Montney Liquids-Rich Growth Story

Corporate Presentation
Private and Confidential
March 2020
Track Record of Success Sets Stage for Material Long-Term Value Creation

**Growth Potential**

- Privately-held pure play NE BC Montney producer
  - 100% working interest in a large contiguous land position, associated gathering system, and facility
- 1,400+ drilling locations on de-risked land base
  - 77 wells drilled with 76 onstream
- Adequate liquidity to execute near-term development program
- Remain flexible to evolving market conditions
  - Significant opportunities for future growth in Canadian natural gas demand

**Attractive Economics**

- Economics at low gas prices supported by strong liquids volumes
  - High value condensate consistently exceeds 70% of liquids volumes
- Shallow drilling depths reduce capital costs and improve economics
- Competitive cost structure
- Low royalty structure with attractive royalty credits

**Proven Track Record**

- Capital efficient execution led by experienced management team
- Q4 2019 production of 17,738 Boe/d
  - 2019 exit production of 20,516 Boe/d
- Grew production over 3x since the start of 2016
- 69% 5 year 2P reserves CAGR
- Industry leading inception-to-date 2P FD&A costs of $6.12 per Boe
- Manage production growth to align with risk management program
- Capital budget driven by expected cash flows

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1. See advisories and definitions on pages 33 and 34 hereof.
3. Q4 2019 production consisted of 81 MMcf/d of natural gas, 3,106 Bbl/d of oil and condensate, and 1,149 Bbl/d of natural gas liquids (propane and butane). 2019 exit production consisted of 91 MMcf/d of natural gas, 4,017 Bbl/d of oil and condensate, and 1,279 Bbl/d of natural gas liquids (propane and butane).
4. Growth calculated on production since Q1 2016.
5. 2P = Total Proved Plus Probable Reserves; 2P Reserves CAGR calculated on volumes from December 31, 2014 to December 31, 2019.
Full Development Plan Provides Material and Sustainable Organic Growth\(^{(1)(2)(3)}\)

- Strategically advancing a low-risk development play
  - 2013: initiated pilot program
  - 2015: commercial development began
  - 2018: average annual production of 16,485 Boe/d\(^{(3)}\)
  - 2019: updated full development plan to 8 Bcf type curve
  - Peak production held flat at ~215,000 Boe/d for 10 years

- Top priority remains value creation for shareholders
  - Focus on capital efficiency and profitability

1. See advisories and definitions on pages 33 and 34 hereof.
2. Full development plan ("FDP") is based on a 1,400 well development program which develops ~98% of Saguaro’s existing land base. Assumes 2,500 m Hz wells and an 8 Bcf type curve. FDP is based on 2020 YTD results and will continue to be updated throughout the delineation phase. Any changes to the assumptions used in the FDP will impact the metrics and results including amount of equity raised.
3. 2018 average annual production consisted of 76 MMcf/d of natural gas, 2,752 Bbl/d of oil and condensate, and 1,008 Bbl/d of natural gas liquids (propane and butane). 2019 average annual production consisted of 78 MMcf/d of natural gas, 2,629 Bbl/d of oil and condensate, and 1,133 Bbl/d of natural gas liquids (propane and butane).
4. FDP capital includes all development capital (inclusive from 2013; undiscounted), excluding land. Economic metrics for FDP based on -$0.20/GJ Station 2 differential and 0.75 US$/C$ FX; $1.75/GJ AECO and US$55/Bbl WTI in 2020; $2.00/GJ AECO and US$55/Bbl WTI in 2021; then escalated at 1.5% thereafter. Natural Gas Liquids pricing relative to WTI based on average of IQRE pricing. Economic metrics are based on go forward assumptions. IRR does not include land costs and undeveloped land value.
High Quality Asset in One of North America’s Leading Oil & Gas Plays

- The Montney is a large, world class oil and gas play with leading supply costs and economics
- Saguaro has acquired a large strategic land position in the NE BC Montney
  - 100% working interest in 165 contiguous sections (114,094 acres)
  - Liquids-rich stacked potential
  - Over-pressured with good permeability
  - Shallow depth (1,400-1,900 m) reduces cost and improves economics
- Scale and quality of land base supports impressive growth and capital efficiencies with a drilling inventory of 1,400+ locations
- Access to multiple markets through existing and future egress options
  - Existing and expanding access to AECO, Dawn, Station 2, Chicago, and Sumas hubs
  - TC Energy North Montney Mainline project (in-service first half 2020)
  - Enbridge T-South expansion (in-service ~2021)

1. See advisories on pages 33 and 34 hereof.
### Sproule’s Assessment of Saguaro’s Reserves and Risked Resource Base

1P: 174 MMBoe (22% liquids)
1P HZ Well Count: 214

2P: 466 MMBoe (22% liquids)
2P HZ Well Count: 403

3P: 755 MMBoe (22% liquids)
3P HZ Well Count: 502

- **1P Reserves**: 174 MMBoe
- **2P Reserves**: 466 MMBoe
- **3P Reserves**: 755 MMBoe

#### Additional Information:

1. See advisories and definitions on pages 33 and 34 hereof.
2. Produced volumes as at December 31, 2019. Based on Sproule Reserves Evaluations dated effective December 31, 2019 and Evaluation of the Contingent and Prospective P&NG Resources prepared by Sproule Associates Limited dated October 31, 2017 pursuant to National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities (“NI 51-101”) and the Canadian Oil and Gas Evaluation Handbooks (“COGE Handbook”). Reserves Evaluation based on Sproule Pricing as of December 31, 2019 and Evaluation of the Contingent and Prospective P&NG Resources based on Sproule Pricing as of September 30, 2017. Certain inputs and parameters used in the Sproule reserves and resource evaluations differ due to the effective dates of the respective reports. These differences could be material to the net present values, but would not be expected to be material to the volume estimates. For reference: 1P = Total Proved Reserves; 2P = Total Proved Plus Probable Reserves; 3P = Total Proved Plus Probable Plus Possible Reserves. Possible reserves are those additional reserves that are less certain to be recovered than probable reserves. There is a 10% probability that the quantities actually recovered will equal or exceed the sum of proved plus probable plus possible reserves.
3. All figures include Montney production, reserves, and resources only; excludes Coplin / Charlie Lake / other conventional production, reserves, and resources.
4. Contingent resources are classified as development pending, subject to evaluation drilling, corporate commitment and development timing contingencies, and the chance of development and therefore chance of commerciality has been estimated to be 90%.
5. Prospective resources are undiscovered volumes with an estimated chance of discovery of 95% and a chance of development of 90%, resulting in an aggregated 85% chance of commerciality.

