Investor Update

June 26, 2018
Why we do what we do...

We believe:

- world demand for clean and reliable source of energy is rapidly growing
- technological advancements makes our energy cost competitive on a world scale
- in developing our world-class resource using the highest standards, environmentally and socially
- The world trusts doing business with Canada

PONY is developing a world-class resource of clean natural gas in Canada

Source: BP Global Energy Outlook, 2017
Increases in Canadian natural gas demand is expected to be significant.

Estimated 50% potential growth in demand for Canadian natural gas in the next 5 years.

Source: RBC Capital Markets; January 2018
Proposed West Coast LNG Projects

### Proposed LNG Projects

<table>
<thead>
<tr>
<th>Project</th>
<th>Capacity</th>
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</thead>
<tbody>
<tr>
<td>Exxon – Imperial WCC LNG</td>
<td>~4.0 Bcf/d</td>
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<tr>
<td>Shell &amp; Partners - LNG Canada</td>
<td>~1.9 – 3.8 Bcf/d</td>
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<td>(FID expected in 2018)</td>
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<tr>
<td>Pembina Pipeline Corp. Jordan Cove LNG</td>
<td>~1.4 Bcf/d</td>
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<tr>
<td>Chevron / Apache KM LNG</td>
<td>~1.3 Bcf/d</td>
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<tr>
<td>Pacific Oil &amp; Gas / Wood fibre LNG</td>
<td>~0.3 – 1.0 Bcf/d</td>
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<td>(FID expected in 2018)</td>
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<td><strong>TOTAL</strong></td>
<td><strong>~8.9 – 11.5 Bcf/d</strong></td>
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Transportation

Firm Transportation & Toll Advantage to West Coast

Enbridge T-North Tolls
- Single toll structure
- $0.18/Mcf
- Pony can deliver at either Station 2 or Sunset Creek for single toll

TransCanada AECO Tolls
- $0.27/Mcf receipt on AECO at Sunset Creek
- $0.20/Mcf delivery off AECO
- $0.81/Mcf delivery into Dawn

PONY has a ~$0.45/Mcf toll advantage to the west coast over natural gas coming from Alberta.
Corporate Profile

**TSX: PONY**

### Our Growth
- **38%** forecasted annual average daily production volume growth (2018 vs. 2017)
- **46%** forecasted annual average daily liquids production growth (2018 vs. 2017)
- **28%** forecasted cash flow per share growth (2018 vs. 2017)

### Production
- **364 MMcfe/d** (60,703 boe/d) Q1 2018, up 69% over Q1 2017
- **5,614 bbls/day** Q1 2018 liquids production, up 78% over Q1 2017
- **28%** Corporate Production Decline at December 31, 2017 per GLJ Petroleum Consultants
- **348 MMcfe/d** (58,000 boe/d) to 360 MMcfe/d (60,000 boe/d) 2018 Production Guidance

### Balance Sheet
- **$142 mm** term debt maturing 2022; **$45 mm** convertible debentures maturing 2021
- **$164 mm** bank debt on borrowing base of **$400 million** as at March 31, 2018
- **$351 mm** total debt as at March 31, 2018

### Trading Metrics
- **1.1 mm** shares trade per day
- **$430 mm** market capitalization
- **161 mm** shares outstanding
Asset

- The Montney is the most economic natural gas liquids play in Canada
- 314 net sections (201,009 net acres) of Montney lands
- 6.9 Tcfe (1,148 MMboe) Proved Plus Probable Reserves with a Proved Plus Probable RLI of 52 years
- 797 Bcfe of Proved Developed Producing reserves

Strategic Advantages

- Firm transportation and processing facilities in-place to meet production growth targets

Sustainable Capital Investment

- Cash flow 2018 capital budget provides production volume and cash flow per share growth without additional leverage

(1) As at December 31, 2017; see Advisories Section
(2) RLI (Reserve Life Index) is calculated using 2017 reserves divided by annualized Q1 2018 production volumes of 364 MMcfe/d (60,703 boe/d)
PONY’s Montney Sweet Spot is:

- 4x thicker than the Marcellus at greater than 300 meters (approximately 1,000 ft.) thick
- a continuous sweet natural gas-saturated zone with no associated or underlying water
- in an area with up to 1.8x over-pressured reservoir
- liquids cut average of approximately 9% during first quarter 2018
  
