# PATIENCE AT PLAY

LEUCROTTA
EXPLORATION INC.

ANNUAL REPORT **2018**

LEUCROTTA
EXPLORATION INC.

# Q4 2018 FINANCIAL AND OPERATING RESULTS

## HIGHLIGHTS

- Increased production 24% to 3,550 boe/d in 2018 from 2,865 boe/d in 2017.
- Increased adjusted funds flow 66% to $15.9 million in 2018 from $9.6 million in 2017.
- Maintained working capital of $2.1 million.

## FINANCIAL RESULTS

| | Three Months Ended December 31 | | | Year Ended December 31 | | |
|---|---|---|---|---|---|---|
| ($000s, except per share amounts) | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| **Oil and natural gas sales** | **7,113** | 9,301 | (24) | **32,048** | 26,124 | 23 |
| **Cash flow from operating activities** | **3,764** | 3,294 | 14 | **16,249** | 8,311 | 96 |
| Per share - basic and diluted | **0.02** | 0.02 | - | **0.08** | 0.04 | 100 |
| **Adjusted funds flow (1)** | **2,875** | 4,462 | (36) | **15,949** | 9,602 | 66 |
| Per share - basic and diluted | **0.01** | 0.02 | (50) | **0.08** | 0.05 | 60 |
| **Net loss** | **(161)** | (5,072) | (97) | **(43)** | (8,222) | (99) |
| Per share - basic and diluted | **(-)** | (0.03) | (100) | **(-)** | (0.04) | (100) |
| **Net capital expenditures and acquisitions** | **10,665** | 15,870 | (33) | **36,680** | 93,514 | (61) |
| **Working capital** | | | | **2,102** | 18,660 | (89) |
| **Common shares outstanding (000s)** | | | | | | |
| Weighted average - basic and diluted | **200,525** | 200,486 | - | **200,520** | 189,377 | 6 |
| End of period - basic | | | | **200,525** | 200,497 | - |
| End of period - fully diluted | | | | **227,082** | 227,108 | - |

(1) Adjusted funds flow and adjusted funds flow per share do not have any standardized meaning prescribed by International Financial Reporting Standards ("IFRS") and therefore may not be comparable to similar measures used by other companies. Please refer to the "Non-GAAP Measures" section in the MD&A for more details and the "Cash Flow from Operations and Adjusted Funds Flow" section in the MD&A for a reconciliation from cash flow from operating activities.

| OPERATING RESULTS [1] | Three Months Ended December 31 | | | Year Ended December 31 | | |
|---|---|---|---|---|---|---|
| | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| **Daily production** | | | | | | |
| Oil and NGLs (bbls/d) | **850** | 1,290 | (34) | **954** | 820 | 16 |
| Natural gas (mcf/d) | **14,115** | 15,071 | (6) | **15,574** | 12,268 | 27 |
| Oil equivalent (boe/d) | **3,202** | 3,802 | (16) | **3,550** | 2,865 | 24 |
| **Revenue** | | | | | | |
| Oil and NGLs ($/bbl) | **44.78** | 61.44 | (27) | **59.46** | 56.69 | 5 |
| Natural gas ($/mcf) | **2.78** | 1.45 | 92 | **2.00** | 2.05 | (2) |
| Oil equivalent ($/boe) | **24.14** | 26.59 | (9) | **24.74** | 24.98 | (1) |
| **Royalties** | | | | | | |
| Oil and NGLs ($/bbl) | **(0.60)** | 7.64 | (108) | **1.45** | 6.63 | (78) |
| Natural gas ($/mcf) | **-** | 0.04 | (100) | **-** | 0.06 | (100) |
| Oil equivalent ($/boe) | **(0.16)** | 2.75 | (106) | **0.39** | 2.17 | (82) |
| **Net operating expenses [2]** | | | | | | |
| Oil and NGLs ($/bbl) | **5.95** | 6.36 | (6) | **6.67** | 7.51 | (11) |
| Natural gas ($/mcf) | **0.78** | 0.75 | 4 | **0.82** | 0.93 | (12) |
| Oil equivalent ($/boe) | **5.00** | 5.13 | (3) | **5.40** | 6.12 | (12) |
| **Net transportation and marketing expenses [2]** | | | | | | |
| Oil and NGLs ($/bbl) | **1.17** | 2.11 | (45) | **1.54** | 2.69 | (43) |
| Natural gas ($/mcf) | **0.82** | 0.51 | 61 | **0.52** | 0.65 | (20) |
| Oil equivalent ($/boe) | **3.92** | 2.75 | 43 | **2.69** | 3.55 | (24) |
| **Operating netback [2]** | | | | | | |
| Oil and NGLs ($/bbl) | **38.26** | 45.33 | (16) | **49.80** | 39.86 | 25 |
| Natural gas ($/mcf) | **1.18** | 0.15 | 687 | **0.66** | 0.41 | 61 |
| Oil equivalent ($/boe) | **15.38** | 15.96 | (4) | **16.26** | 13.14 | 24 |
| Depletion and depreciation ($/boe) | **(9.29)** | (9.21) | 1 | **(9.38)** | (9.77) | (4) |
| Exploration and evaluation ($/boe) | **-** | (17.84) | (100) | **-** | (5.97) | (100) |
| General and administrative expenses ($/boe) | **(5.48)** | (3.45) | 59 | **(4.05)** | (4.32) | (6) |
| Share based compensation ($/boe) | **(0.84)** | (1.05) | (20) | **(2.81)** | (1.49) | 89 |
| Finance expense ($/boe) | **(0.42)** | (0.32) | 31 | **(0.26)** | (0.27) | (4) |
| Finance income ($/boe) | **0.10** | 0.42 | (76) | **0.21** | 0.48 | (56) |
| Loss on sale of assets ($/boe) | **-** | (1.40) | (100) | **-** | (0.47) | (100) |
| Deferred income tax recovery ($/boe) | **-** | 2.38 | (100) | **-** | 0.80 | (100) |
| **Net loss ($/boe)** | **(0.55)** | (14.51) | (96) | **(0.03)** | (7.87) | (100) |