#### Best Estimate Contingent Resource of 345 MMBoe (23% liquids)
- Additional 319 locations (Best Estimate Risked)

#### Best Estimate Prospective Resource of 372 MMBoe (24% liquids)
- Additional 387 locations (Best Estimate Risked)
Stacked Zone Exploitation Multiplies Productive Potential\(^{(1)(2)}\)

- All three Montney targets proven productive
  - Over pressured: 11-15 kPa/m
  - Shallow depth: 1,400-1,900 m
  - Gross pay: up to 265 m across 3 stacked porous zones

- Development plan focuses on Upper and Middle targets

- 77 wells drilled to date\(^{(3)}\):
  - 26 Upper Target
  - 47 Middle Target
  - 4 Lower Target

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1. See advisories on pages 33 and 34 hereof.
2. Porosity from Nutech Petrophysical analysis. 3% porosity cut off.
Successful De-Risking & Delineation Drives Reserve Growth

De-Risking & Delineation
- High confidence in our resource which is 98% de-risked through drilling and competitor activity

Reserve Bookings
- High quality asset has allowed impressive, consistent reserve growth to date and provides large future growth potential
  - 2P Reserves represent ~28% of Saguaro’s estimated well inventory

1. See advisories on pages 33 and 34 hereof.
2. Wells drilled as at March 31, 2020.
3. Illustration based on Sproule’s reserves evaluation dated December 31, 2019.
Substantial, Low Cost Reserves Growth

Sproule December 31, 2019 Reserves Summary

<table>
<thead>
<tr>
<th>Gross Reserves</th>
<th>Proved Developed Producing (PDP)</th>
<th>Total Proved (1P)</th>
<th>Total Proved Plus Probable (2P)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Total Reserves (MBoe)</td>
<td>39,999</td>
<td>174,202</td>
<td>465,905</td>
</tr>
<tr>
<td>NPV10 (BT $MM)</td>
<td>$297</td>
<td>$729</td>
<td>$1,704</td>
</tr>
<tr>
<td>NPV10 (BT $/Boe)</td>
<td>$7.43</td>
<td>$4.19</td>
<td>$3.66</td>
</tr>
<tr>
<td>F&amp;D (Incl. FDC) ($/Boe)</td>
<td>$7.22</td>
<td>$6.77</td>
<td>$6.87</td>
</tr>
<tr>
<td>FD&amp;A (Incl. FDC) ($/Boe)</td>
<td>$7.23</td>
<td>$6.77</td>
<td>$6.87</td>
</tr>
<tr>
<td>Locations (#)</td>
<td>68</td>
<td>214</td>
<td>403</td>
</tr>
</tbody>
</table>

- December 31, 2019 PDP, 1P and 2P reserves have increased since December 31, 2018
  - PDP increased 20% to 40 MMBoe from 33 MMBoe
  - 1P increased 14% to 174 MMBoe from 152 MMBoe
  - 2P increased 11% to 466 MMBoe from 420 MMBoe

1. See advisories and definitions on pages 33 and 34 hereof.
2. PDP reserves are comprised of 78% Gas, 21% NGLs, 0.2% Oil. 1P and 2P reserves are comprised of 78% Gas, 22% NGLs. 1P includes 794.4 MBoe of Proved Developed Non-Producing (PDNP) reserves.
3. Based on Sproule Reserves Evaluations dated effective December 31, 2019 and December 31, 2018, respectively and based on Sproule Pricing as of December 31, 2019 and December 31, 2018, respectively.
5. 2019 Development Capital of $88.6 MM. FD&A and F&D includes Full Development Capital.

1P and 2P Reserves Growth

Attractive FD&A Costs

1. See advisories and definitions on pages 33 and 34 hereof.
2. PDP reserves are comprised of 78% Gas, 21% NGLs, 0.2% Oil. 1P and 2P reserves are comprised of 78% Gas, 22% NGLs. 1P includes 794.4 MBoe of Proved Developed Non-Producing (PDNP) reserves.
3. Based on Sproule Reserves Evaluations dated effective December 31, 2019 and December 31, 2018, respectively and based on Sproule Pricing as of December 31, 2019 and December 31, 2018, respectively.
5. 2019 Development Capital of $88.6 MM. FD&A and F&D includes Full Development Capital.
Attractive Economics
Advancing Well Design to Drive Material Type Curve Improvement\(^{(1)}\)

Three Generations of Saguaro Drills\(^{(2)}\)

<table>
<thead>
<tr>
<th>Generation</th>
<th>HZ Length</th>
<th>Second</th>
<th>Third OH</th>
<th>Upside</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>meters</td>
<td>2,000</td>
<td>2,500</td>
<td>2,500</td>
</tr>
<tr>
<td>IP30</td>
<td>Raw MMcf/d</td>
<td>6.3</td>
<td>7.5</td>
<td>7.9</td>
</tr>
<tr>
<td></td>
<td>Sales MBoe/d</td>
<td>1.3</td>
<td>1.5</td>
<td>1.6</td>
</tr>
<tr>
<td>EUR</td>
<td>Raw Bcf</td>
<td>7.2</td>
<td>8.3</td>
<td>10.0</td>
</tr>
<tr>
<td></td>
<td>Sales MMBoe (Bcfe)</td>
<td>1.4 (8.4)</td>
<td>1.6 (9.6)</td>
<td>1.9 (11.4)</td>
</tr>
</tbody>
</table>

Advancing Well Design Improves Results\(^{(3)}\)

1. See advisories and definitions on pages 33 and 34 hereof.
2. Wells drilled as at March 31, 2020.
3. Data set includes all Upper and Middle targets to February 29, 2020. “OH” refers to Open Hole Ball Drop System. Third Generation – OH (2,500 m HZ; 19 wells) includes 56-E Pad (2,500 m HZ; 5 wells) data.

