"A PROUD CANADIAN CLEAN ENERGY PRODUCER FOCUSED ON DEVELOPMENT OF ITS SIGNIFICANT MONTNEY NATURAL GAS AND LIQUIDS RESOURCE"
CANADIAN E&P COMPANIES – CHALLENGING TIMES BUT...
...“THERE’S MORE THAN MEETS THE EYE” WHEN YOU LOOK BEYOND THE NEGATIVE INDUSTRY HEADLINES
Are AECO gas prices of Cdn $1.50/GJ to $1.75/GJ for the next 4 to 5 years reasonable?
CANADIAN NATURAL GAS SUPPLY REQUIRES HIGHER PRICES TO SUSTAIN AND GROW

Estimated WCSB Break-Even Prices by Sub-Play (1)

Low break-even production plays can add more volume, but there is an upper limit.

The basin still needs lean gas volumes from the Montney and Deep Basin.

We estimate that the curve shifts up $0.25 to $0.75/mmbtu for full-cycle break-evens.

Majority of Canadian Gas Plays Require Full Cycle Prices > C$2.00/mmbtu to Break-Even. Oil and Ultra-rich gas plays are not sufficient to replace Basin declines.

Note: (1) Scotia March 2018 Report, “The AECO Equation”.

Source: Scotiabank GBM estimates.
ASSOCIATED GAS FROM ONLY OIL AND LIQUIDS-RICH GAS PLAYS CHALLENGED TO REPLACE CANADIAN GAS PRODUCTION DECLINES

Figure 2: Total Western Canadian Dry Gas Production Associated vs. Dry Gas

“...we believe the decline in natural gas production will offset most of the associated gas from liquids-rich drilling” (1)

Annual gas production decline is ≈ 4 Bcf/d

Sources: geoSCOUT and Peters & Co. Limited estimates.

NORTH AMERICAN NATURAL GAS DEMAND GROWTH EXPECTED TO OFFSET SMALL SUPPLY IMBALANCE NEAR TERM

North American Natural Gas Market Fundamentals

Recent 0.5 to 0.7 Bcf/d NGTL receipt swings moved prices $0.00 to $1.80/GJ (implies small imbalance?)

Demand greater than Production

Note: Data from Industry Sources
WCSB TRANSPORTATION EGRESS IS GROWING

- 2.0-2.5 Bcf/d of Incremental egress capacity growth in WCSB 2018-2021
- Canadian LNG exports would create significant demand & additional egress
- Significant intra-AB demand expected from oilsands & power generation

**TCPL East Gate:** + 1.7 Bcf/d 2018 - 2021

**TCPL West Gate:** + 0.29 Bcf/d 2019

**T-South:** + 0.19 Bcf/d 2019

**Joliet Express Open Season:** + 0.8 Bcf/d 2021

**Alliance PL Open Season:** + 0.4 Bcf/d 2021

**Jordan Cove**

**Westcoast LNG**

Source: Tudor Pickering Holt & Co
POSITIVE CANADIAN ENERGY MESSAGES GAINING TRACTION – PUBLIC/POLITICAL SUPPORT & NARRATIVE GROWING
ADVANTAGE UPSIDE – “MORE THAN MEETS THE EYE”

- TCFs of Natural Gas
- Millions of Barrels of Liquids including C5+, Oil
- Investment Plan underway to Increase Liquids, Moderate gas
- Operating flexibility to readily modify capital allocation
- Lowest Montney total corporate cash costs
- Access/Market Diversification in place
- Strong Balance Sheet
- Execution Track Record
SIGNIFICANT NATURAL GAS AND LIQUIDS UPSIDE ACROSS LAND HOLDINGS

- 200 net sections (128,000 net acres)
- 110 net sections Progress, Valhalla, Wembley
- Only 169 dry gas Upper & Lower Glacier wells drilled to date (7 standing wells)
- Only 48 liquids rich wells drilled to date (13 standing wells)
- >1,200 future locations (Glacier & Valhalla only)
- 100% Ownership of Glacier gas plant and infrastructure with 400 mmcf/d, 6,800 bbls/d C3+ liquids retains spare capacity for development of AAV’s land blocks

