CALGARY, ALBERTA--(Marketwired - Apr 4, 2017) - Leucrotta Exploration Inc. ("Leucrotta" or the "Company") (TSX VENTURE:LXE) is pleased to announce it has completed its infrastructure project to tie-in 4 previously drilled delineation wells and has drilled 3 additional step-out /delineation wells that materially further extend the productive boundaries of the Company's Lower Montney Turbidite Light Oil Resource Play (see Company map in Appendix 1).

PRODUCTION

As a result of the tie-in of four wells, Leucrotta has increased production to over 3,000 boepd (25% oil and ngls).This excludes two new Montney wells (8-4 and 12-06) that are tested but not tied-in and one well (13-07) that is temporarily shut-in due to third party restrictions.

Leucrotta completed the main gathering lines to connect 3 Lower Montney Turbidite wells to its plant in Q117. The Lower Montney wells are comprised of 2 wells in the oil window (8-22 and 8-18) and one in the liquids-rich gas window (13-19).

The 8-22 well was drilled and completed in early 2016 as a high GOR light oil well in the Lower Montney Turbidite Light Oil Pool and had a previously released test rate of 713 boepd (49% liquids).(1) The well was placed on production in February 2017 and had an IP30 of 671 boepd (244 boepd light oil and condensate, 2.3 mmcf/d gas and 41 boepd of ngls) (42% oil and liquids). Leucrotta's independent reserve evaluator, GLJ Petroleum consultants ("GLJ"), assigned 671 mboe of reserves to this well.(2)

The 8-18 well was drilled and completed in Q4 2014 as a Lower Montney Turbidite well and had a previously released test rate of 371 boepd (25 % oil and liquids).(1) The well was placed on production in February 2017 and had an IP30 of 401 boepd (157 boepd light oil and condensate, 1.3 mmcf/d gas and 24 boepd of ngls) (45% oil and liquids). The material increase in oil production on the IP30 versus the initial test rates is a phenomenon that has been observed in all of Leucrotta's Lower Montney Turbidite oil wells drilled to date. Leucrotta had originally mapped this well in the liquids-rich gas window due to the low ratio of oil /condensate in the original test but the quality of the oil (42 API) and well performance clearly places this well in the light oil window. GLJ assigned 450 mboe of reserves to this well.(2)

The 13-07 Lower Montney Turbidite Light Oil well was put on production in 2015 and has now produced over 16 months. This well had a previously released test rate of 472 boepd (49% oil and liquids)(1), had an IP30 of 495 boepd (322 boepd light oil and condensate, 0.96 mmcf/d gas and 13 boepd of ngls), and was still producing 255 boepd (24% oil and liquids) after 16 months of production prior to being shut -in. GLJ assigned an ultimate recovery of 705 mboe to this well.(3)

The A4-19 Upper Montney liquids-rich gas well (1% sour content) was placed on production in February 2017 through a third party facility and since that date had an IP30 of 793 boepd (12% liquids). GLJ assigned 780 mboes ultimate recovery to this well.(3)

DRILLING EXTENSIONS AND DELINEATION OF THE MONTNEY LOWER TURBIDITE LIGHT OIL POOL

Leucrotta has recently drilled three wells that have materially extended and delineated the boundaries of the Lower Montney Turbidite Light Oil Resource Play.

The 8-4 well was drilled 5.2 km north and west of the 8-22 well noted above. The well encountered light oil in the Lower Montney turbidite zone. The well was tested over a 7 day period with an average production of 1060 boepd (524 boepd light oil and condensate, 2.9 mmcf/d gas and 52 boepd of ngls) (54% oil and liquids).(4) Given the magnitude of the step-out from the 8-22, this well materially extends the known productive boundary of the light oil field through a significant portion of Leucrotta-owned Montney acreage to the north.