(1) "bbls" refers to barrels, "mcf" refers to thousand cubic feet, and "boe" refers to barrel of oil equivalent. Disclosure provided herein in respect of a boe may be misleading, particularly if used in isolation. A boe conversion rate of six thousand cubic feet of natural gas to one barrel of oil equivalent has been used for the calculation of boe amounts in the MD&A. This boe conversion rate is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(2) Net operating expenses, net transportation and marketing expenses and operating netback do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. Please refer to the "Non-GAAP Measures" section in the MD&A for more details and the "Net Operating Expenses", "Net Transportation and Marketing Expenses" and "Operating Netback" sections in the MD&A for reconciliations from operating expenses, transportation expenses, and net loss per boe, respectively.

## MANAGEMENT'S DISCUSSION AND ANALYSIS ("MD&A")

April 22, 2019

The MD&A should be read in conjunction with the audited financial statements and related notes for the years ended December 31, 2018 and 2017. The audited financial statements and financial data contained in the MD&A have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). All dollar amounts are expressed in Canadian currency, unless otherwise noted.

### DESCRIPTION OF BUSINESS

Leucrotta Exploration Inc. ("Leucrotta" or the "Company") is an oil and natural gas company, actively engaged in the acquisition, development, exploration, and production of oil and natural gas reserves in northeastern British Columbia, Canada. The Company trades on the TSX Venture Exchange ("TSXV") under the symbol "LXE".

### FREQUENTLY RECURRING TERMS

The Company uses the following frequently recurring industry terms in the MD&A: "bbls" refers to barrels, "mcf" refers to thousand cubic feet, and "boe" refers to barrel of oil equivalent. Disclosure provided herein in respect of a boe may be misleading, particularly if used in isolation. A boe conversion rate of six thousand cubic feet of natural gas to one barrel of oil equivalent has been used for the calculation of boe amounts in the MD&A. This boe conversion rate 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

This MD&A refers to certain financial measures that are not determined in accordance with IFRS (or "GAAP"). This MD&A contains the terms "adjusted funds flow", "adjusted funds flow per share", "operating netback", "net operating expenses", and "net transportation and marketing expenses" which do not have any standardized meaning prescribed by GAAP and therefore may not be comparable to similar measures used by other companies. The Company uses these measures to help evaluate its performance.