NOTE: Liquid yields indicated are propane plus ("C3+") based on a Glacier shallow cut liquids extraction process
EXTENSIVE LIQUIDS-RICH MONTNEY RESOURCE

Source: Canadian Discovery Digest/Advantage

Recent Advantage Evaluation/Delineation wells drilled within last 18 months

Increasing Total C3+ and C5+/Oil liquids content from East Glacier to Wembley

Only 4% of liquids rich lands have been drilled

Multi-layer Montney development potential
WEMBLEY/PIPESTONE – ULTRA RICH LIQUIDS PRODUCTION

AAV First Wembley Well 12-25 Mid Montney
1,312 boe/d
624 bbls/d free C5+/Oil
819 bbls/d C3+
2.9 mmcf/d

Average Initial Production (boe/d) Average over 1-Year Production (boe/d) TOTAL EUR (boe)

<table>
<thead>
<tr>
<th></th>
<th>Oil</th>
<th>Gas</th>
<th>NGL</th>
<th>Total</th>
<th>Liquid Yield Bbls/mmcf</th>
</tr>
</thead>
<tbody>
<tr>
<td>Average Initial Production (boe/d)</td>
<td>581</td>
<td>409</td>
<td>160</td>
<td>1,150</td>
<td>300</td>
</tr>
<tr>
<td>Average over 1-Year Production (boe/d)</td>
<td>303</td>
<td>260</td>
<td>101</td>
<td>664</td>
<td>260</td>
</tr>
<tr>
<td>TOTAL EUR (boe)</td>
<td>361,000</td>
<td>384,000</td>
<td>150,000</td>
<td>895,000</td>
<td>225</td>
</tr>
</tbody>
</table>
VALHALLA LIQUIDS RICH DEVELOPMENT UNDERWAY

AAV 4 well pad - 6,410 boe/d (32 mmcf/d gas\(^{(1)}\) + 1,075 bbls/d liquids with certain yields up to 100 bbls/mmcf, 90% C5+/oil)

4 well pad – Upper & Middle Montney

Wells will be production restricted to Glacier until new compressor station and liquids handling facility installed Q4 2018

Follow-up drilling includes 5 well pad in H2 2018

Note: (1) Estimated productivity at 3,000 Kpa based on last measured test rate

Evaluated tighter frac spacing. 38-55m spacing along wellbore (31-44m spacing based on principle stress direction)
**Advantage’s First Delineation Well 13-31-77-9W6**

- Lateral Length 2,313 meters
- 44 frac stages
- 624 boe/d average rate (2.7 mmcf/d gas)
- 75 bbls/d free condensate/oil (45 deg API)
- 172 bbls/d C3+ liquids (shallow cut)
- Wellhead (free) C5+ 28 bbls/mmcf
- C3+ 63 bbls/mmcf
- Only 13% load fluid recovered
- Production increasing over test period 40% reservoir draw down during flow up production casing
- Limited testing time due to lack of area process capacity
Evaluating options to transport and process production from our land blocks to Advantage’s 100% owned Glacier gas plant & assessing additional options with midstream and area producers.
## Well Economics Across Advantage Land Holdings

### Half-cycle Economics

**(AECO Cdn $2.00/mcf & $US 60/bbl WTI)**

<table>
<thead>
<tr>
<th></th>
<th>ROR%</th>
<th>Payout Years</th>
<th>Breakeven&lt;sup&gt;(4)&lt;/sup&gt;</th>
</tr>
</thead>
<tbody>
<tr>
<td>Glacier Dry (Upper &amp; Lower Montney)</td>
<td>33% - 67%</td>
<td>1.7 - 2.8</td>
<td>$1.25/mcf</td>
</tr>
<tr>
<td>East Glacier/Valhalla Liquids Rich</td>
<td>40% - 90%</td>
<td>1.4 – 2.2</td>
<td>&lt;$1.00/mcf (AECO Cdn$)</td>
</tr>
<tr>
<td>Wembley</td>
<td>160% - 200%</td>
<td>0.8 – 1.0</td>
<td>&lt;$1.00/mcf (AECO Cdn$)</td>
</tr>
</tbody>
</table>