A vertical stratigraphic test was drilled at 4-30 north of the Peace River. Located 7.4 km northwest of the 8-4 well, the well was logged and cored in the Upper, Middle and Lower Montney. Also high resolution logs and mud gas isotopes were collected from the complete Montney section. The well encountered 55 metres of pay in the Lower Montney with core porosities on par with the core porosities in the 13-7 well. All three northern wells (8-04, 13-07, and 4-30 have similar log characteristics with estimated average porosity of 5.5%. The 4-30 vertical well confirms the geological mapping and oil charge of a major northern extension of the Lower Montney Turbidite Light Oil Resource Play. Analysis of Upper and Middle Montney in the 4-30 wellbore are more fully described in the following section titled "Stacked Montney Zones Provide Additional Exploration and Development".

The 12-06 well was drilled 11.7 kms south of the 13-07 oil well and 4.4 kms north of the 13-19 liquids-rich gas well. The well encountered oil pay and was tested over a 7 day period with average production of 550 boepd (221 boepd light oil and condensate, 1.8 mmcf/d gas and 32 boepd of ngls, 46% oil and liquids).(4) This well confirms the mapped boundaries of the light oil window to be further south than Leucrotta had originally mapped.

A summary of production data for the Lower Montney Light Oil wells is as follows:

Lower Montney Oil Wells	Test Rate Average (boepd)	Liquids %	IP30 Average (boepd)	Liquids %	IP90 Average (boepd)	Liquids %
8-22	713	49	671	42	n/a	n/a
8-18	371	25	401	45	n/a	n/a
13-7	472	49	495	67	379	54
8-4	1,060	54	n/a	n/a	n/a	n/a
12-6	550	46	n/a	n/a	n/a	n/a

The extension of the productive boundaries of the Lower Montney Turbidite Light Oil Resource Play are viewed as materially positive by Leucrotta for various reasons including:

- Reduced exposure to natural gas egress issues in Canada
- Increased exposure to oil and condensate prices
- Reduced long-term capital expenditures for gas plant processing equipment
- Reduced pipeline and transportation commitments

Leucrotta's Montney wells were completed with an average 28 stages 55 m stage spacing, 60 tonnes per stage slickwater fracs over an average 1,500 metre lateral horizontal well. The current trend has been a push to increase the frac intensity by significantly increasing the number of stages per well. This trend has been more prevalent in oil reservoirs and could add material upside through increased recoveries and/or acceleration of production. See section titled "Completion Technology and Pad Development".

LOWER MONTNEY RESERVES AND NET PRESENT VALUES PER WELL

GLJ recently reviewed all of Leucrotta's Lower Montney Turbidite wells in conjunction with assigning reserves for the 2016 year-end Reserve Report previously released. While there is variation of reserves assigned across the pool, given different well test rates and gas oil ratios, the average economics are compelling.

For Lower Montney light oil wells, GLJ assigned, on average, 669 mboes (32% oil and ngls) of ultimate recovery per well. Using Leucrotta's current estimated drill and complete costs (before pad development) of $3.8 million, GLJ's average production curve, and GLJ's January 2017 Price Forecast, the average Lower Montney Turbidite light oil well will generate a rate of return of 91% and a net present value (NPV10) of $7.1 million.[5]

For Lower Montney liquids-rich gas wells, GLJ assigned, on average, 1055 mboes (21% oil and ngls) of ultimate recovery per well. Using Leucrotta's current estimated drill and complete costs (before pad development) of $3.8 million, GLJ's average production curve, and GLJ's January 2017 Price Forecast, the average Lower Montney Turbidite liquids-rich gas well will generate a rate of return of 223% and a net present value (NPV10) of $8.7 million.[5]

Leucrotta currently owns approximately 105 net sections of land within its mapped boundaries of the Lower Montney Turbidite play. Current data suggests there are approximately 80 net sections in the oil window and 25 net sections in the liquids-rich gas window. Based on up to 8 wells per section in the oil window and 4 wells per section in the liquids-rich window, Leucrotta has a potential drilling inventory of 640 Lower Montney Turbidite oil wells and 100 Lower Montney Turbidite liquids-rich gas wells.[6]

LOWER MONTNEY TURBIDITE ESTIMATED OOIP AND OGIP

Leucrotta has internally estimated each section in the "oil window" of the Lower Montney to contain approximately 31 million barrels of OOIP and 25 bcf of OGIP. In the "liquids-rich gas window", Leucrotta estimates there is approximately 46 bcf of OGIP per section with a liquids yield of approximately 45 bbls/mmcf.