Management considers adjusted funds flow to be a key measure as it demonstrates the Company's ability to generate the cash necessary to fund future capital investments and abandonment obligations and to repay debt. Adjusted funds flow is a non-GAAP measure and has been defined by the Company as cash flow from operating activities excluding the change in non-cash working capital related to operating activities and expenditures on decommissioning obligations. The Company also presents adjusted funds flow per share whereby amounts per share are calculated using weighted average shares outstanding, consistent with the calculation of net earnings (loss) per share. Adjusted funds flow is reconciled from cash flow from operating activities under the heading "Cash Flow from Operations and Adjusted Funds Flow".

Management considers operating netback an important measure as it demonstrates its profitability relative to current commodity prices. Operating netback, which is calculated as average unit sales price less royalties, net operating expenses, and net transportation and marketing expenses, represents the cash margin for every barrel of oil equivalent sold. Operating netback per boe is reconciled to net loss per boe under the heading "Operating Netback".

Net operating expenses is calculated as operating expenses less processing revenues. Management uses net operating expenses to determine the current periods' cash cost of operating expenses less processing revenue and net operating expenses per boe is used to measure operating efficiency on a comparative basis. The measure approximates the Company's operating expenses relative to its produced volumes by excluding third party operating costs.

Net transportation and marketing expenses is calculated as transportation expenses less marketing revenues. Management uses net transportation and marketing expenses to determine the current periods' cash cost of transportation expenses less marketing revenue and net transportation and marketing expenses per boe is used to measure transportation efficiency on a comparative basis as well as the Company's ability to mitigate the cost of excess committed capacity.

### UPDATE

In Q4 2018, Leucrotta's capital was spent on the drilling of an Upper Montney well at Mica plus minor pipeline and infrastructure projects. The Montney land base continues to grow with Leucrotta now owning over 220 net sections in a large contiguous block spanning the Doe, Mica and Two Rivers areas.

Production remained relatively stable at 3,200 boe/d for the quarter as wells continue to outperform expectations. Production is estimated to remain fairly flat through-out the first 3 quarters of 2019 with an increase in Q4 2019 as additional Montney wells are placed on production in Q4 2019. Leucrotta's product mix is currently 27% liquids of which 65% of that is light oil and condensate. On a development basis, Leucrotta's product mix would increase to over 40% liquids with focus on the volatile oil window combined with installation of a gas plant with increased liquids extraction.

Operating netbacks for Q4 2018 were stable at $15.38 per boe as compared to 2018 annual average of $16.26 per boe and $14.28 per boe in Q3 2018. Diversification of marketing for gas resulted in Leucrotta netting $2.78 per mcf versus AECO spot price of $1.62 per boe in the quarter but larger differentials on light oil and condensate during the quarter mitigated these gains.

Leucrotta maintained a strong balance sheet at the end of 2018 with $2.1 million net positive working capital and a $20 million credit facility. Leucrotta estimates net working capital of $2.5 million at the end of Q1 2019. Equipment sales improved year-end working capital by $4.3 million with Q1 2019 being increased by an additional $1.6 million.

For the remainder of 2019, Leucrotta will remain conservative and protect the balance sheet given significant volatility seen in both the oil and gas markets. As at the end of Q1 2019, Leucrotta had 4 wells drilled, completed and tested that are not on production and 2 wells that are drilled but not completed. Leucrotta's plans for the rest of the year are to add some of these wells to the production base plus possibly drill one additional delineation well.

Over the past 4 years, Leucrotta has been able to materially de-risk a large light oil resource in the Lower Montney over a minimum of 140 net sections of land and is working to de-risk additional lands for Lower Montney as well as the Upper Montney and Basal Montney (Below Lower Montney) on Leucrotta's land base. Infrastructure currently in place combined with up to 1,000 potential drilling locations[(1)] will allow for Leucrotta to rapidly and materially increase production once the decision is made to move to the development phase.

We look forward to reporting on the results of the new wells and other business developments in the near future.