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Saguaro Resources | Private and Confidential | March 2020
Drilling: Efficiencies Offset Cost of Longer Laterals

- Continuous improvement in drilling practices have reduced days from spud to rig release
  - Repeated 2,500 m pacesetter drilling time of 11 days set in Q2 2019
- Reducing drilling days allows more efficient rig utilization
  - Increases wells per year per rig which simplifies operations
  - Reducing days decreases drilling cost per well
  - New drilling rig in April 2019; wells drilled on pace with 2017 costs

1. See advisories on pages 33 and 34 hereof.
2. Drilling costs shown do not include Deep Well Drilling Credit of ~$1.25 MM per 2,500 m HZ well.
Completions: Evolving Design to Enhance Recoveries and Reduce Costs(1)

- Multiple completion designs tested over time
  - Open Hole vs. NCS systems; 10 to 85 frac stages; 1.0 to 2.0 tonnes/m
  - Current program focus on 40 stage, high tonnage, Open Hole Ball Drop

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1. See advisories on pages 33 and 34 hereof.
Field Infrastructure Designed to Support Long-Term Growth

- Installed four stages of 12" backbone gathering system on Saguaro lands
  - Built to support future growth
  - Construction of fourth stage 12" backbone gathering pipeline completed in October 2019 from 56-E pad to Saguaro facility
- Building water pipelines in conjunction with gathering lines to assist in recycling water as part of our integrated water strategy
  - Cost effective water management between pads and water hub
- Currently receiving Infrastructure Royalty Credits on three stages of gathering system
  - Ultimately reduces the capital burden and increases the economics on pipeline projects
  - 56-E backbone gathering pipeline and associated water pipeline approved for infrastructure royalty credits totalling $5.5 MM

1. See advisories on pages 33 and 34 hereof. Wells drilled as at March 31, 2020.
100% Owned and Operated Facility

- Current capacity of 125 MMcf/d to support production growth
  - Highly competitive cost-to-date of $0.75 MM/MMcfd
- Full site expandable to 1 Bcf/d

<table>
<thead>
<tr>
<th>Process</th>
<th>Capacity</th>
</tr>
</thead>
<tbody>
<tr>
<td>Inlet (Upgraded)</td>
<td>140 MMcf/d</td>
</tr>
<tr>
<td>Compression</td>
<td>140 MMcf/d</td>
</tr>
<tr>
<td>Dehydration</td>
<td>140 MMcf/d</td>
</tr>
<tr>
<td>Amine Sweetening</td>
<td>40 MMcf/d</td>
</tr>
<tr>
<td>Condensate Stabilization</td>
<td>3,000 Bbl/d</td>
</tr>
<tr>
<td>Condensate Storage</td>
<td>7,000 Bbl</td>
</tr>
</tbody>
</table>

1. See advisories on pages 33 and 34 hereof.
2. Current capacity limited to 125 MMcf/d due to condensate stabilization and other required plant upgrades.
### Competitive Single Well Economics at Flat Prices\(^{(1)}\)

<table>
<thead>
<tr>
<th>Generation</th>
<th>Horizontal Well Length (m)</th>
<th>7 Bcf</th>
<th>8 Bcf</th>
<th>10 Bcf</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>Second 2,000 m</td>
<td></td>
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<tr>
<td></td>
<td>Third OH 2,500 m</td>
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<tr>
<td></td>
<td>Upside 2,500 m</td>
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</table>

<table>
<thead>
<tr>
<th>D&amp;C Cost ($MM)</th>
<th>7 Bcf</th>
<th>8 Bcf</th>
<th>10 Bcf</th>
</tr>
</thead>
<tbody>
<tr>
<td>$4.9</td>
<td>$4.9</td>
<td>$4.9</td>
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</tbody>
</table>

<table>
<thead>
<tr>
<th>IRR (BT %)</th>
<th>7 Bcf</th>
<th>8 Bcf</th>
<th>10 Bcf</th>
</tr>
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<tbody>
<tr>
<td>48%</td>
<td></td>
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<tr>
<td>67%</td>
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<tr>
<td>91%</td>
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</table>

<table>
<thead>
<tr>
<th>NPV0 (BT $MM)</th>
<th>7 Bcf</th>
<th>8 Bcf</th>
<th>10 Bcf</th>
</tr>
</thead>
<tbody>
<tr>
<td>$12.4</td>
<td></td>
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<tr>
<td>$15.3</td>
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<tr>
<td>$19.4</td>
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</table>

<table>
<thead>
<tr>
<th>NPV10 (BT $MM)</th>
<th>7 Bcf</th>
<th>8 Bcf</th>
<th>10 Bcf</th>
</tr>
</thead>
<tbody>
<tr>
<td>$5.0</td>
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<tr>
<td>$6.7</td>
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<tr>
<td>$8.7</td>
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<table>
<thead>
<tr>
<th>Net PIR0 (x)</th>
<th>7 Bcf</th>
<th>8 Bcf</th>
<th>10 Bcf</th>
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<tbody>
<tr>
<td>2.4</td>
<td></td>
<td></td>
<td></td>
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<tr>
<td>2.9</td>
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<tr>
<td>3.7</td>
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<table>
<thead>
<tr>
<th>Net PIR10 (x)</th>
<th>7 Bcf</th>
<th>8 Bcf</th>
<th>10 Bcf</th>
</tr>
</thead>
<tbody>
<tr>
<td>1.0</td>
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<tr>
<td>1.3</td>
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<tr>
<td>1.7</td>
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<table>
<thead>
<tr>
<th>Gas Supply Cost (AECO $/GJ)</th>
<th>7 Bcf</th>
<th>8 Bcf</th>
<th>10 Bcf</th>
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<tbody>
<tr>
<td>$0.55</td>
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<tr>
<td>$0.34</td>
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<td></td>
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<tr>
<td>$0.18</td>
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</table>