Based on Leucrotta working interest ownership in approximately 80 net sections in the oil window and 25 net sections in the liquids-rich gas window, there is approximately 2.5 billion barrels of OOIP and 3.1 tcf of OGIP on Leucrotta's land base. This excludes condensate and ngls yields.[7]

STACKED MONTNEY ZONES PROVIDE ADDITIONAL EXPLORATION AND DEVELOPMENT

While Leucrotta has focused its delineation drilling in the Lower Montney Turbidite, there is incremental exploration and development potential in both the Upper and Middle Montney zones on Leucrotta lands.

Upper Montney

At Doe, Leucrotta had previously drilled the A4-19 Upper Montney well for liquids-rich gas that had a recent IP30 of 793 boepd as noted earlier. Other operators immediately offsetting Leucrotta's Doe acreage have recently drilled and tested liquids-rich gas wells in the Upper Montney with test rates exceeding 2,000 boepd.

In addition to Leucrotta's Doe acreage that is already proved productive in the Upper Montney, Leucrotta has been evaluating both the Upper and Middle Montney zones with cores, logs, and geochemical data being collected while drilling its deeper Lower Montney delineation programs. Although the Upper Montney reservoir is thinner than that found to the southwest at Tower, where it produces light sweet oil, hydrocarbon charged quality reservoir is present across Leucrotta's acreage. This reservoir has been confirmed in the cores from the 16-30 and 4-30 wells with an average core porosity of 5.4%. Logs and mud gas geochemistry collected in the Upper Montney while drilling for the Lower Montney zone, also demonstrates this additional potential for liquids-rich gas and light oil across Leucrotta's acreage.

Leucrotta believes an Upper Montney horizontal multi-frac well on its lands outside of the immediate Doe area may be economic to drill and would be a significant addition to its Lower Montney Play. Leucrotta does not have plans to drill a test well in 2017.

Middle Montney

Leucrotta cored the middle Montney in its 4-30 vertical well. Average core porosity is 6.1% and the core fluid saturations and mud gas geochemistry indicates that it is potentially oil charged. The closest core data or production test on the Middle Montney is at Pouce Coupe, approximately 30 km away. The data is encouraging and Leucrotta's mapping indicates that the zone is present across a large portion of its acreage. A horizontal well would be considered exploratory at this point and Leucrotta has no plans to drill the Middle Montney in 2017.

COMPLETION TECHNOLOGY AND PAD DEVELOPMENT

Leucrotta has, to date, employed a consistent completion program to allow for comparison of reservoir characteristics in wells over a large geographic area. The typical well has been drilled with a horizontal leg of approximately 1,500 metres and completed with a 28-stage, 55m stage spacing, 60 tonne slickwater frac.

Leucrotta has now completed the initial delineation of the Lower Montney Turbidite and will look to optimize future completions to maximize rates and recoveries particularly in the oil window. The industry trend has been to increase the frac intensity and, in particular, increase the number of stages and the amount of sand placed per metre of wellbore to enhance well productivity. Leucrotta is currently drilling an offset to its 8-22 well and will increase to a 41 stage, 37m stage spacing 60 tonne slickwater frac. This well is expected to be completed and on-stream in early May. If successful, Leucrotta will adopt the increased frac intensity on a go-forward basis.

Leucrotta has not yet moved to pad development, but will be in a position to do so in 2017 and 2018. Pad wells have the advantage of significantly reduced capital costs per well (and increased rate of return) and there is some evidence to support a theory that pad wells in general perform better than individual wells. Leucrotta will look to drill a three-well pad in the oil window sometime in 2017 or 2018.

TAKEAWAY AND PLANT PROCESSING CAPACITY

Leucrotta currently owns and operates a 25 mmcf/d sweet gas plant at Doe and a new refrigeration unit that would allow Leucrotta to expand the sweet plant capacity to approximately 85 mmcf/d for an estimated cost of approximately $15 million. Leucrotta anticipates expanding the plant as necessary in conjunction with increased capital activity expected in 2018.