*(1)* ***Potential Drilling Locations***

*This MD&A 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 1,000 total potential/possible Montney locations referenced in this MD&A, only the following have been assigned reserves at December 31, 2018 as independently evaluated by GLJ, in accordance with NI 51-101:*

- *19 Proved Undeveloped*
- *34 Probable Undeveloped*

*The remaining 947 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 and performed by a Qualified Reserves Evaluator (QRE). 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.*

**SUMMARY OF FINANCIAL RESULTS**

| | **Three Months Ended December 31** | | **Year Ended December 31** | | |
|---|---|---|---|---|---|
| ($000s, except per share amounts) | **2018** | 2017 | **2018** | 2017 | 2016 |
| **Oil and natural gas sales** | **7,113** | 9,301 | **32,048** | 26,124 | 8,844 |
| **Cash flow from (used in) operating activities** | **3,764** | 3,294 | **16,249** | 8,311 | (328) |
| Per share - basic and diluted | **0.02** | 0.02 | **0.08** | 0.04 | (-) |
| **Adjusted funds flow** | **2,875** | 4,462 | **15,949** | 9,602 | (996) |
| Per share - basic and diluted | **0.01** | 0.02 | **0.08** | 0.05 | (0.01) |
| **Net loss** | **(161)** | (5,072) | **(43)** | (8,222) | (12,182) |
| Per share - basic and diluted | **(-)** | (0.03) | **(-)** | (0.04) | (0.07) |
| **Total assets** | | | **317,043** | 313,041 | 241,635 |
| **Total long-term liabilities** | | | **9,572** | 8,718 | 6,820 |
| **Working capital** | | | **2,102** | 18,660 | 26,063 |

The Company experienced an increase in oil and natural gas sales, cash flow from operating activities, adjusted funds flow, and a reduced net loss for the year ended December 31, 2018 compared to 2017 due to production growth from successful drilling at Doe/Mica and lower expenses (royalty, net operating, and net transportation and marketing). The large net loss in Q4 2017 was also attributed to a $6.2 million expense related to non-core exploration and evaluation ("E&E") assets. The decrease in oil and natural gas sales and adjusted funds flow for the fourth quarter of 2018 compared to the fourth quarter of 2017 was mainly the result of lower production and lower oil and NGLs pricing which was partially offset by higher natural gas pricing with increased net transportation and marketing expenses to transport the natural gas to Chicago.

The decrease in working capital from December 31, 2017 to December 31, 2018 stems mainly from $36.7 million of capital expenditures over the past twelve months partially offset by $15.9 million of adjusted funds flow.

| PRODUCTION | Three Months Ended December 31 | | | Year Ended December 31 | | |
|---|---|---|---|---|---|---|
| | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| Average Daily Production | | | | | | |
| Oil and NGLs (bbls/d) | **850** | 1,290 | (34) | **954** | 820 | 16 |
| Natural gas (mcf/d) | **14,115** | 15,071 | (6) | **15,574** | 12,268 | 27 |
| Combined (boe/d) | **3,202** | 3,802 | (16) | **3,550** | 2,865 | 24 |

For the year ended December 31, 2018, production increased to 3,550 boe/d from 2,865 boe/d in 2017. This was the result of successful drilling at Doe/Mica in the second half of 2017 carrying through 2018.

For the three months ended December 31, 2018, production decreased to 3,202 boe/d from 3,802 boe/d for the comparative period in 2017. The decrease in production was the result of flush production in Q4 2017 from successful drilling at Doe/Mica in the second half of 2017 facing natural declines through to the fourth quarter of 2018.

Leucrotta's production profile for the year ended December 31, 2018 remained consistent with 2017. The 2018 weighting was 73% natural gas (December 31, 2017 - 71%) and 27% oil and NGLs (December 31, 2017 - 29%). The fourth quarter of 2018 saw a decrease in liquids weighting from the comparative quarter in 2017. The Q4 2018 weighting was 73% natural gas (Q4 2017 - 66%) and 27% oil and NGLs (Q4 2017 - 34%). This was the result of flush production from new wells put on production in Q4 2017 which declined throughout 2018 thus lowering the liquids weighting.

| OIL AND NATURAL GAS SALES | Three Months Ended December 31 | | | Year Ended December 31 | | |
|---|---|---|---|---|---|---|
| ($000s) | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| Oil and NGLs | **3,500** | 7,292 | (52) | **20,704** | 16,966 | 22 |
| Natural gas | **3,613** | 2,009 | 80 | **11,344** | 9,158 | 24 |
| Total | **7,113** | 9,301 | (24) | **32,048** | 26,124 | 23 |
| | | | | | | |
| Average Sales Price | | | | | | |
| Oil and NGLs ($/bbl) | **44.78** | 61.44 | (27) | **59.46** | 56.69 | 5 |
| Natural gas production sales and transportation revenue ($/mcf) | **2.78** | 1.45 | 92 | **2.00** | 2.05 | (2) |
| Combined ($/boe) | **24.14** | 26.59 | (9) | **24.74** | 24.98 | (1) |