  * high liquids production at Townsend with potential at Beg and Jedney (drilled and tested first well at Beg in Q1 2018)
  * liquids production over a total of approximately 100,000 acres or 50% of land base
Beg Test Well

Significant Untapped Value in Liquids-Rich Block

- 6.6 day production test
- Final 8 hours of test
  - 2,000 boe/d consisting of:
    - 10 MMcf/d natural gas
    - 360 bbls/d liquids including wellhead and facility recovered liquids; 60% condensate
    - Well was still cleaning up
- Flowing pressure at end of test was 1,625 psi through a 5/8 inch choke
- Will require a 12 kilometer (7.5 mile) pipeline to existing infrastructure

Progress - Beg 27-B
3 Upper Montney wells
9.5 - 11 MMcf/d
10 - 16.5 bbls/MMcf Free Condensate

Progress - Beg 84-J
3 Upper Montney wells
9 - 11 MMcf/d
11 - 32 bbls/MMcf Free Condensate

Black Swan - Beg 80-G
3 Upper Montney wells
6 - 8.5 MMcf/d
5 - 17.5 bbls/MMcf Free Condensate

Black Swan - Beg 20-H
2 Upper Montney wells
5.5 MMcf/d
7 bbls/MMcf Free Condensate

Black Swan - Beg 97-I
Upper Montney well
8 MMcf/d
20 bbls/MMcf Free Condensate

PONY Beg 65-B
Upper Montney well
10 MMcf/d
360 bbls/d liquids / 36 bbls/MMcf (60% Condensate)

Black Swan - Beg 80-G
Upper Montney well
10 MMcf/d
360 bbls/d liquids / 36 bbls/MMcf (60% Condensate)
**The Sweet Spot**

*Top Decile Well Performance*

**PONY has best well in North Montney with 6-month average daily production rate of more than 11 MMcf/d**

Based on cumulative volumes, PONY has **19** of the top **20** wells in the Northern Montney.

**47 of top 100 wells are PONY wells!**

**North Montney 6-Month Cumulative Production Volumes**

- **Painted Pony**
- **Other Producers**

**Top 100 Wells - Northern Montney Field** *(sample set of 1,220 wells)*

*Source: GeoScout; As at Jan 31, 2018*
Production Profile

Impressive Growth

PONY is expecting 38% annual average daily production growth from 2017 to 2018.

Year End 2017
360 MMcfe/d (60,000 boe/d)

Per GLJ Reserve Report
Dec 31, 2017
28% Corporate Decline

Excluding 2018 Capital Program
Volumes, PONY’s production YE 2018
would be approximately
258 MMcfe/d or (43,000 boe/d),
representing a 28% corporate decline.

Year End 2016
139 MMcfe/d (23,204 boe/d)

Year End 2015
94 MMcfe/d (15,604 boe/d)

2018F
348-360 MMcfe/d (58,000-60,000 boe/d)

2017
257 MMcfe/d (42,882 boe/d)
As capital well costs fell, production type curves dramatically improved.

- **Perf & Plug Systems**
  - 21 wells
  - D&C cost $7.7 million

- **1st Generation Open Hole Ball Drop System**
  - 33 wells
  - D&C cost $6.9 million

- **Current Generation Open Hole Ball Drop System**
  - 94 wells
  - D&C cost $4.0 million

Management Type Curve increased 50%.

Continued type curve improvement with average well booking of 9 Bcfe/well.
Single Well Economics by Area

2018 Management Type Curves

Management Type Curves
- Daiber (dry)
- Blair (lean)
- Townsend (liquids-rich)

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<tr>
<th>Single Well Economics</th>
<th>IRR</th>
<th>NPV10</th>
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<tbody>
<tr>
<td>Daiber (dry)</td>
<td>54%</td>
<td>$4.7 mm</td>
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<tr>
<td>Blair (lean; 15 bbls/MMcf)</td>
<td>64%</td>
<td>$6.2 mm</td>
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<tr>
<td>Townsend (liquids-rich; 36 bbls/MMcf)</td>
<td>39%</td>
<td>$2.9 mm</td>
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</table>

Capital Costs
- Drilling: $1.9 million
- Completions: $2.1 million
- Equip / Tie-in: $0.55 million
- TOTAL: $4.55 million

Based on: $65/bbl WTI; $2.00/Mcf AECO; USD/CAD $0.79
Single Well Development Economics

Price Sensitivity (Half Cycle)

- **Townsend** (liquids-rich)
- **Blair** (lean)
- **Daiber** (dry)

Liquids-enhanced, Blair wells provide exposure to stronger Condensate, NGL and natural gas pricing.