The Leucrotta plant is currently connected to the Alliance Pipeline with current firm capacity of 15 mmcf/d for 2017 and increasing to 23 mmcf/d for 2018 and 33 mmcf/d for 2019-20.

Oil and condensate are currently trucked to area terminals but growing volumes may warrant connection to pipeline in the future.

Leucrotta's gas plant and land base are also located in close proximity to the NGTL and Pembina pipeline systems, providing easier access for both gas and liquids egress.

FINANCIAL

Leucrotta had approximately $14 million of net positive working capital and no debt as at the end of February 2017 (approximately $26 million at December 31, 2016). Based on cash position and estimated cash flow, Leucrotta will be able to carry out its plans to further delineate and develop the Montney in its core area of Doe / Mica in Northeast BC and Northwest Alberta. Leucrotta estimates capital expenditures of approximately $30 million for the remainder of 2017 to continue its development of the Lower Montney. Given current commodity prices, Leucrotta estimates it will exit 2017 with annualized cash flow of approximately $25 million and net debt of approximately $5 million.

SUMMARY

Leucrotta's Lower Montney Turbidite play has several notable characteristics that distinguish it:

- A large portion of Leucrotta's lands fall within the light oil window exposing the Company significantly to light oil upside
- Large OOIP per section will allow for the application of emerging technologies to continually improve well performance and oil recovery percentages
- Drilling costs are relatively moderate given vertical depth of 1,800 to 2,200 metres
- Egress issues are lessened given higher percentage of oil and condensate in relation to gas
- Oil wells, to date, have produced 100% sweet oil and gas and therefore do not require sour processing or extra expenses to treat.
- 100% owned and operated gas plant provides material cost advantage that enhances half-cycle drilling economics
- Doe area has accessible pipelines for both gas and liquids (Alliance Pipeline, Pembina Pipeline, NGTL Pipeline)
- Surface is predominantly farmland with an established grid of roads providing excellent year-round access.

To view Appendix 1: Leucrotta land base / drilling activity map Doe/Mica, BC, please visit the following link: http://media3.marketwire.com/docs/lxe0404appendix1.pdf.

Notes:

(1) *Test Rates for the 8-22 well were disclosed in a press release on February 29, 2016.*

Test Rates for the 8-18 and 13-7 wells were disclosed in a press release on April 7, 2015.

(2) *Proved plus Probable Developed Non-Producing reserves as per the 2016 year-end reserves as independently evaluated by GLJ Petroleum Consultants Ltd. ("GLJ") effective December 31, 2016, in accordance with National Instrument 51-101 ("NI 51-101") and Canadian Oil and Gas Evaluation (COGE) Handbook.*

(3) *Ultimate Recovery is equivalent to EUR - Estimated Ultimate Recovery which is defined as "those quantities of petroleum which are estimated, on a given date, to be potentially recoverable from an accumulation, plus those quantities already produced therefrom."*

(4) *The 8-4-82-14W6 well was production tested for 7 days after the original cleanup and produced at an average rate of 1060 boepd (50% gas, 50% Oil and Condensate) over that period, excluding load fluid and energizing fluid. At the end of the test, flowing wellhead pressure and production rates were stable.*

The 12-6-81-13W6 well was production tested for 7 days after the original cleanup and produced at an average rate of 550 boepd (60% gas, 40% Oil and Condensate) over that period, excluding load fluid and energizing fluid. At the end of the test, flowing wellhead pressure and production rates were stable.

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

(5) *Type Curves - This Presentation contains references to type well, or "type curve", production and economics, which are derived, at least in part, from available information respecting the well performance of other companies and, as such, may be considered "analogous information" as defined in NI 51-101. Production type curves are based on a methodology of analog, empirical and theoretical assessments and workflow with consideration of the specific asset, and as depicted in this presentation, is representative of The Company's current program, including relative to current performance. Some of this data may not have been prepared by qualified reserves evaluators, may have been prepared based on internal estimates, and the preparation of any estimates may not be in strict accordance with COGEH. Estimates by engineering and geo-technical practitioners may vary and the differences may be significant. The Company believes that the provision of this analogous information is relevant to the Company's oil and gas activities, given its acreage position and operations (either ongoing or planned) in the areas in question, and such information has been updated as of the date hereof unless otherwise specified.*

The well economics presented in this press release are an internal estimate prepared by a Qualified Reserves Evaluator ("QRE") and are based on an average of the proved plus probable type curves used by GLJ for booked undeveloped horizontal wells in the Lower Montney formation as per the year-end 2016 corporate reserves evaluation effective December 31, 2016. The curves represent an internal "best-estimate" expectation.