Revenue totaled $7.1 million and $32.0 million for the three months and year ended December 31, 2018, respectively, compared to $9.3 million and $26.1 million for the comparative periods in 2017. The 23% increase for the year ended December 31, 2018 over 2017 was mainly the result of the 24% production growth over the same time period. The fourth quarter of 2018 saw a 24% decline in revenues from the comparative quarter in 2017 stemming from a 16% decline in production and a 9% decrease in commodity prices (27% decrease in oil and NGLs commodity prices partially offset by a 92% increase in natural gas prices).

| PROCESSING AND MARKETING REVENUE | Three Months Ended December 31 | | | Year Ended December 31 | | |
|---|---|---|---|---|---|---|
| ($000s) | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| Sale of purchased natural gas | **-** | 202 | (100) | **361** | 1,838 | (80) |
| Processing revenue | **277** | - | 100 | **884** | - | 100 |
| Marketing revenue | **51** | - | 100 | **507** | - | 100 |
| Total | **328** | 202 | 62 | **1,752** | 1,838 | (5) |

The purchase and sale of natural gas is done to optimize firm transportation capacity. See also "Net transportation and marketing expenses" section.

Marketing revenue relates to unutilized firm transportation assigned to a third party for a contracted fee in which the Company receives a premium.

The following table outlines the Company's realized wellhead prices and industry benchmarks:

| Commodity Pricing | Three Months Ended December 31 | | | Year Ended December 31 | | |
|---|---|---|---|---|---|---|
| | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| **Oil and NGLs** | | | | | | |
| Corporate price ($CDN/bbl) | **44.78** | 61.44 | (27) | **59.46** | 56.69 | 5 |
| Canadian light sweet ($CDN/bbl) | **48.27** | 65.68 | (27) | **68.49** | 61.84 | 11 |
| West Texas Intermediate ("WTI") ($US/bbl) | **58.81** | 55.40 | 6 | **64.77** | 50.95 | 27 |
| **Natural gas** | | | | | | |
| Corporate price ($CDN/mcf) | **2.78** | 1.45 | 92 | **2.00** | 2.05 | (2) |
| AECO price ($CDN/mcf) | **1.62** | 1.72 | (6) | **1.53** | 2.20 | (30) |
| **Exchange rate** | | | | | | |
| $US/$CAD exchange rate | **0.7564** | 0.7871 | (4) | **0.7718** | 0.7712 | - |

Differences between corporate and benchmark prices can be the result of quality differences (higher or lower API oil and higher or lower heat content natural gas), sour content, the mix of oil and NGLs, and various other factors. Leucrotta's differences are mainly the result of a higher proportion of lower priced NGLs and higher heat content natural gas production that is priced higher than AECO reference prices.

The Company's corporate average oil and NGLs prices were 92.8% and 86.8% of Canadian light sweet prices for the three months and year ended December 31, 2018, respectively, consistent with 93.5% and 91.7% for the comparative periods in 2017.

Corporate average natural gas prices were 171.6% and 130.7% of AECO prices for the three months and year ended December 31, 2018, respectively, up from 84.3% and 93.2% for the comparative periods in 2017 mainly due to new marketing contracts with a portion of natural gas sales priced off indexes other than AECO. The Company received AECO pricing plus $0.20/mcf on the first 10,000 mcf/d and ATP pricing on production above this in the Doe/Mica core area from January 2018 to October 2018. From November 2018 to December 2018, the Company received a Chicago indexed pricing on the first 7,000 mcf/d, AECO pricing plus $0.31/mcf on the next 6,000 mcf/d, and ATP pricing on production above this in the Doe/Mica core area.

Leucrotta's liquids mix during the fourth quarter of 2018 was approximately 65% oil, condensate and pentanes, 11% butane and 24% propane (Q4 2017 - 77% oil, condensate and pentanes, 7% butane and 16% propane). The decline in oil weighting in the fourth quarter of 2018 from the comparative quarter in 2017 was mainly the result of flush light oil production in Q4 2017.