1) Management estimates. NPV 10% pre-tax.
2) Capital of $4.8 million per well for Glacier and Valhalla and $6.5 million per well for Wembley based on management’s estimate of DCE+T capital cost and includes a 4 month drill to on-production timeframe.
3) Natural gas and NGL prices and costs escalated at 1.5%, based on $60 U.S./bbl WTI.
4) Breakeven based on NPV10 equal to zero at a WTI U.S. $60/bbl and calculated AECO Cdn price.
INCREASING LIQUIDS STRENGTHENS REVENUE & NETBACKS\(^{(1)(2)}\)
(SENSITIVITIES + IMPACTS)

1% Liquids increase ≈ 3% to 5% of Total Revenue Impact

### Liquids Production

<table>
<thead>
<tr>
<th>Year</th>
<th>2018 Guidance</th>
<th>2018 Exit</th>
<th>2019</th>
<th>2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>%</td>
<td>4.4%</td>
<td>5% - 6%</td>
<td>6% - 8%</td>
<td>10% - 15%</td>
</tr>
</tbody>
</table>

### Annual Liquids Revenue ($ Millions)

<table>
<thead>
<tr>
<th>Year</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>Millions</td>
<td>$45</td>
<td>$58 - $65</td>
<td>$100 - $125</td>
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### Annual Liquids Revenue % of Total Revenue

<table>
<thead>
<tr>
<th>Year</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>%</td>
<td>20%</td>
<td>21% - 24%</td>
<td>30% - 38%</td>
</tr>
</tbody>
</table>

### Cash Flow Netbacks (Excluding Hedging)

<table>
<thead>
<tr>
<th>Year</th>
<th>2018</th>
<th>2019</th>
<th>2020</th>
</tr>
</thead>
<tbody>
<tr>
<td>$\text{Netbacks}$</td>
<td>$1.30</td>
<td>$1.64 - $1.68</td>
<td>$1.80 - $2.00</td>
</tr>
</tbody>
</table>

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(1) 2018 prices at strip as of April 24, 2018 and then $2 AECO, $2.55 US/mcf Dawn and WTI $60US/bbl for 2019 and 2020 at Fx $0.79.

(2) Management estimate
Evaluating Longer Laterals and More Frac Stages (up to 2880 meters and 28 frac stages)

Wells producing at ~10 mmcf/d after 365 days – exceeding type curve

1.3 year payout at Cdn $2.00/mcf gas price
Top Tier LM wells

Evaluating Shorter Laterals Spacing & Recovery (1,656 meters)

Production updated to December, 2017
MARKET & REVENUE DIVERSIFICATION PROVIDES OPTIONALITY (~25% REVENUE EXPOSURE TO AECO PRICES THRU 2020)

**Revenue Diversification**

- **2018E**
  - 18% Liquids
  - 4% Midwest U.S.
  - 27% Henry Hub
  - 30% Dawn

- **2019E**
  - 23% Liquids
  - 7% Midwest U.S.
  - 8% Henry Hub
  - 22% Dawn

- **2020E**
  - 37% Liquids
  - 12% Midwest U.S.
  - 5% Henry Hub
  - 21% Dawn

**Increasing Liquids Revenue**

Dawn, U.S. Midwest & Henry Hub enhances commercial portfolio

Hedging discipline protects cash flow volatility

**AECO exposure 25% through 2019**

Notes:
(1) Graph represents % of estimated revenue based on strip pricing at May 10, 2018.
(2) Includes Dawn hedges of 30,000 mmbtu/d at an average price of US $2.86/mmbtu for 2018 and 6,250 mmbtu/d at an average price of US $3.13/mmbtu for 2019
(3) Includes AECO hedges of 81,680 mmcf/d at avg price of AECO Cdn $2.59/mcf 2018 and 39,217 mmcf/d at avg price of $2.71/mcf 2019
MAINTENANCE CAPITAL AND SURPLUS CASH FLOW SENSITIVITY ILLUSTRATIVE AT 280 MMCFE/D (Q4 2018)