<table>
<thead>
<tr>
<th>Condensate Supply Cost (Edm. $/Bbl)</th>
<th>7 Bcf</th>
<th>8 Bcf</th>
<th>10 Bcf</th>
</tr>
</thead>
<tbody>
<tr>
<td>$33.81</td>
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<tr>
<td>$28.00</td>
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<tr>
<td>$22.97</td>
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</tbody>
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<table>
<thead>
<tr>
<th>Payout (months)</th>
<th>7 Bcf</th>
<th>8 Bcf</th>
<th>10 Bcf</th>
</tr>
</thead>
<tbody>
<tr>
<td>21</td>
<td></td>
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<td></td>
</tr>
<tr>
<td>16</td>
<td></td>
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<td></td>
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<tr>
<td>12</td>
<td></td>
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</tr>
</tbody>
</table>

- **Economics at low gas prices supported by strong liquids volumes; material uplift on returns from underlying condensate production**
- **Increase recoverable resource and strengthen associated economics through technological advancements**

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1. See advisories and definitions on pages 33 and 34 hereof.
2. Based on flat pricing. -$0.20/GJ Station 2 differential, and 0.75 US$/C$ FX.

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**Single Well Sensitivities\(^{(2)}\)**

- AECO $1.60/GJ WTI US$50.00/Bbl Not Escalated
- AECO $1.90/GJ WTI US$55.00/Bbl Not Escalated
- AECO $2.20/GJ WTI US$60.00/Bbl Not Escalated

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Consistent Liquids-Rich Production Growth Since Inception(1)

- Inception-to-date liquids of 50 Bbl/MMcf (sales)(3)
  - High value condensate consistently exceeds 70% of liquids volumes
- Liquids yield has stabilized at attractive levels
  - Recoveries vary depending on third party processing facilities

<table>
<thead>
<tr>
<th>Product</th>
<th>2016 Q4</th>
<th>2017 Q4</th>
<th>2018 Q4</th>
<th>2019 Q4</th>
</tr>
</thead>
<tbody>
<tr>
<td>Natural Gas</td>
<td>4,000</td>
<td>8,000</td>
<td>12,000</td>
<td>16,000</td>
</tr>
<tr>
<td>Oil &amp; Condensate</td>
<td>12,000</td>
<td>16,000</td>
<td>20,000</td>
<td>20,000</td>
</tr>
<tr>
<td>Butane</td>
<td>2,000</td>
<td>4,000</td>
<td>6,000</td>
<td>8,000</td>
</tr>
<tr>
<td>Propane</td>
<td>3,000</td>
<td>6,000</td>
<td>9,000</td>
<td>12,000</td>
</tr>
</tbody>
</table>

- Q4 2019 production of 17,738 Boe/d(2)
  - 5 new wells onstream late November 2019
  - 2019 exit production of 20,516 Boe/d(2)
- Brought 2 new wells onstream in the first quarter of 2020

1. See advisories and definitions on pages 33 and 34 hereof.
2. Q4 2019 production consisted of 81 MMcf/d of natural gas, 3,106 Bbl/d of oil and condensate, and 1,149 Bbl/d of natural gas liquids (propane and butane). 2019 exit production consisted of 91 MMcf/d of natural gas, 4,017 Bbl/d of oil and condensate, and 1,279 Bbl/d of natural gas liquids (propane and butane).
3. Inception to December 31, 2019.
Strengthening Netbacks During a Period of Low Commodity Prices\(^{(1),(2)}\)

1. See advisories on pages 33 and 34 hereof.
2. Operating netback is calculated as the difference between the revenue per Boe and related costs (royalties, operating costs, and transportation); includes hedging gains and losses realized in each quarter.

- Saguaro has achieved a competitive 2019 operating netback of $16.92 per Boe despite the challenged commodity price environment.
Extensive Natural Gas Risk Management Program\(^{(1)(2)}\)

- Production volumes aligned with current risk management program
- Program utilizes both financial hedging and marketing contracts
- Marketing contracts include:
  - ~21,400 MMBtu/d Sumas less US$0.73/MMBtu in 2020 followed by ~8,300 MMBtu/d Sumas less US$0.80/MMBtu in 2021 with custody transfer at Station 2
  - ~19,000 MMBtu/d Chicago Citygate less US$1.39/MMBtu to October 2020 with custody transfer at NorthRiver Midstream Highway and McMahon plant

1. See advisories on pages 33 and 34 hereof. See page 31 for additional information. Summary of hedges and physical contracts by type as at March 30, 2020.
2. Figures not adjusted for Saguaro heating value of 1,175 Btu/scf.
Full Development Plan with Substantial Long Term Growth\(^{(1),(2)}\)

- Full development plan allows production growth to a peak of ~215,000 Boe/d (~1 Bcf/d Sales) in 2029
  - Production can be maintained at this level for 10 years
  - Assumes ~1,400 Third Generation HZ wells
  - Results from wells with 40 stage Open Hole Ball Drop completions support an 8 Bcf type curve which has been reflected in the full development plan

1. See advisories on pages 33 and 34 hereof. See page 22 for additional information.
2. 1,400 well development program which develops ~98% of Saguaro’s existing land base and assumes $8.5 B of capital. This FDP is based on 2020 YTD results and will continue to be updated throughout the delineation phase.
3. 2018 average annual production consisted of 76 MMcf/d of natural gas, 2,752 Bbl/d of oil and condensate, and 1,008 Bbl/d of natural gas liquids (propane and butane). 2019 average annual production consisted of 78 MMcf/d of natural gas, 2,629 Bbl/d of oil and condensate, and 1,133 Bbl/d of natural gas liquids (propane and butane).
## Funding Long Term Growth while Maintaining Reasonable Debt Metrics \(^{(1)(2)(3)}\)