Future prices received from the sale of the products may fluctuate as a result of market factors. In addition, the Company may enter into commodity price contracts to help manage future cash flows. The Company does not currently have any commodity price contracts outstanding.

| **ROYALTIES** | **Three Months Ended December 31** | | | **Year Ended December 31** | | |
|---|---|---|---|---|---|---|
| ($000s) | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| Oil and NGLs | **(47)** | 907 | (105) | **506** | 1,986 | (75) |
| Natural gas | **-** | 54 | (100) | **-** | 281 | (100) |
| Total | **(47)** | 961 | (105) | **506** | 2,267 | (78) |
| | | | | | | |
| Average Royalty Rate (% of sales) | | | | | | |
| Oil and NGLs | **(1.3)** | 12.4 | (110) | **2.4** | 11.7 | (79) |
| Natural gas | **-** | 2.7 | (100) | **-** | 3.1 | (100) |
| Combined | **(0.7)** | 10.3 | (107) | **1.6** | 8.7 | (82) |

The Company pays royalties to provincial governments (Crown). Crown royalties are calculated on a sliding scale based on commodity prices and individual well production rates. Royalty rates can change due to commodity price fluctuations and changes in production volumes on a well-by-well basis, subject to a minimum and maximum rate restriction ascribed by the Crown. The provincial government has also enacted various royalty incentive programs that are available for wells that meet certain criteria, such as natural gas deep drilling, which can result in fluctuations in royalty rates.

During the year ended December 31, 2018, the Company began receiving credits to offset royalties from BC's Infrastructure Royalty Credit Program ("IRCP") resulting from infrastructure built in 2017 and wells drilled and tied-into the related infrastructure. During the three months and year ended December 31, 2018, the Company realized $0.4 million and $1.8 million, respectively, of credits to offset royalties payable and has $1.0 million of credits remaining. No infrastructure credits were received in the 2017 comparative periods. Further credits to reduce royalties are expected in the future as royalties continue to be payable on wells already tied-into completed and approved infrastructure projects and as new infrastructure is built and wells are drilled and tied-into related infrastructure that was approved for credits under the program and become royalty payable. The timing of receipt of future credits is dependent on commodity prices and production levels and thus cannot be readily forecast; correspondingly, royalty rates reported in future quarters will vary, likely materially, as these credits are recognized. This credit program is in addition to BC's Natural Gas Deep Well Royalty Credit Program where the Company currently has $1.7 million in remaining royalty credits.

| **NET OPERATING EXPENSES** | **Three Months Ended December 31** | | | **Year Ended December 31** | | |
|---|---|---|---|---|---|---|
| ($000s) | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| Oil and NGLs | **466** | 755 | (38) | **2,322** | 2,248 | 3 |
| Natural gas | **1,284** | 1,042 | 23 | **5,565** | 4,152 | 34 |
| Operating expenses | **1,750** | 1,797 | (3) | **7,887** | 6,400 | 23 |
| Less: processing revenue | **(277)** | - | 100 | **(884)** | - | 100 |
| Net operating expenses (non-GAAP) | **1,473** | 1,797 | (18) | **7,003** | 6,400 | 9 |
| | | | | | | |
| Average net operating expenses | | | | | | |
| Oil and NGLs ($/bbl) | **5.95** | 6.36 | (6) | **6.67** | 7.51 | (11) |
| Natural gas ($/mcf) | **0.78** | 0.75 | 4 | **0.82** | 0.93 | (12) |
| Combined ($/boe) | **5.00** | 5.13 | (3) | **5.40** | 6.12 | (12) |

Per unit net operating expenses were $5.00/boe and $5.40/boe for the three months and year ended December 31, 2018, respectively, compared to $5.13/boe and $6.12/boe in the comparative periods in 2017. The slight decrease was the result of receiving third party processing fees at the Company's Doe gas plant.