High-rate Daiber wells provide natural gas pricing torque.

Pricing Flat at: $65/bbl WTI; USD/CAD $0.79
Canadian Natural Gas Reserves

As at Dec 31, 2017

PONY’s Proved plus Probable natural gas reserves of 6.5 Tcf (excludes liquids) positions PONY with the third-largest natural gas reserves of any publicly traded company in Canada.

73 MMbbls of Proved plus Probable liquids

\[
\text{\$4.37/sh (EV) / 0.45 bbls/sh} = 9.71/2P \text{ bbl}
\]

Assuming Enterprise Value @ \$4.85/sh

($2.20/sh equity + $2.17/sh debt) on 6.9 Tcfe of 2P Reserves

\[
\text{\$4.37/sh / 42.9 Mcfe/sh} = 0.10/\text{Mcfe}
\]

or

\[
\text{\$0.61/boe}
\]

Total Proved

Probable

Natural Gas Reserves (Tcf)

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Reserve Information
As at Dec 31, 2017

6.9 Tcfe of Proved Plus Probable reserves with an NPV10 of $3.3 billion* ($20.53/share)

2017 Reserves Highlights

• 64% increase in Proved Developed Producing reserves
• 26% of Total Proved reserves are Proved Developed Producing
• 41% increase in Proved Plus Probable reserves
• 45% of Proved Plus Probable reserves are Total Proved
• Proved Plus Probable reserves include 73 MMbbls of liquids
• Reserve Life Index of:
  • 7 years - Proved Developed Producing
  • 27 years - Total Proved
  • 52 years - Proved Plus Probable

*Note: NPV calculated using 10% discount rate; GLJ Pricing as of January 2018; 2018 AECO $2.20/MMbtu; 2019 AECO $2.54/MMbtu
2017 FD&A Recycle Ratios (incl FDC changes)

3-Year Average FD&A Recycle Ratios (incl FDC changes)

2017 F&D Recycle Ratio

1.0x
1.1x
1.3x
1.6x
1.8x
1.9x
3.2x

Note:
FD&A – Finding, Development & Acquisition costs
F&D – Finding and Development costs
2018 Sustainable Capital Spending

Cash Flow Budget

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Annual Average Daily Production (forecast)
- Annual Average Daily Production (actual)
- Capital Development Program
- Cash Flow (actuals)
- 2018 Cash Flow (forecast)

Net of Interest Expense, G&A, and Capital Lease Expense
(2018 pricing based on WTI US$65/bbl, NYMEX US$3.00, AECO CAD$2.00/Mcf, F/X CAD$0.79)

2018 capital development program to be $145 - $165 million, matching 2018 cash flow

At $2.00 AECO, PONY grows year-over-year cash flow per share by 28% in 2018

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2015: 5.7x
2016: 2.0x
2017: 2.6x
2018e: 2.7x
Physical and financial fixed price hedges provide significant protection from natural gas price volatility, stabilizing annual cash flow.
Solid Margins Drive Earnings

Cost Efficiencies Drive Higher Cash Flow per Mcfe

PONY can deliver earnings despite low AECO prices due to very low DD&A driven by strong capital efficiencies.

Diverse fixed-price contracts and financial hedges deliver strong netbacks despite low AECO pricing.