(No Hedging Included)

**Capable of Maintaining Production at AECO $1.20/mcf**

**Annual Surplus Cash of $100 million**

**Cash Flow at AECO $2.50/Mcf**

**CASH FLOW $215 Million**

**MAINTENANCE CAPITAL $115 Million**

**CASH FLOW $115 Million**

Notes:

(1) Assumes 7.5 mmcf/d /7.5 Bcf for Upper/Lower Montney wells and 5.0 mmcf/d /5.0 Bcf for Middle Montney wells

(2) Assumes Dawn at $3.30/mcf and a WTI price of $55 US/bbl.
Expansion to 400 mmcf/d Underway

Room for Additional Expansion Beyond 400 mmcf/d

Expansion from 250 mmcf/d to 400 mmcf/d Dry & Liquids gas processing capacity

Glacier Gas Plant Site near Major Natural Gas & Liquids Pipelines & Rail Access

Existing Sales Pipeline capacity of 400 mmcf/d (Glacier plant to NW TCPL Mainline) with Connection to Alliance pipeline Q4 2018
ENVIRONMENT, SOCIAL, HEALTH & SAFETY

**COR Certification**

- 97% 98% 96% 98% 98% 98%
- Top Decile Among Peers

<table>
<thead>
<tr>
<th>Year</th>
<th>2012</th>
<th>2013</th>
<th>2014</th>
<th>2015</th>
<th>2016</th>
<th>2017</th>
</tr>
</thead>
</table>

**Sequestered 40,000 tonnes of CO2 emissions (equivalent to 1,300 vehicles)** from our CO2 & H2S reinjection process at our Glacier gas plant

**Community Support**

**Glacier Gas Plant among top 10 largest E&P plants – single footprint minimizes environmental impact**

- Advantage (72 of 108 companies)
- AER Liability Management Rating: 26.2
  - Advantage: 4.6
  - Industry Average: 1.0
  - Industry Threshold: 1.0

Note: As of December 2, 2017.
Select Montney and Marcellus Natural Gas Producers Cash Costs
2018 Estimates (Cdn$/mcfe)

<table>
<thead>
<tr>
<th></th>
<th>Operating costs &amp; transportation ($/mcfe)</th>
<th>Royalties incl. GCA adjustments ($/mcfe)</th>
<th>G&amp;A ($/mcfe)</th>
<th>Interest &amp; other ($/mcfe)</th>
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<tbody>
<tr>
<td>AAV&lt;sup&gt;(1)&lt;/sup&gt;</td>
<td>$1.18</td>
<td></td>
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</tr>
<tr>
<td>Montney&lt;sup&gt;(2)&lt;/sup&gt;</td>
<td>$2.39</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Marcellus&lt;sup&gt;(3)&lt;/sup&gt;</td>
<td>$2.82</td>
<td></td>
<td></td>
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</table>