| **NET TRANSPORTATION AND MARKETING EXPENSES** | **Three Months Ended December 31** | | | **Year Ended December 31** | | |
|---|---|---|---|---|---|---|
| ($000s) | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| Oil and NGLs transportation | **92** | 251 | (63) | **536** | 805 | (33) |
| Natural gas transportation | **1,116** | 734 | 52 | **3,544** | 3,241 | 9 |
| Transportation expenses | **1,208** | 985 | 23 | **4,080** | 4,046 | 1 |
| Purchased natural gas | **-** | 177 | (100) | **270** | 1,507 | (82) |
| Transportation and marketing expenses | **1,208** | 1,162 | 4 | **4,350** | 5,553 | (22) |
| Less: sale of purchased natural gas | **-** | (202) | (100) | **(361)** | (1,838) | (80) |
| Less: marketing revenue | **(51)** | - | 100 | **(507)** | - | 100 |
| Net transportation and marketing expenses (non-GAAP) | **1,157** | 960 | 21 | **3,482** | 3,715 | (6) |

| Average net transportation and marketing expenses | | | | | | |
|---|---|---|---|---|---|---|
| Oil and NGLs ($/bbl) | **1.17** | 2.11 | (45) | **1.54** | 2.69 | (43) |
| Natural gas ($/mcf) | **0.82** | 0.51 | 61 | **0.52** | 0.65 | (20) |
| Combined ($/boe) | **3.92** | 2.75 | 43 | **2.69** | 3.55 | (24) |

Net transportation and marketing expenses are mainly third-party pipeline tariffs from firm transportation agreements to deliver production to the purchasers at main hubs. Net transportation and marketing expenses decreased to $2.69/boe for the year ended December 31, 2018 compared to $3.55/boe in 2017. Net transportation and marketing expenses increased to $3.92/boe for the three months ended December 31, 2018 compared to $2.75/boe for the comparative period in 2017.

The decrease in oil and NGLs transportation for the three months and year ended December 31, 2018 was the result of different sales points and sales and transportation contracts for new production in Doe/Mica in 2018.

The decrease in per unit natural gas transportation in the year ended December 31, 2018 was mainly due to unutilized firm transportation in Q1 2017. With new wells coming on-stream during Q1 2017, the Company kept more firm transportation but those wells were tied-in later than originally expected. This issue was rectified later in 2017 and into 2018 as the Company was able to predict timing of new wells being tied-in. The 61% increase in per unit natural gas transportation in the fourth quarter of 2018 compared the fourth quarter of 2017 was mainly due to the Company transporting natural gas to Chicago to receive higher Chicago indexed pricing on a portion of the Company's production.

Transportation and marketing expenses includes purchased natural gas while net transportation and marketing expenses includes the sale of purchased natural gas leaving only the net margin in net transportation and marketing expenses. The purchase and sale of natural gas is done to optimize firm transportation capacity. Net transportation and marketing expenses also deduct the marketing revenue the Company generates from the premium received on assigned unutilized firm transportation.

| **OPERATING NETBACK** | **Three Months Ended December 31** | | | **Year Ended December 31** | | |
|---|---|---|---|---|---|---|
| | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| **Oil and NGLs ($/bbl)** | | | | | | |
| Revenue | **44.78** | 61.44 | (27) | **59.46** | 56.69 | 5 |
| Royalties | **0.60** | (7.64) | (108) | **(1.45)** | (6.63) | (78) |
| Net operating expenses | **(5.95)** | (6.36) | (6) | **(6.67)** | (7.51) | (11) |
| Net transportation and marketing expenses | **(1.17)** | (2.11) | (45) | **(1.54)** | (2.69) | (43) |
| Operating netback | **38.26** | 45.33 | (16) | **49.80** | 39.86 | 25 |
| **Natural gas ($/mcf)** | | | | | | |
| Revenue | **2.78** | 1.45 | 92 | **2.00** | 2.05 | (2) |
| Royalties | **-** | (0.04) | (100) | **-** | (0.06) | (100) |
| Net operating expenses | **(0.78)** | (0.75) | 4 | **(0.82)** | (0.93) | (12) |
| Net transportation and marketing expenses | **(0.82)** | (0.51) | 61 | **(0.52)** | (0.65) | (20) |
| Operating netback | **1.18** | 0.15 | 687 | **0.66** | 0.41 | 61 |
| **Combined ($/boe)** | | | | | | |
| Revenue | **24.14** | 26.59 | (9) | **24.74** | 24.98 | (1) |
| Royalties | **0.16** | (2.75) | (106) | **(0.39)** | (2.17) | (82) |
| Net operating expenses | **(5.00)** | (5.13) | (3) | **(5.40)** | (6.12) | (12) |
| Net transportation and marketing expenses | **(3.92)** | (2.75) | 43 | **(2.69)** | (3.55) | (24) |
| Operating netback | **15.38** | 15.96 | (4) | **16.26** | 13.14 | 24 |