*Non-cash items include stock based compensation, accretion expense, and DD&A (does not include unrealized gain/loss on risk management contracts)
Return on Average Capital Employed (ROACE)

Illustrates Operational Sustainability

Source: Scotiabank Global Banking and Markets – “The Valuation Book” February 2018;
ROACE = earnings before interest & taxes (EBIT) / (average total assets – average current liabilities)
Market Diversification

Natural Gas Sales Points

**AECO Markets**
- 152 → 161 MMcf/d end of 2018 (fixed price & spot)

**SUMAS Market**
- 28 → 32 MMcf/d End of 2018 (spot)

**DAWN Market**
- 36 MMcf/d (Current)
- 44 MMcf/d (Nov 2018)
- 76 MMcf/d (Nov 2019) (fixed price & spot)

**NYMEX Market**
- 40 → 26 MMcf/d end of 2018 (basis contracts)

**Current US Exports** 3.8 Bcf/d
- 2019 Additions 2.7 Bcf/d
- 2020 Additions 3.0 Bcf/d
- Total (end 2020) 9.5 Bcf/d

**MEDICINE HAT**
- 14-year contract to initially deliver 10 MMcf/d to Methanex’s methanol plant in Medicine Hat, Alberta increasing to 50 MMcf/d by 2023

**PONY Sales / Pricing Exposure**
65% of PONY’s Q2 – Q4 2018 production volumes are protected through a combination of physical and financial contracts at a volume-weighted average price of $3.88/Mcfe.

Volumes not under contract are presumed to be sold at index pricing as at May 1, 2018.
Hedging Profile

Prudent Risk Management

Percentage on Fixed Price Contract
(Financial and Physical)

Q1 2019 | Q2 2019 | Q3 2019 | Q4 2019 | Average
--- | --- | --- | --- | ---
Natural Gas Hedges | N/A | N/A | N/A | N/A
Condensate Hedges | N/A | N/A | N/A | N/A
Propane Hedges | N/A | N/A | N/A | N/A

Fixed Price Contract Volumes
(Financial / Physical Fixed Price)

Liquids FP
- $74.25/bbl
- 23%

DAWN FP
- $3.77/Mcf
- 12%

AECO FP
- $3.27/Mcf
- 30%

Station 2 FP
- $2.74/Mcf
- 35%

Natural Gas Volume Hedged (Mcf/d)

Q1 2019: $3.06/Mcf
Q2 2019: $3.02/Mcf
Q3 2019: $3.00/Mcf
Q4 2019: $2.97/Mcf
Average Remaining 2018: $2.97/Mcf

Condensate Hedges

Q1 2019: $2.10/Mcf
Q2 2019: $2.10/Mcf
Q3 2019: $2.10/Mcf
Q4 2019: $2.10/Mcf
Average Remaining 2018: $2.10/Mcf

Propane Hedges

Q1 2019: $2.10/Mcf
Q2 2019: $2.10/Mcf
Q3 2019: $2.10/Mcf
Q4 2019: $2.10/Mcf
Average Remaining 2018: $2.10/Mcf

Liquids Volume Hedged (bbls/d)

Q1 2019: 8,000 bbls/d
Q2 2019: 6,000 bbls/d
Q3 2019: 4,000 bbls/d
Q4 2019: 2,000 bbls/d
Average 2019: 4,000 bbls/d

Fixed Price Contracts

- Q1 2019: $3.02/Mcf
- Q2 2019: $2.97/Mcf
- Q3 2019: $2.93/Mcf
- Q4 2019: $3.13/Mcf
- Average Remaining 2018: $3.02/Mcf

Liquids Hedges

- Q1 2019: $3.06/Mcf
- Q2 2019: $2.74/Mcf
- Q3 2019: $2.97/Mcf
- Q4 2019: $3.01/Mcf
- Average 2019: $3.01/Mcf

PAINTED PONY ENERGY
Massive reserves base
Top well performance with increasing liquids cut
Low well costs
Firm transportation to diverse pricing hubs
Attractive relative valuation
Well situated to supply Canadian west coast LNG projects
Appendices & Advisories
Diversified Market Exposure
2018 / 2019 Sales Contracts Support Strong Netbacks

Reflective of PONY’s heat content, natural gas volumes converted from GJ to Mcf at a conversion ratio of 1 : 1.15