**Dynamic development program flexible with market conditions**

**Capital program increasingly funded by cash flow**
- 2020 capital budget driven by expected cash flows

**$155 MM syndicated bank revolver redetermined December 2019**
- $130 MM drawn as at December 31, 2019

**$50 MM 8.5% second lien secured notes, due in 2022**

### Full Development Plan \(^{(4)}\)

<table>
<thead>
<tr>
<th>Capital ($B)</th>
<th>IRR (BT %)</th>
<th>Net PIR0 (x)</th>
<th>Net PIR10 (x)</th>
<th>NPV0 (BT $B)</th>
<th>NPV10 (BT $B)</th>
</tr>
</thead>
<tbody>
<tr>
<td>$8.5</td>
<td>50%</td>
<td>2.4</td>
<td>1.1</td>
<td>$19.2</td>
<td>$3.2</td>
</tr>
</tbody>
</table>

### Debt / Last 12 Months EBITDA

<table>
<thead>
<tr>
<th>Year</th>
<th>Debt/EBITDA</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>3.9x</td>
</tr>
<tr>
<td>2014</td>
<td>3.4x</td>
</tr>
<tr>
<td>2015</td>
<td>2.7x</td>
</tr>
<tr>
<td>2016</td>
<td>2.4x</td>
</tr>
<tr>
<td>2017</td>
<td>1.6x</td>
</tr>
<tr>
<td>2018</td>
<td>1.5x</td>
</tr>
<tr>
<td>2019</td>
<td>1.3x</td>
</tr>
<tr>
<td>2020</td>
<td>0.8x</td>
</tr>
<tr>
<td>2021</td>
<td>0.4x</td>
</tr>
</tbody>
</table>

### Debt / Next 12 Months EBITDA

<table>
<thead>
<tr>
<th>Year</th>
<th>Debt/EBITDA</th>
</tr>
</thead>
<tbody>
<tr>
<td>2013</td>
<td>3.5x</td>
</tr>
<tr>
<td>2014</td>
<td>3.0x</td>
</tr>
<tr>
<td>2015</td>
<td>1.8x</td>
</tr>
<tr>
<td>2016</td>
<td>1.1x</td>
</tr>
<tr>
<td>2017</td>
<td>1.0x</td>
</tr>
<tr>
<td>2018</td>
<td>0.9x</td>
</tr>
<tr>
<td>2019</td>
<td>0.8x</td>
</tr>
<tr>
<td>2020</td>
<td>0.7x</td>
</tr>
<tr>
<td>2021</td>
<td>0.3x</td>
</tr>
</tbody>
</table>

1. See advisories and definitions on pages 33 and 34 hereof. See page 21 for additional information.
2. FDP is based on a 1,400 well development program which develops ~98% of Saguaro’s existing land base. Assumes 2,500 m HZ wells and an 8 Bcf type curve. FDP is based on 2020 YTD results and will continue to be updated throughout the delineation phase. Any changes to the assumptions used in the FDP will impact the metrics and results including amount of equity raised.
3. 202.6 MM shares outstanding.
4. FDP capital includes all development capital (inclusive from 2013; undiscouned), excluding land. Economic metrics for FDP based on - $0.20/GJ Station 2 differential and 0.75 US$/C$ FX; $1.75/GJ AECO and US$55/Bbl WTI in 2020; $2.00/GJ AECO and US$55/Bbl WTI in 2021; then escalated at 1.5% thereafter. Natural Gas Liquids pricing relative to WTI based on average of IQRE pricing. Economic metrics are based on go forward assumptions. IRR does not include land costs and undeveloped land value.
Third Party Processing & Transportation

Third Party Processing

- Currently connected to three third party processing facilities
  - Contracted firm service: 104 MMcf/d effective January 2020
  - Significant interruptible service is also available

Transportation

- Firm service on Enbridge T-North pipeline expanding with processing commitments
- Firm shipper on TC Energy North Montney Mainline project (in-service first half 2020) and Enbridge T-South (in-service ~2021)
- Additional expansions planned for NGTL and Alliance systems
- 49 km 6” condensate pipeline from Saguaro’s facility to truck terminal on the Alaska Highway

1. See advisories on pages 33 and 34 hereof.
Expanding North American Market Access\(^{(1)}\)

- Physically connected to five gas pricing hubs across North America (AECO, Station 2, Sumas, Chicago, and Dawn)
- Financial hedging contracts in place to access additional markets including Henry Hub (NYMEX Natural Gas) and Cushing, OK (WTI)

1. See advisories on pages 33 and 34 hereof.
Strategically Positioned for LNG Upside Potential

- Global LNG demand expected to grow significantly
  - From 42 Bcf/d in 2018\(^2\) to ~82 Bcf/d by 2035\(^3\)
- Ideally positioned to provide substantial long-term natural gas supply to West Coast LNG projects
  - LNG Canada project will require a total of ~4 Bcf/d of natural gas supply should both Phase 1 and Phase 2 proceed
    - Phase 1 approved and expected onstream earliest 2023
    - Phase 2 pending FID
  - Coastal GasLink pipeline to LNG Canada under construction
- Canada, and the Montney specifically, has a competitive advantage to address the supply gap with growing Asian markets expected to account for ~2/3 of LNG demand by 2035\(^3\)
  - Compound annual growth in Asia demand of 3%\(^3\)

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1. See advisories on pages 33 and 34 hereof.
Track Record of Environmental, Social & Governance Responsibility

**Environmental**

- Lowered GHG/Boe emissions 42% since 2015
  - Replaced diesel on pad sites with natural gas
  - 3,000 litres/day of diesel saved during drilling and ~30,000 litres/well saved during completions
  - Pad tie-in prior to fracking eliminates flaring
  - Pad site power generation using Stirling engine vs. raw natural gas, reduces emissions ~70%(2)
  - 6” condensate pipeline reduces diesel required for condensate trucking by ~850,000 litres/year

- Efficient recycling and transportation of water
  - ~1.5 MMBbl of water storage managed at centralized water handling facility which recycles 98% of all water
  - Water distribution system reduces trucking of completion fluids
    - Newly constructed 8” 56-E water pipeline eliminated trucking 3,500 loads of water during Q4 2019 completions

- Minimal land disturbance for pad sites
  - A single conventional vertical well consumes ~10,000 m² of surface area compared to ~3,000 m² for an unconventional Saguaro well

- Industry leading LMR of 30.69 compared to peer average of 16.09(3)
  - On track to meet requirements of OGC’s Dormant Sites Program