(6) *Potential Drilling Locations - This press release discloses drilling locations in four categories: (i) proved undeveloped locations; (ii) probable undeveloped locations; (iii) unbooked locations; and (iv) an aggregate total of (i), (ii) and (iii).*

Of the 640 total potential/possible Lower Montney oil locations referenced in this press release, only the following have been assigned reserves at December 31, 2016 as independently evaluated by GLJ, in accordance with National Instrument 51-101 ("NI 51-101"):

• *1 Proved Undeveloped*

• *2 Probable Undeveloped*

The remaining 637 potential/possible locations are unbooked.

Of the 100 total potential/possible Lower Montney liquids-rich gas locations referenced in this press release, only the following have been assigned reserves at December 31, 2016 as independently evaluated by GLJ, in accordance with National Instrument 51-101 ("NI 51-101"):

• 4 Proved Undeveloped

• 6 Probable Undeveloped

The remaining 90 potential/possible locations are unbooked.

Unbooked locations are based on the Company's prospective acreage and internal estimates as to the number of wells that can be drilled per section. Unbooked locations do not have attributed reserves or resources (including contingent and prospective). Unbooked locations have been identified by management as an estimation of the Company's multi-year drilling activities based on evaluation of applicable geologic, seismic, engineering, production and reserves information. There is no certainty that the Company will drill all unbooked drilling locations and if drilled there is no certainty that such locations will result in additional oil and gas reserves, resources or production. The drilling locations on which the Company will actually drill wells, including the number and timing thereof is ultimately dependent upon the availability of funding, regulatory approvals, seasonal restrictions, oil and natural gas prices, costs, actual drilling results, additional reservoir information that is obtained and other factors. While certain of the unbooked drilling locations have been de-risked by drilling existing wells in relative close proximity to such unbooked drilling locations, the majority of other unbooked 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.

(7) OGIP (Original Gas in Place) and OOIP (Original Oil in Place) are equivalent to Total Petroleum Initially In Place ("TPIIP").

TPIIP - as defined in the Canadian Oil and Gas Evaluations Handbook ("COGEH"), is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").There is no certainty that any portion of the resources will be discovered. If discovered, there is no certainty that it will be commercially viable to produce any portion of the resources.

The OGIP and OOIP estimates quoted in this press release are unaudited internal estimates effective March 31, 2017 prepared by a qualified reserves evaluator in accordance with the COGE Handbook. Product type for the OOIP number is "tight oil" and product type for the OGIP number is "shale gas". The location of the resource is the lands depicted in orange on the map in Appendix 1 with the oil / gas boundary as shown on the map. Of the 80 net sections in the oil window, Leucrotta has an average ownership working interest of 91% (87.5 gross sections). Of the 25 net sections in the liquids-rich gas window, Leucrotta's average ownership working interest is 88% (28.5 gross sections). The key variables relevant to the evaluation are porosity, reservoir thickness, pressure, water saturation and gas composition which have increasing uncertainty, both positive and negative, with distance from existing wells.

Currency

All dollar figures are Canadian dollars unless otherwise noted.

BOE Conversions

BOEs may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

NON-GAAP Measures

Net debt includes current liabilities and any borrowings under a credit facility less current assets. Management uses net debt as a measure to assess the Company's financial position.

Unaudited Financial Information

Certain financial and operating results included in this news release such as working capital are based on unaudited estimated results. These estimated results are subject to change upon completion of the audited financial statements for the year ended December 31, 2016, and changes could be material. The Company anticipates filing its audited financial statements and related management's discussion and analysis for the year ended December 31, 2016 on SEDAR on or before April 30, 2017.