(1) Advantage 2018 estimates at April 26, 2018.
(2) RBC Capital Markets 2018 average cost estimate including ARX, BIR, CR, KEL, NVA, PPY, POU, TOU and VII at April 12, 2018.
(3) Tudor, Pickering, Holt & Co. 2018 average cost estimate including AR, CNX, COG, EQT, RICE and RRC at April 26, 2018 using a USD$/CAD$ foreign exchange rate of $0.78.
PROVIDING CLEAN ENERGY & EVERYDAY NECESSITIES FOR YOU
Certain statements contained in this presentation constitute forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as “seek”, “anticipate”, “plan”, “continue”, “estimate”, “expect”, “may”, “will”, “project”, “predict”, “potential”, “targeting”, “intend”, “could”, “might”, “should”, “believe” and similar expressions. In particular, this presentation contains forward-looking statements pertaining to, but not limited to, the following: details of the Corporation’s 2015 to 2017 development plan including expected production growth, estimate debt to cash flow ratio, expected capital expenditures, expected wells to be drilled, expected operating costs, expected economics, expected resulting free cash flow and expected number of drilling locations and inventory; expected number of wells required to be drilled to achieve certain levels of production; expected details and timing of the Glacier gas plant expansion; expected well economics associated with certain type curves; expected future production levels; expected sensitivities in cash flow per share and debt to cash flow levels to changes in commodity prices; expected effect of refining of drilling and completion technique; Advantage’s guidance in respect of anticipated production levels, exit production rates, royalty rates, operating costs and netbacks; and projections of market prices and costs. In addition, statements relating to “reserves” or “resources” are deemed to be forward-looking statements, as they involve the implied assessment, based on certain estimates and assumptions that the reserves and resources described can be profitably produced in the future. These statements involve substantial known and unknown risks and uncertainties, certain of which are beyond Advantage’s control, including, but not limited to: changes in general economic, market and business conditions; industry conditions; actions by governmental or regulatory authorities including increasing taxes or royalties; and changes in investment or other regulations; the effect of acquisitions; Advantage’s success at acquisition, exploitation and development of reserves; changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; fluctuations in commodity prices and foreign exchange and interest rates; stock market volatility and market valuations; volatility in market prices for oil and natural gas; unexpected drilling results, changes in commodity prices, currency exchange rates, capital expenditures, reserves or reserves estimates and debt service requirements; the occurrence of unexpected events involved in the exploration for, and the operation and development of, oil and gas properties; hazards such as fire, explosion, blowouts, cratering, and spills, each of which could result in substantial damage to wells, production facilities, other property and the environment or in personal injury; changes or fluctuations in production levels; delays in anticipated timing of drilling and completion of wells; individual well productivity; competition from other producers; the lack of availability of qualified personnel or management; credit risk; our ability to comply with current and future environmental or other laws; liabilities inherent in oil and natural gas operations; uncertainties associated with estimating oil and natural gas reserves; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; incorrect assessments of the value of acquisitions; geological, technical, drilling and processing problems and other difficulties in producing petroleum reserves; ability to obtain required approvals of regulatory authorities; ability to access sufficient capital from internal and external sources. Many of these risks and uncertainties and additional risk factors are described in the Corporation’s Annual Information Form which is available at www.sedar.com and www.advantageog.com. Readers are also referred to risk factors described in other documents Advantage files with Canadian securities authorities. With respect to forward-looking statements contained in this presentation, Advantage has made assumptions regarding, but not limited to: conditions in general economic and financial markets; effects of regulation by governmental agencies; current commodity prices and royalty regimes; future exchange rates; royalty rates; future operating costs; current commodity prices and royalty regimes; availability of skilled labor; availability of drilling and related equipment; timing and amount of capital expenditures; the impact of increasing competition; the price of crude oil and natural gas; that the Corporation will have sufficient cash flow, debt or equity sources or other financial resources required to fund its capital and operating expenditures and requirements as needed; that the Corporation’s conduct and results of operations will be consistent with its expectations; that the Corporation will have the ability to develop the Corporation’s properties in the manner currently contemplated; current or, where applicable, proposed assumed industry conditions, laws and regulations will continue in effect or as anticipated; and the estimates of the Corporation’s production and reserves volumes and the assumptions related thereto (including commodity prices and development costs) are accurate in all material respects.