**Social & Governance**

- "Safety is not a matter of chance. It is a matter of choice. We take safety personally.” (4)
- Track annual safety metrics
  - Linked to performance goals for all employees

- Focused & accountable Board of Directors meet on a quarterly basis to ensure all policies, procedures, and mandates are adhered to
  - Independent Board Chair; three additional independent directors
  - Three independently chaired committees
    - Audit, HSE & Reserves, Compensation & Corporate Governance
  - TSX Venture compliant shareholder reporting, including quarterly Financial Statements and MD&A

- Contribute to the communities in which we operate
  - Provide First Nations employment and business opportunities
  - Active engagement with First Nations and area stakeholders
  - Sponsorship of NE BC heritage events and investment in local communities
  - Corporate giving initiatives including annual sponsor of STARS Air Ambulance

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1. See advisories and definitions on pages 33 and 34 hereof.
2. Per 2019 Qnergy publication “PowerGen Shines at Remote BC Facility”.
4. Excerpt from Saguaro Resources Environmental, Health & Safety Policy.
5. Total Recordable Injury Frequency = (Recordable Injuries * 200,000 Hours) / Hours Worked.
Saguaro’s Value Proposition

- **Experienced management team has consistently delivered material, capital efficient growth since inception in 2012**
  - Advancing continuous improvement initiatives to enhance well productivity and cost structure

- **Competitive economics achievable in a sustained low commodity price environment**
  - Condensate production supports economics and diversifies sources of revenue

- **Large, high-quality asset in one of North America’s leading oil and gas plays**
  - Unique reservoir in the Montney with high permeability, shallow depth, and stable liquids-rich stacked potential
  - Full development plan to grow production to ~215,000 Boe/d and sustain at this level for 10 years
  - Ideally positioned to provide substantial long-term natural gas supply to West Coast LNG projects

- **Continued focus on capital discipline and development flexibility with a commitment to responsible and accountable operations**

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1. See advisories on pages 33 and 34 hereof.
Corporate Information

Officers

Stacy Knull  President & Chief Executive Officer
Scott Carrothers  Vice President Finance & Chief Financial Officer
Tannis Gibson  Vice President Geology & Geophysics
Jason Hager  Vice President Drilling & Construction
Cody Smith  Vice President Operations & Facilities
Darcy McLaughlin  Vice President Engineering
Esther Troyan  Vice President Land & Business Development

Directors

Michael Graham  Chairman
James C. (Pep) Lough  Independent Businessman
M. Scott Bratt  Independent Businessman
Robert Chaisson  Independent Businessman
Stacy Knull  President & Chief Executive Officer
Richard Aube  Pine Brook Road Partners LLC
Richard Stoneburner  Pine Brook Road Partners LLC
Ted Maa  Pine Brook Road Partners LLC
Andre Burba  Global Infrastructure Partners
Cameron McVeigh  Camcor Partners Inc.

Auditors

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3100, 111 – 5th Ave SW
Calgary, AB T2P 5L3

Independent Qualified Reserves Evaluator

Sproule Associates Limited
Suite 900, 140 – 4th Ave SW
Calgary, AB T2P 3N3

Legal Counsel

Burnet, Duckworth & Palmer LLP
Suite 2400, 525 – 8th Ave SW
Calgary, AB T2P 1G1

Bankers

Canadian Imperial Bank of Commerce
595 Bay St., 5th Floor, Toronto, ON M5G 2C2

Alberta Treasury Branch
239 - 8th Ave SW, Calgary, AB T2P 1B9

National Bank of Canada
600 De La Gauchetiere St. West, 3th Floor, Montreal, QC H3B 4L2

Royal Bank of Canada
Royal Bank Plaza, 200 Bay Street, Toronto, ON M5J 2J5

Business Development Bank of Canada
5, Place Ville Marie, Suite 400, Montreal, QC H3B 5E7

Head Office

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Calgary, AB T2P 0B4
Phone: (403) 453-3040
Fax: (403) 452-3129
Website: www.saguaroresources.com

For more information, please contact

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President & Chief Executive Officer
Phone: (403) 453-2680
Email: sknull@saguaroresources.com

Scott Carrothers
Vice President Finance & Chief Financial Officer
Phone: (403) 453-2451
Email: scarrothers@saguaroresources.com
### Reserves Evaluations\(^{(1)}\)

<table>
<thead>
<tr>
<th>(Company Gross)</th>
<th>Reserves(^{(2)(3)}) (MBoe)</th>
<th>NPV10 per Boe (BT $/Boe)</th>
<th>Locations (#)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proved Developed Producing (PDP)</td>
<td>15,822</td>
<td>31,215</td>
<td>33,247</td>
</tr>
<tr>
<td>Total Proved (1P)</td>
<td>83,541</td>
<td>149,769</td>
<td>152,157</td>
</tr>
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</table>

<table>
<thead>
<tr>
<th>(Company Gross)</th>
<th>Full Development Capital ($MM)</th>
<th>Finding &amp; Development Costs(^{(4)}) ($/Boe)</th>
<th>Finding, Development &amp; Acquisitions Costs(^{(4)}) ($/Boe)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Proved Developed Producing (PDP)</td>
<td>$0</td>
<td>$0</td>
<td>$0</td>
</tr>
<tr>
<td>Total Proved (1P)</td>
<td>$511</td>
<td>$757</td>
<td>$730</td>
</tr>
<tr>
<td>Total Proved Plus Probable (2P)</td>
<td>$1,543</td>
<td>$1,839</td>
<td>$1,886</td>
</tr>
</tbody>
</table>

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2. YE 2016 PDP reserves are comprised of 75% Conventional Natural Gas, 24% Natural Gas Liquids, 1% Light and Medium Crude Oil. 1P and 2P reserves are comprised of 76% Conventional Natural Gas, 24% Natural Gas Liquids.