Production Rates

Any references to peak rates, test rates, IP30, IP90 or initial production rates or declines are useful for confirming the presence of hydrocarbons, however, such rates and declines are not determinative of the rates at which such wells will commence production and decline thereafter and are not indicative of long term performance or ultimate recovery. IP30 is defined as an average production rate over 30 consecutive days and IP90 is defined as an average production rate over 90 consecutive days. Readers are cautioned not to place reliance on such rates in calculating aggregate production for the Corporation.

Reserves Data

There are numerous uncertainties inherent in estimating quantities of light and medium oil, tight oil, shale gas, conventional natural gas and NGL reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth above are estimates only. In general, estimates of economically recoverable light and medium oil, tight oil, shale gas, conventional natural gas and NGL reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and natural gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially.

Individual properties may not reflect the same confidence level as estimates of reserves for all properties due to the effects of aggregation.

This press release contains estimates of the net present value of the Company's future net revenue from its reserves. Such amounts do not represent the fair market value of the Company's reserves.

The reserves data contained in this press release has been prepared in accordance with NI 51-101. The reserve data provided in this press release presents only a portion of the disclosure required under National Instrument 51-101. All of the required information will be contained in the Company's Annual Information Form for the year ended December 31, 2016, available on SEDAR at www.sedar.com*.*

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

Proved Reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Probable Reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

Oil and Gas Metrics

This new release contains metrics commonly used in the oil and gas industry, such as "NPV" and "OGIP". These terms do not have standardized meanings or standardized methods of calculation and therefore may not be comparable to similar measures presented by other companies. Readers are cautioned that the information provided by these metrics, or that can be derived from the metrics presented in this presentation should not be unduly relied upon. The following oil and gas metrics have the following meanings as used in this press release:

NPV - Net Present Value is defined as "the present value of future cash flows minus the initial capital."

OGIP (Original Gas in Place) and OOIP (Original Oil in Place) are equivalent to Total Petroleum Initially In Place ("TPIIP") TPIIP - as defined in the Canadian Oil and Gas Evaluations Handbook ("COGEH"), is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").

Boe - Barrel of Oil Equivalent. 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 equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. Readers are cautioned that Boe may be misleading, particularly if used in isolation.

Forward-Looking Information

This press release contains forward-looking statements and forward-looking information within the meaning of applicable securities laws. The use of any of the words "expect", "anticipate", "continue", "estimate", "may", "will", "should", "believe", "intends", "forecast", "plans", "guidance" and similar expressions are intended to identify forward-looking statements or information.

More particularly and without limitation, this document contains forward-looking statements and information relating to the Company's oil, NGLs and natural gas production and reserves and reserves values, capital programs, and oil, NGLs, and natural *gas commodity prices. The forward-looking statements and information are based on certain key expectations and assumptions made by the Company, including expectations and assumptions relating to prevailing commodity prices and exchange rates, applicable royalty rates and tax laws, future well production rates, the performance of existing wells, the success of drilling new wells, the availability of capital to undertake planned activities and the availability and cost of labour and services.*

Although the Company believes that the expectations reflected in such forward-looking statements and information are reasonable, it can give no assurance that such expectations will prove to be correct. Since forward-looking statements and information address future events and conditions, by their very nature they involve inherent risks and uncertainties. Actual results may differ materially from those currently anticipated due to a number of factors and risks. These include, but are not limited to, the risks associated with the oil and gas industry in general such as operational risks in development, exploration and production, delays or changes in plans with respect to exploration or development projects or capital expenditures, the uncertainty of estimates and projections relating to production rates, costs and expenses, commodity price and exchange rate fluctuations, marketing and transportation, environmental risks, competition, the ability to access sufficient capital from internal and external sources and changes in tax, royalty and environmental legislation. The forward-looking statements and information contained in this document are made as of the date hereof for the purpose of providing the readers with the Company's expectations for the coming year. The forward-looking statements and information may not be appropriate for other purposes. The Company 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 so required by applicable securities laws.

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