Advantage’s actual decisions, activities, results, performance or achievement could differ materially from those expressed in, or implied by, such forward-looking statements and, accordingly, no assurances can be given that any of the events anticipated by the forward-looking statements will transpire or occur or, if any of them do, what benefits that Advantage will derive from them. Except as required by law, Advantage undertakes no obligation to publicly update or revise any forward-looking statements. For additional risk factors in respect of Advantage and its business, please refer to its Annual Information Form dated March 25, 2015 which is available on SEDAR at www.sedar.com and www.advantageog.com.

References in this presentation to initial test production rates, production type curves, initial “productivity”, initial “flow” rates, final gas flow rates, average gas flow rates, average type curves, “flush” production rates and “30 day IP rates” and other short-term production rates are useful in confirming the presence of hydrocarbons, however such rates are not
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determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or of ultimate recovery. While encouraging, readers are cautioned not to place reliance on such rates in calculating the aggregate production for Advantage. A pressure transient analysis or well-test interpretation has not been carried out in respect of all wells. Accordingly, the Corporation cautions that the test results should be considered to be preliminary.

Certain type curves presented herein represent estimates of the production decline and ultimate volumes expected to be recovered from wells over the life of the well. The 7.2 mmcf/d IP (which represents the average 30 day initial production rate) & 7.2 Bcf (which represents the ultimate volumes expected to be recovered from the wells over the life of the well based on the type curve) Upper and Lower Montney type curve and the 4.5 mmcf/d IP and 4.5 Bcf Middle Montney type curve are management generated type curves based on a combination of historical performance of older wells and management’s expectation of what might be achieved from future wells. The type curves represent what management thinks an average well will achieve. Individual wells may be higher or lower but over a larger number of wells management expects the average to come out to the type curve. Over time type curves can and will change based on achieving more production history on older wells or more recent completion information on newer wells.

Other type curves presented herein, including the 9 mmcf/d IP & 9 Bcf Upper and Lower Montney type curve have been provided to demonstrate the economics associated with wells that could potentially have that type of productivity and recovery but do not represent management estimates of how such wells will actually perform.

This presentation discloses certain future drilling locations that have not been booked in Advantage’s most recent independent reserves evaluation as prepared by Sproule as of December 31, 2015. Such drilling locations are internal estimates based on Advantage’s prospective acreage and an assumption as to the number of wells that can be drilled per section based on industry practice and internal review. Such locations do not have attributed reserves or resources. Such drilling locations have been identified by management as an estimation of our multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Advantage will drill all 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 we actually drill 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 drilling locations have been derisked by drilling existing wells in relative close proximity to such drilling locations, other drilling locations are farther away from existing wells where management has less information about the characteristics of the reservoir and therefore there is more uncertainty whether wells will be drilled in such locations and if drilled there is more uncertainty that such wells will result in additional oil and gas reserves, resources or production.

Throughout this presentation the terms boe (barrels of oil equivalent), mcfe (thousand cubic feet of gas equivalent), mmmcfe (millions of cubic feet of gas equivalent), bcf (billions of cubic feet of gas equivalent) and Tcfe (trillion of cubic feet of gas equivalent) are used. Such terms may be misleading, particularly if used in isolation. The conversion ratio used herein of six thousand cubic feet per barrel (6 mcf: 1 bbl) of natural gas to barrels of oil equivalent and the conversion ratio used herein of 1 barrel per six thousand cubic feet (1 bbl: 6 mcf) of barrels of oil to natural gas equivalent 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.

The Corporation discloses several financial measures that do not have any standardized meaning prescribed under International Financial Reporting Standards (“IFRS”). These financial measures include funds from operations, total debt to cash flow ratio and operating netbacks. Management believes that these financial measures are useful supplemental information to analyze operating performance and provide an indication of the results generated by the Corporation’s principal business activities. Investors should be cautioned that these measures should not be construed as an alternative to net income, cash provided by operating activities or other measures of financial performance as determined in accordance with IFRS. Advantage’s method of calculating these measures may differ from other companies, and accordingly, they may not be comparable to similar measures used by other companies. Funds from operations, as presented, is based on cash provided by operating activities, adjusted for expenditures on decommissioning liability, changes in non-cash working capital and interest on bank indebtedness. Total debt to cash flow ratio is calculated as indebtedness under Advantage’s credit facilities plus working capital deficit divided by funds from operations. Operating netbacks are calculated by deducting royalties and operating costs from revenue on a unit (boe or mcfe) basis. Please see the Corporation’s most recent Management’s Discussion and Analysis, which is available at www.sedar.com and www.advantageoq.com for additional information about certain of these financial measures, including a reconciliation of funds from operations to cash provided by operating activities.
The following abbreviations used in this press release, including in the appendices hereto, have the meanings set forth below:

