</td>
<td>$41 - $44</td>
</tr>
<tr>
<td>Capital Program(^{(2)}) ($mm)</td>
<td>$36</td>
</tr>
<tr>
<td>Net Cardium Horizontal Wells</td>
<td>9</td>
</tr>
<tr>
<td>Free Cash Flow ($mm)</td>
<td>$5 - $8</td>
</tr>
<tr>
<td>Q4 Debt / Adjusted Funds Flow</td>
<td>1.0x</td>
</tr>
</tbody>
</table>

### Sensitivities Adjusted funds flow

<table>
<thead>
<tr>
<th>Sensitivity</th>
<th>Impact ($mm)</th>
</tr>
</thead>
<tbody>
<tr>
<td>+/- $5/bbl WTI</td>
<td>$4.1</td>
</tr>
<tr>
<td>+/- $0.25/mcf AECO</td>
<td>$0.6</td>
</tr>
</tbody>
</table>

---

\(^{(1)}\) Assumptions include 2019 averages including FX 0.75 CDN/USD and H2 WTI/Edmonton Light differential of $6.00 USD/bbl

\(^{(2)}\) Includes completion capital for 2 (2.0 net) Cardium wells drilled in Q4 2018
2018 Year End Pro Forma Net Asset Value

<table>
<thead>
<tr>
<th></th>
<th>PDP + PDNP @ 10% (1000’s) (1)</th>
<th>TP @ 10% (1000’s)</th>
<th>TPP @ 10% (1000’s)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reserves Value (Before Tax) (2)</td>
<td>148,644</td>
<td>252,454</td>
<td>387,682</td>
</tr>
<tr>
<td>Undeveloped Land (3)</td>
<td></td>
<td>62,515</td>
<td></td>
</tr>
<tr>
<td>Debt + Working Capital Deficiency (4)</td>
<td>-53,670</td>
<td></td>
<td></td>
</tr>
<tr>
<td>Net Asset Value (5)</td>
<td>157,489</td>
<td>261,298</td>
<td>396,526</td>
</tr>
<tr>
<td>Basic Common Shares</td>
<td></td>
<td></td>
<td>68,257</td>
</tr>
</tbody>
</table>

2018 NAV / Share

<table>
<thead>
<tr>
<th></th>
<th>$2.31</th>
<th>$3.83</th>
<th>$5.81</th>
</tr>
</thead>
</table>

2017 NAV / Share

<table>
<thead>
<tr>
<th></th>
<th>$2.00</th>
<th>$3.29</th>
<th>$5.25</th>
</tr>
</thead>
</table>

Future Development Capital

<table>
<thead>
<tr>
<th></th>
<th>185,700</th>
<th>239,600</th>
</tr>
</thead>
</table>

Years of 2019 CAPEX

|                      | 5.2 | 6.7 |
Summary

- Top tier organic per share light oil production growth
- Technically strong, efficient, Cardium focused light oil producer
- Emphasis on cost reductions is continually increasing margins
- Dedicated to maintaining financial flexibility
- Positioned for value based tuck-ins
- Built for sustainability in a volatile commodity price environment
  - Strong balance sheet, high netback, low decline, economic inventory
- High impact Duvernay provides long term potential for material upside
- High torque to upside with oil pricing
Appendix
InPlay Team
Strong Technically and Value Creators

Doug Bartole, President and CEO and Director, P. Eng., ICD.D (over 25 years)
• Founder, President and CEO of Vero Energy; VP Operations of True Energy; Management and Engineering roles at Husky Energy, Renaissance Energy and PanCanadian Petroleum
• Director of Invicta Energy (founder of Royal Acquisition Corp. which was the public RTO vehicle for Invicta)
• Member of APEGA, Institute of Corporate Directors, and a Governor of CAPP (Canadian Association of Petroleum Producers)

Kevin Yakiwchuk, Vice President Exploration, MSc, P. Geol. (over 24 years)
• Founder and VP Exploration at Vero Energy; VP Exploration at True Energy; Geologist at Crestar Energy, Renaissance Energy and Shell Canada

Gordon Reese, BSc. Geol., Vice President Business Development (over 33 years)
• Founder, President and CEO of Invicta Energy; President and CEO at Cipher Energy, VP Exploration at True Energy and various prospect generation and management roles at CS Resources and Gulf Canada.

Thane Jensen, Vice President Operations, P. Eng. (over 25 years)
• Sr. V.P. Operations, Exploration and Development, and prior VP Engineering at Penn West Exploration
• Reservoir Engineer, Exploitation Engineer, and Drilling and Completions Engineer at PanCanadian Petroleum Ltd.

Darren Dittmer, CFO, CPA, CMA (over 23 years)
• CFO of Barrick Energy Inc. from September 2008 until sale of all assets in July 2013
• Controller and CFO of Cadence Energy and prior Controller of Kereco Energy, Ketch Resources and Upton Resources
InPlay Team

Strong and Experienced Board

Doug Bartole, P. Eng., ICD.D
• President and CEO of InPlay Oil

Dennis Nerland, LLB, ICD.D
• Partner of Nerland Lindsey LLP.
• Member of the Law Society of Alberta, the Canadian Tax Foundation, the Canadian Bar Association, the Society of Trust and Estate Practitioners, and the Institute of Corporate Directors.