4. Development Capital of $88.6 MM. Inception to YE 2019 (ITD) Development Capital of $702.0 MM or $762.3 MM including land and acquisition. FD&A and F&D includes FDC.
## Risk Management – Hedging and Marketing Contracts

<table>
<thead>
<tr>
<th></th>
<th>Weighted Average Price</th>
<th>Average Volume</th>
<th>Term(3)</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Financial</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>NYMEX Swap</td>
<td>C$2.862/GJ</td>
<td>64,977 GJ/d</td>
<td>2020</td>
</tr>
<tr>
<td></td>
<td>C$3.324/GJ</td>
<td>20,000 GJ/d</td>
<td>2021</td>
</tr>
<tr>
<td>AECO Swap</td>
<td>C$1.780/GJ</td>
<td>10,000 GJ/d</td>
<td>4Q 2020</td>
</tr>
<tr>
<td></td>
<td>C$2.061/GJ</td>
<td>5,000 GJ/d</td>
<td>2021</td>
</tr>
<tr>
<td>Call on NYMEX Swap</td>
<td>C$3.500/GJ</td>
<td>5,000 GJ/d</td>
<td>1H 2019</td>
</tr>
<tr>
<td>NYMEK / AECO Basis Swap</td>
<td>-C$1.380/GJ</td>
<td>72,486 GJ/d</td>
<td>2020</td>
</tr>
<tr>
<td></td>
<td>-C$1.347/GJ</td>
<td>50,000 GJ/d</td>
<td>2021</td>
</tr>
<tr>
<td>AECO / Station 2 Basis Swap</td>
<td>-C$0.224/GJ</td>
<td>74,167 GJ/d</td>
<td>2020</td>
</tr>
<tr>
<td></td>
<td>-C$0.114/GJ</td>
<td>50,000 GJ/d</td>
<td>2021</td>
</tr>
<tr>
<td></td>
<td>-C$0.086/GJ</td>
<td>27,500 GJ/d</td>
<td>2022</td>
</tr>
<tr>
<td>CAD WTI Swap</td>
<td>C$77.24/Bbl</td>
<td>1,982 Bbl/d</td>
<td>2020</td>
</tr>
<tr>
<td>USD WTI Swap</td>
<td>US$56.70/Bbl</td>
<td>250 Bbl/d</td>
<td>1H 2020</td>
</tr>
<tr>
<td>USD Edmonton Condensate Differential Swap</td>
<td>-US$0.55/Bbl</td>
<td>750 Bbl/d</td>
<td>1H 2020</td>
</tr>
<tr>
<td><strong>Physical &amp; Marketing</strong></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Sumas Marketing Contract</td>
<td>Sumas less US$0.733/MMBtu</td>
<td>21,413 MMBtu/d</td>
<td>2020</td>
</tr>
<tr>
<td></td>
<td>Sumas less US$0.800/MMBtu</td>
<td>8,329 MMBtu/d</td>
<td>2021</td>
</tr>
<tr>
<td>Chicago Marketing Contract</td>
<td>Chicago less US$1.390/MMBtu</td>
<td>15,797 MMBtu/d</td>
<td>2020</td>
</tr>
</tbody>
</table>

---

1. See advisories on pages 33 and 34 hereof.
2. Summary of hedges and physical contracts by type as at March 30, 2020. Does not detail each transaction.
3. Annualized volumes based on a combination of full and partial years, unless specified.
Well Performance Update\(^{(1)(2)}\)

1. See advisories on pages 33 and 34 hereof.
2. See page 16 for single well economics.
3. Pilot program included Lower, Middle and Upper targets.
Advisories

No Obligation to Update. The forward looking statements or information contained in this Presentation are made as of the date hereof and the Corporation undertakes no obligation to update publicly or revise any forward looking statements or information, whether as a result of new information, future events or otherwise unless required by applicable securities laws. The forward looking statements or information contained in this Presentation are expressly qualified by this cautionary statement.

Future Oriented Financial Information. This Presentation contains information that is future oriented financial information ("FOFI"). Similar to forward looking statements or forward looking information under applicable securities legislation. Such forward looking statements or information are provided in this Presentation to assist in an investor's decision with respect to the Corporation and the Corporation believes that the FOFI has been prepared on a reasonable basis, reflecting management's best estimates and judgments. The actual results of operations of the Corporation and the resulting financial results will likely vary from the amounts set forth in the analysis presented in this Presentation, and such variation may be material. The Corporation and its management believe that the FOFI has been prepared on a reasonable basis, reflecting management's best estimates and judgments. However, investors should be cautioned that the FOFI is not necessarily indicative of future results. Except as required by applicable securities laws, the Corporation undertakes no obligation to update such FOFI and forward looking statements and information.

This presentation includes "EBITDA" and "operating netback" which are non-GAAP measures, as further described herein. Non-GAAP measures do not have standardized meaning prescribed by International Financial Reporting Standards and therefore may not be comparable with the calculation of similar measures by other companies. "EBITDA" represents earnings before interest, tax, depreciation and amortization. See Note 2 on page 19 for further information on operating netback.

Oil and Gas Advisories

Future Drilling Locations. Unless otherwise expressly stated, the information in this Presentation pertaining to future drilling locations or drilling inventories is based solely on internal estimates made by management and such locations have not been reflected in any independent reserve or resource evaluations by any external parties. Internal estimates for future drilling locations are based on internal drilling decisions, the Corporation seeks to target drilling locations that, based on previous drilling results and its own internal assessments, it believes will on average ultimately generate favorable results. This document discloses drilling locations which are unbooked locations with undeveloped acreage. Future drilling locations and drilling inventory are based on the Corporation's current and ongoing internal evaluation of the Corporation's drilling program. The Corporation's internal evaluation of its drilling program takes into account a number of factors, including geological characteristics of the reservoir, presence of hydrocarbons, timing of investment, and other factors. However, the Corporation cannot give any assurance that it will drill all unbooked exploration locations and if drilled there is no guarantee that the location will yield hydrocarbons. The Corporation reserves the right to change the drilling program at any time without notice.