<table>
<thead>
<tr>
<th>Abbreviation</th>
<th>Meaning</th>
</tr>
</thead>
<tbody>
<tr>
<td>bbls</td>
<td>barrels</td>
</tr>
<tr>
<td>bbls/d</td>
<td>barrels per day</td>
</tr>
<tr>
<td>mbbls</td>
<td>thousand barrels</td>
</tr>
<tr>
<td>boe</td>
<td>barrels of oil equivalent of natural gas, on the basis of 1 barrel of oil or NGLs for 6 thousand cubic feet of natural gas</td>
</tr>
<tr>
<td>mboe</td>
<td>thousands of barrels of oil equivalent</td>
</tr>
<tr>
<td>boe/d</td>
<td>barrels of oil equivalent per day</td>
</tr>
<tr>
<td>2P</td>
<td>proved plus probable reserves</td>
</tr>
<tr>
<td>NGLs</td>
<td>natural gas liquids</td>
</tr>
<tr>
<td>mcf</td>
<td>thousand cubic feet</td>
</tr>
<tr>
<td>mmcf</td>
<td>million cubic feet</td>
</tr>
<tr>
<td>mmcf/d</td>
<td>million cubic feet per day</td>
</tr>
<tr>
<td>bcf</td>
<td>billion cubic feet</td>
</tr>
<tr>
<td>bcfe</td>
<td>billion cubic feet of natural gas equivalent on the basis of 1 barrel of oil or NGLs to 6 thousand cubic feet of natural gas</td>
</tr>
<tr>
<td>tcf</td>
<td>trillion cubic feet</td>
</tr>
<tr>
<td>tce</td>
<td>trillion cubic feet of natural gas equivalent on the basis of 1 barrel of oil to 6 thousand cubic feet of natural gas</td>
</tr>
</tbody>
</table>

Where any disclosure of reserves data and resources is made in this presentation that does not reflect all reserves of Advantage, the reader should note that the estimates of reserves, future net revenue and resources for individual properties or groups of 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.

This presentation includes calculations of finding and development ("F&D") costs which have been calculated in accordance with Section 5.15 of NI 51-101 by adding together exploration costs, development costs and the change in future development costs and dividing the sum by reserves additions. The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

In this presentation certain financial and operating metrics of other issuers are presented to compare such metrics to Advantage’s results. Such other issuers were included to show how Advantage’s performance compares to some of its peers. The financial and operating metrics of such issuers have been obtained from public sources and have not been independently verified by Advantage. Readers should not base an investment decision for the securities of such issuers based on the information available herein. Advantage disclaims any responsibility or liability for the accuracy of the information relating to such other issuers presented herein.

This presentation contains projections of production growth based on drilling and recompletion opportunities identified by management of Advantage. Certain of the drilling opportunities identified have no associated reserves or resources which can presently be classified as recoverable. As such the initial rates of production and reserves per well identified herein do not represent estimates of future production or reserves associated with the drilling opportunities. The initial rates of production, reserves per well and the capital costs associated with drilling and recompletion identified below are based on Advantage’s historical results and analogous public information received from other producers using similar technologies as Advantage intends to use in the same or similar areas and formations. The initial rates of production, reserves per well and capital costs associated with the wells have been provided herein to give an indication of management’s assumptions used for budgeting, planning and forecasting purposes. The initial rates of production, reserves and capital costs will most likely be different than projected.