Dale Shwed
• President and CEO of Crew Energy Inc. (spin-out of Baytex in 2003)
• Former Founder, President and CEO of Baytex Energy Ltd. (grew production to over 40,000 boed)
• Currently sits on the board of a number of private and public oil and gas companies

Steve Nikiforuk, CA, ICD.D
• Private business man with excellent management and executive experience in a CFO role for public and private companies
• Chair of the Audit Committee for Whitecap Resources; board member of several public and private companies

Don Cowie
• Previously Chairman Investment Advisory Board at JOG Capital Corp. until his retirement at the end of 2017
• Currently sits on the board of a number of private and public oil and gas companies

Craig Golinowski
• President of JOG Capital Corp.
• Currently sits on the board of a number of private and public oil and gas companies within JOG’s portfolio
Initial drilling has focused on the Upper Duvernay pay interval. Mid and Lower Duvernay pay intervals are beginning to be tested by some operators.
INFORMATION ON RESERVES & OPERATIONAL INFORMATION

General - All amounts in this presentation are stated in Canadian dollars unless otherwise specified. Throughout this presentation, the terms Boe (barrels of oil equivalent) and Mmboe (millions of barrels of oil equivalent) are used. Such terms when used in isolation, may be misleading. In accordance with Canadian practice, production volumes and revenues are reported on a company gross basis, before deduction of Crown and other royalties and without including any royalty interest, unless otherwise stated. Unless otherwise specified, all reserves volumes in this presentation (and all information derived therefrom) are based on “company gross reserves” using forecast prices and costs. Complete disclosure of our oil and gas reserves and other oil and gas information in accordance with NI 51-101 is available on our SEDAR profile at www.sedar.com. The recovery and reserve estimates contained herein are estimates only and there is no guarantee that the estimated reserves will be recovered. In relation to the disclosure of estimates for individual properties, such estimates may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation. The Company’s belief that it will establish additional reserves over time with conversion of probable undeveloped reserves into proved reserves is a forward-looking statement and is based on certain assumptions and is subject to certain risks, as discussed previously under the heading “Forward-Looking Information and Statements.”

Reserves - Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates as follows:

- 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.

Oil & Gas Metrics - This presentation may contain metrics commonly used in the oil and natural gas industry, such as “recycle ratio”, “finding and development costs”, “finding and development recycle ratio”, “finding, development and acquisition costs”, “operating netbacks”, “Funds flow netbacks”, “RLI”, “recycle ratio” and “IRR”. These terms do not have standardized meanings or standardized methods of calculation and therefore may not be comparable to similar measures presented by other companies, and therefore should not be used to make such comparisons. Management uses oil and gas metrics for its own performance measurements and to provide shareholders with measures to compare InPlay’s operations over time. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this presentation, should not be unduly relied upon.

Test Results and Initial Production Rates - A pressure transient analysis or well-test interpretation has not been carried out and thus certain of the test results provided herein should be considered to be preliminary until such analysis or interpretation has been completed. Test results and initial production rates disclosed herein may not necessarily be indicative of long term performance or of ultimate recovery.

BOE equivalent - Barrel of oil equivalents or BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 mcf : 1 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. Given that the value ratio based on the current price of crude oil as compared to natural gas is significantly different than the energy equivalency of 6:1, utilizing a 6:1 conversion basis may be misleading as an indication of value.

Type Curves - The type curves presented herein reflect a selection from a type curves library provided by InPlay’s independent reserve evaluator. In each case the type curve presented is that which the company feels best represents the expected average drilling results based upon InPlay producing wells in the area as well as non-InPlay wells determined by the company to be analogous for purposes of the type curve assignments. Internal Forecast curves incorporate the most recent data from actual well results and would only be representative of the specific drilled locations. There is no guarantee that InPlay will achieve the estimated or similar results derived therefrom.

Drilling Locations - This presentation discloses drilling locations in two categories: (i) booked locations; and (ii) unbooked locations. Booked locations are proved locations and probable reserves derived from the applicable independent reserves evaluations and account for drilling locations that have associated proved and/or probable reserves, as applicable. Of the 533 drilling locations identified herein, 101 are proved locations, 252 are probable locations and 420 are unbooked locations. Unbooked locations are internal management estimates based on prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Unbooked locations do not have attributed reserves or resources. Unbooked locations have been identified by management as an estimation of the Company’s potential multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the InPlay will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which InPlay actually drills wells will ultimately depend upon the availability of capital, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been derived by either InPlay or other industry participants drilling existing wells in relative close proximity to such unbooked drilling locations, certain unbooked drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir. Therefore, there is uncertainty whether wells will be drilled in such unbooked locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

Net Present Value Estimates - It should not be assumed that the net present value of the estimated future net revenues of the reserves of InPlay included in this presentation represent the fair market value of the reserves. There is no assurance that the forecast prices and cost assumptions will be attained and variations could be material.
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