Finding and Development Costs. The aggregate and the trend of decrease of costs incurred for the exploration and development activities included in this presentation will depend on the level of costs experienced in the year in which the estimated future development costs will generally will not reflect total finding and development costs related to unbooked locations and are internal estimates based on the Corporation's prospective acreage and an assumption as to the number of wells to be drilled. The assumptions have been made regarding, among other things: commodity prices, the presence of hydrocarbons, timing of development, resource evaluation, and information. There is no assurance that the Corporation will drill all unbooked drilling locations and if drilled there is no guarantee that the location will yield hydrocarbons. The Corporation reserves the right to change the drilling program at any time without notice.
Reserves and Resources. Some of the reserve estimates disclosed on pages 6, 9, and 30 were prepared by Sproule Associates Limited with an effective date of December 31, 2014, July 31, 2015, December 31, 2015, June 30, 2016, September 30, 2016, December 31, 2016, June 30, 2017, October 31, 2017, January 31, 2018, March 31, 2018, December 31, 2018 and/or December 31, 2019 in accordance with NI 51-101 and the COGE Handbook and using Sproule’s forecast prices at December 31, 2014, July 31, 2015, December 31, 2015, June 30, 2016, September 30, 2016, December 31, 2016, May 31, 2017, September 30, 2017, December 31, 2017, March 31, 2018, December 31, 2018 and/or December 31, 2019 respectively. Other than some of the reserves estimates disclosed on pages 6, 9, and 30, the recovery and reserves estimates provided herein are Saguaro’s internal estimates only and are not derived from an independent reserves evaluation prepared pursuant to NI 51-101. There is no guarantee that the reserves or resources will be recovered. As a consequence, actual results may differ materially from those anticipated in the forward looking statements. "EOR" is not indicative of reserves, nor is it a category of resources recognized by the COGE Handbook. Estimates of the net present value of the future net revenue from Saguaro’s reserves do not represent the fair market value of Saguaro’s reserves. Some of the resources estimates disclosed on pages 6, 9, and 30 were prepared by Sproule Associates Limited with an effective date of October 31, 2017 in accordance with NI 51-101 and the COGE Handbook and using Sproule’s forecast prices at September 30, 2017. Such resources estimates were not prepared pursuant to NI 51-101 and therefore do not represent estimated proved reserves or commercial reserves or resources. There is no certainty that any portion of the unestimated resources will be discovered. If discovered, there is no certainty that it will be commercially viable to recover any portion thereof. There is uncertainty that it will be commercially viable to produce any portion of the contingent resources. Reserves and resource estimates contained herein have been made assuming that funding is likely to be available to Saguaro for the development of the applicable property.

Definitions of Oil and Gas Resources and 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 remaining quantities 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.
- Possible Reserves are those additional reserves that are less certain to be recovered than probable reserves. It is unlikely that the actual remaining quantities recovered will exceed the sum of the estimated proved plus probable plus possible reserves.

Resources encompasses all petroleum quantities that originally existed on or within the earth’s crust in naturally occurring accumulations, including discovered and undiscovered (recoverable and unrecoverable) plus quantities already produced. Resources are classified in the following categories:

- Contingent Resources are those additional reserves that are less certain to be recovered than 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.
- Prospective Resources are those petroleum quantities estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Such estimates are subject to further risk and definition.

Pay Thickness. Estimates of pay thickness are considered to be anticipated results or information that indicate the potential value or quantities of resources under NI 51-101. Such estimates have been prepared by management of Saguaro and have not been prepared or reviewed by an independent qualified reserves evaluator or auditor. The risks associated with estimates of pay thickness include, but are not limited to, the risk that Saguaro’s exploration and development drilling and related activities may provide different results; the risk that Saguaro may encounter unexpected drilling results; the occurrence of unexpected events involved in the exploration for, and the operation and development of, oil and gas; delays in anticipated timing of drilling and completion of wells; geological, technical, drilling and processing problems and other difficulties in producing petroleum reserves.

Boe Presentation. All Boe conversions in the report are derived by converting gas to oil at the ratio of six thousand cubic feet of natural gas to one barrel of oil equivalent. Boe may be misleading, particularly if used in isolation. A Boe conversion rate of 1 Boe: 6 Mcf is based on an energy equivalent ratio of 1 Boe to 6 Mcf, utilizing a conversion ratio may be misleading.

Definitions

- certain oil and gas metrics. Finding, development and acquisition costs, finding and development costs, and netbacks do not have standardized meanings or standard methods of calculation and therefore such measures may not be comparable to similar measures used by other companies and should not be used to make comparisons. Such metrics have been included in documents provided by Saguaro to shareholders to give readers additional measures to evaluate the Saguaro’s performance; however, such measures are not reliable indicators of the future performance of the Saguaro and future performance may not compare to the performance in previous periods and therefore such metrics should not be unduly relied upon.

Net Present Value (NPV). The anticipated net present value of the future net revenue (before tax) discounted at a rate (NPV0 for undiscounted future net revenue and NPV10 for future net revenue discounted by 10%) associated with the type curves presented.

IRR: Rate of return. IRR is the discount rate required to arrive at a NPV equal to zero. Rates of return set forth in this presentation are illustrative purposes. There is no guarantee that such rates of return will be achieved in the future.

Profit to Investment Ratio (PIR): The ratio of profit to investment for the project. For example, a net PIR (PIR) for undiscounted future cash flow discounted at 10% of $1.50 represents for every $1.00 of investment, the project will return the invested $1.00 plus an additional $1.50 of profit for a total cash flow of $2.50. The net PIR of such a project would be $1.50 while the gross PIR would be $2.50.

Netback: Price less royalties, operating expenses and transportation costs.

EUR: Estimated Ultimate Recovery. An approximation of the quantity of oil or gas that is potentially recoverable from a well or well field.

Supply Cost: Price required to create an IRR (Before Tax) of 10% assuming the price is held flat over the life of the project (Natural gas price at AECO, Condensate price at Edmonton).

Finding and Development Costs (F&D): The anticipated full exploration and development costs associated with each barrel of oil equivalent expected to be recovered from a well based on the type curves and economics presented.

Finding, Development and Acquisition Costs (FD&A): The anticipated full exploration, development and acquisition costs associated with each barrel of oil equivalent expected to be recovered from a well based on the type curves and economics presented.

IP30: The average production rate over a 30 day period.