<table>
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<tr>
<th>MOG conversion 1:1.5</th>
<th>2018 Q2</th>
<th>2018 Q3</th>
<th>2018 Q4</th>
<th>2019 Q1</th>
<th>2019 Q2</th>
<th>2019 Q3</th>
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<td>31,611</td>
<td>31,611</td>
<td>31,611</td>
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<td>ST 2</td>
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<tr>
<td>Fixed Price ST 2</td>
<td>66,557</td>
<td>62,699</td>
<td>59,710</td>
<td>40,870</td>
<td>32,174</td>
<td>21,739</td>
<td>6,666</td>
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<tr>
<td>TOTAL MARKETS</td>
<td>313,643</td>
<td>309,325</td>
<td>309,325</td>
<td>309,325</td>
<td>309,325</td>
<td>309,325</td>
<td>309,325</td>
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<tr>
<td>AVERAGE PRICE C$/Mcf</td>
<td>$2.36</td>
<td>$2.50</td>
<td>$2.61</td>
<td>$2.74</td>
<td>$2.01</td>
<td>$1.89</td>
<td>$2.29</td>
<td></td>
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<tr>
<td>US NYMEX US$/Mmbtu</td>
<td>$(1.47)</td>
<td>$(1.52)</td>
<td>$(1.52)</td>
<td>$(1.52)</td>
<td>$(1.52)</td>
<td>$(1.56)</td>
<td>$(1.47)</td>
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</tbody>
</table>

Painted Pony actively markets the majority of natural gas volumes into a diversity of sales points and accessing a diversity of pricing.
Financial Strength

Term Debt and Credit Facility Provide Flexibility

$400 Million Syndicated Credit Facility
- Secured, Reserve Based Lending
- Matures May 2020
- $164 million drawn as at March 31, 2018
- $40 million in Letters of Credit

$142 Million Senior Unsecured Notes
- Held by Magnetar Capital
- 8.5% Coupon
- Mature in 2022
- Not callable for 3 years

$45 Million Subordinated Convertible Debentures
- Held by Magnetar Capital
- 6.5% Coupon
- $5.60 Conversion Price
- Mature in 2021 (subject to any conversion)
- ‘No Shorting’ Provision included
<table>
<thead>
<tr>
<th>Institution</th>
<th>Analyst</th>
</tr>
</thead>
<tbody>
<tr>
<td>AltaCorp Capital</td>
<td>Patrick O’Rourke</td>
</tr>
<tr>
<td>BMO Capital Markets</td>
<td>Michael Murphy / Ray Kwan</td>
</tr>
<tr>
<td>Canaccord Genuity Corp.</td>
<td>Anthony Petrucci</td>
</tr>
<tr>
<td>CIBC World Markets</td>
<td>David Popowich</td>
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<tr>
<td>Cormark Securities Inc.</td>
<td>Garett Ursu</td>
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<tr>
<td>Eight Capital</td>
<td>Adam Gill</td>
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<tr>
<td>GMP FirstEnergy</td>
<td>Cody Kwong</td>
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<tr>
<td>IA Securities</td>
<td>Michael Charlton</td>
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<tr>
<td>National Bank Financial</td>
<td>Dan Payne</td>
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<tr>
<td>Paradigm Capital Inc.</td>
<td>Ken Lin</td>
</tr>
<tr>
<td>Raymond James</td>
<td>Jeremy McCrea</td>
</tr>
<tr>
<td>RBC Capital Markets</td>
<td>Michael Harvey</td>
</tr>
<tr>
<td>Scotiabank Global Banking &amp; Markets</td>
<td>Cameron Bean</td>
</tr>
<tr>
<td>TD Securities</td>
<td>Juan Jarrah</td>
</tr>
<tr>
<td>Tudor Picker Holt &amp; Co</td>
<td>Aaron Swanson</td>
</tr>
</tbody>
</table>
Corporate Overview

Auditor KPMG LLP
Evaluation Engineers GLJ Petroleum Consultants Ltd.
Banks The Toronto-Dominion Bank
The Bank of Nova Scotia
Alberta Treasury Branches
Canadian Imperial Bank of Commerce
Royal Bank of Canada
HSBC Bank Canada
Wells Fargo Bank

Transfer Agent TSX Trust Company

Corporate Office
1800, 736 – 6th Avenue SW, Calgary, AB T2P 3T7
Toll Free Investor 1 (866) 975-0440
Tel (403) 475-0440 Fax (403) 238-1487
Email: info@paintedpony.ca
www.paintedpony.ca
This presentation contains a summary of management’s assessment of results and should be read in conjunction with the Consolidated Financial Statements and related Management’s Discussion and Analysis for the quarter ended March 31, 2018, as filed on SEDAR. This presentation contains certain forward-looking statements, which include assumptions with respect to (i) drilling success; (ii) commodity prices; (iii) production; (iv) reserves; (v) future capital expenditures; (vi) future operating costs; (vii) availability of gas processing facilities; (viii) cash flow; (ix) potential markets for the Corporation’s production; and (x) the availability of LNG export facilities. The reader is cautioned that assumptions used in the preparation of such information may prove to be incorrect.

Certain information regarding the Corporation set forth in this presentation, including statements regarding expectations and forecasts for the Corporation’s future plans and operations, the planning and development of certain prospects, production estimates, reserve estimates, productive capacity and economics of new wells, undeveloped land holdings and values, capital expenditures and the timing and allocation thereof (including the number, location and costs of planned wells), facility expansion plans, the total future capital required to bring undeveloped proved and probable reserves onto production, and expected production growth, may constitute forward-looking statements under applicable laws and necessarily involve substantial known and unknown risks and uncertainties. These forward-looking statements are subject to numerous risks and uncertainties, certain of which are beyond the Corporation’s control, including without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, failure of foreign markets to become accessible, the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, environmental risks, competition, the lack of availability of qualified personnel or management, inability to obtain drilling rigs or other services, capital expenditure costs, including drilling, completion and facility costs, unexpected decline rates in wells, wells not performing as expected, stock market volatility, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources, the impact of general economic conditions in Canada, the United States and overseas, industry conditions, changes in laws and regulations (including the adoption of new environmental laws and regulations) and changes in how they are interpreted and enforced, increased competition, fluctuations in foreign exchange or interest rates and market valuations of companies with respect to announced transactions and the final valuations thereof. Readers are cautioned that the foregoing list of factors is not exhaustive. The Corporation’s actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits the Corporation will derive therefrom. All subsequent forward-looking statements, whether written or oral, attributable to the Corporation or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. Additional information on these and other factors that could affect the Corporation’s operations and financial results are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) or the Corporation’s website (www.paintedpony.ca), including the Corporation’s MD&A for the quarter March 31, 2018.

The forward-looking statements contained in this presentation are made as of the date on the front page and the Corporation assumes no obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws. Certain information contained herein is based on, or derived from, information provided by independent third-party sources. The Corporation believes that such information is accurate and that the sources from which it has been obtained are reliable. The Corporation cannot guarantee the accuracy of such information, however, and has not independently verified the assumptions on which such information is based. The Corporation does not assume any responsibility for the accuracy or completeness of such information.

This presentation also contains future-oriented financial information and financial outlook information (collectively, “FOFI”) about prospective results of operations, future net revenue, share capital, cash flow, capital expenditures, net debt and components thereof, all of which are subject to the same assumptions, risk factors, limitations, and qualifications as set forth in the above paragraphs. FOFI contained in this presentation was made as of the date of this presentation and was provided for the purpose of providing information about management’s current expectations and plans relating to the future, including with respect to the Corporation’s ability to fund its expenditures. The Corporation disclaims any intention or obligation to update or revise any forward looking statements or FOFI contained in this presentation, whether as a result of new information, future events or otherwise, unless required pursuant to applicable securities law. Readers are cautioned that the forward looking statements and FOFI contained in this presentation should not be used for purposes of other than for which it is disclosed herein. The forward looking statements and FOFI contained in this presentation are expressly qualified by this cautionary statement.

NON-GAAP MEASURES This presentation contains references to measures used in the oil and gas industry such as “cash flow” and “net debt.” These measures do not have any standardized meanings within International Financial Reporting Standards (“IFRS”) and, therefore, reported amounts may not be comparable to similarly titled measures reported by other companies. These measures have been described and presented in this presentation in order to provide shareholders and potential investors with additional information about the Corporation’s liquidity and its ability to generate funds to finance its operations. Cash flow should not be considered an alternative to, or more meaningful than cash flows from operating activities as determined in accordance with IFRS as an indicator of the Corporation’s performance. Cash flow denotes cash flow from operating activities before the effects of changes in non-cash working capital, share unit expense and decommissioning expenditures. Cash flow is used by the Corporation to evaluate operating results and the Corporation’s ability to fund capital expenditures and repay debt. The Corporation uses net debt as a measure to assess its financial position. Net debt is a non-GAAP measure calculated as bank debt, senior notes, liability portion of convertible debentures, and working capital deficiency, adjusted for the net current portion of fair value of risk management contracts and current portion of finance lease obligation. Included in this presentation are estimates of the Corporation's 2018 cash flow which are based on various assumptions as to production levels, commodity prices and other assumptions. Non-GAAP measures may not be comparable to similar measures reported by other companies. The Corporation does not assume any responsibility for the accuracy or completeness of such information.
NOTE REGARDING RESERVES DISCLOSURE

The securities regulatory authorities in Canada have adopted National Instrument 51-101 – Standards of Disclosure for Oil and Gas Activities ("NI 51-101"), which imposes oil and gas disclosure standards for Canadian public issuers engaged in oil and gas activities. NI 51-101 permits oil and gas issuers, in their filings with Canadian securities regulatory authorities, to disclose proved, probable and possible reserves, and to disclose reserves and production on a gross basis before deducting royalties. Probable and possible reserves are progressively less certain estimates than proved reserves.

All reserves information in this presentation is presented on a gross basis. Gross reserves are the total working interest reserves before the deduction of any royalties and including any royalty interests receivable. Reserves estimates set forth herein with respect to the Corporation are based on the independent engineering evaluation of the Corporation’s oil, natural gas liquids and natural gas reserves (the “GLJ Report”) prepared by GLJ Petroleum Consultants Ltd. (“GLJ”) effective December 31, 2017 and dated March 6, 2018, and reserves estimates set forth herein with respect to the Target are based on an independent engineering evaluation of the Target’s oil, natural gas liquids and natural gas reserves (the “McDaniel Report”) prepared by McDaniel & Associates Consultants Ltd. (“McDaniel”) effective December 31, 2017 and dated March 6, 2018. Before tax net present values set forth herein are based on a 10 percent discount rate and GLJ’s January 1, 2018 forecast prices as applicable.

All estimates of future revenue in this presentation and in the documents incorporated herein by reference, unless otherwise noted, after the deduction of royalties, development costs, production costs and well abandonment costs but before deduction of future income tax expenses and before consideration of indirect costs such as administrative, overhead and other miscellaneous expenses. The estimated future net revenues contained in this presentation and in the documents incorporated herein by reference do not represent the fair market value of the applicable reserves.

In this presentation:

a) the discounted and undiscounted net present value of future net revenues attributable to reserves do not represent the fair market value of reserves;

b) there is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. The recovery and reserve estimates of natural gas and liquids reserves provided in this presentation are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual natural gas and liquids reserves may be greater than or less than the estimates provided in this presentation;

c) the estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation;

d) boe amounts may be misleading, particularly if used in isolation. Boe amounts have been calculated using the conversion ratio of six thousand cubic feet (6 Mcf) to one barrel of oil (1 bbl). A conversion ratio of 6 Mcf to 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 from the energy equivalency of 6:1, utilizing a conversion on a 6:1 basis may be misleading as an indication of value; and

e) Mcfe amounts may be misleading, particularly if used in isolation. Mcfe amounts have been calculated using the conversion ratio of 1 bbl to 6 Mcf. A conversion ratio of 1 bbl to 6 Mcfs 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 from the energy equivalency of 1:6, utilizing a conversion on a 1:6 basis may be misleading as an indication of value.

Reserves are the estimated remaining quantities of conventional natural gas, shale gas and natural gas liquids anticipated to be recoverable from known accumulations, from a given date forward, based on: (i) analysis of drilling, geological, geophysical and engineering data; (ii) the use of established technology; and (iii) specified economic conditions which are generally accepted as reasonable.

Reserves are classified according to the degree of certainty associated with the estimates.

a) 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.

b) 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.

Other criteria that must also be met for the categorization of reserves are provided in the Canadian Oil and Gas Evaluation (“COGE”) Handbook.

Each of the reserves categories (proved and probable) may be divided into developed and undeveloped categories.

(a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

(i) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(ii) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.
(b) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator’s assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

The qualitative certainty levels referred to in the definitions above are applicable to individual reserves entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserve estimates are prepared). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and

(b) at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A quantitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

For additional information regarding the presentation of the Corporation’s reserves and other oil and gas information, see the Corporation’s Form 51-101F1, which may be accessed through the SEDAR website (www.sedar.com) or the Corporation’s website (www.paintedpony.ca).