During the three months and year ended December 31, 2018, Leucrotta generated an operating netback of $15.38/boe and $16.26/boe, respectively, compared to $15.96/boe and $13.14/boe for the comparative periods in 2017. The large increase in operating netback for the year ended December 31, 2018 compared to 2017 was mainly due to lower net operating expenses and net transportation and marketing expenses per boe and royalty credits from BC's IRCP. While these factors existed for the fourth quarter of 2018 compared to the fourth quarter of 2017, the operating netback slightly decreased as a result of very low oil and NGLs pricing and increased transportation partially offsetting the increase in natural gas pricing.

The following is a reconciliation of operating netback per boe to loss per boe for the periods noted:

| | Three Months Ended December 31 | | | Year Ended December 31 | | |
|---|---|---|---|---|---|---|
| ($/boe) | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| **Operating netback** | **15.38** | 15.96 | (4) | **16.26** | 13.14 | 24 |
| Depletion and depreciation | **(9.29)** | (9.21) | 1 | **(9.38)** | (9.77) | (4) |
| Exploration and evaluation | **-** | (17.84) | (100) | **-** | (5.97) | (100) |
| General and administrative expenses | **(5.48)** | (3.45) | 59 | **(4.05)** | (4.32) | (6) |
| Share based compensation | **(0.84)** | (1.05) | (20) | **(2.81)** | (1.49) | 89 |
| Finance expense | **(0.42)** | (0.32) | 31 | **(0.26)** | (0.27) | (4) |
| Finance income | **0.10** | 0.42 | (76) | **0.21** | 0.48 | (56) |
| Loss on sale of assets | **-** | (1.40) | (100) | **-** | (0.47) | (100) |
| Deferred income tax recovery | **-** | 2.38 | (100) | **-** | 0.80 | (100) |
| **Net loss** | **(0.55)** | (14.51) | (96) | **(0.03)** | (7.87) | (100) |

| DEPLETION AND DEPRECIATION | Three Months Ended December 31 | | | Year Ended December 31 | | |
|---|---|---|---|---|---|---|
| | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| Depletion and depreciation ($000s) | **2,736** | 3,222 | (15) | **12,147** | 10,212 | 19 |
| Depletion and depreciation ($/boe) | **9.29** | 9.21 | 1 | **9.38** | 9.77 | (4) |

The Company calculates depletion on property, plant, and equipment mainly based on proved plus probable reserves. Some facilities in Stoddart and certain gas plant equipment, where the production and reserves do not represent the useful life of the assets, are depreciated over twenty years. Depletion and depreciation for the three months and year ended December 31, 2018 was $9.29/boe and $9.38/boe, respectively, consistent with $9.21/boe and $9.77/boe for the comparative periods in 2017.

**IMPAIRMENT OF ASSETS AND EXPLORATION AND EVALUATION EXPENSE**

At December 31, 2018, the Company evaluated its property, plant, and equipment ("PP&E") CGUs for indicators of impairment or impairment reversals. During the year ended December 31, 2018, there were indicators of impairment identified in the Company's Montney CGU as a result of significant and sustained declines in the forward commodity prices for natural gas. An impairment test was performed based on value in use using commodity price estimates of the Company's independent reserve evaluators. The impairment tests at December 31, 2018 were primarily based on the net present value of cash flows from oil and natural gas reserves at pre-tax discount rates ranging from 10 to 20 percent depending on the underlying composition and risk profile of the reserve category. The Company has determined that there was no impairment to its Montney CGU at December 31, 2018.

At December 31, 2017, the Company evaluated its PP&E CGUs for indicators of impairment or impairment reversals and as a result of this assessment management determined that an impairment test was not required to be performed.

At December 31, 2018, the Company evaluated its Exploration and Evaluation ("E&E") assets for indicators of impairment or impairment reversals and as a result of this assessment management determined that an impairment test was not required to be performed.

During the year ended December 31, 2017, the Company recognized an expense of $6.2 million comprised of drilling and completion costs incurred for an exploratory well in the non-Montney CGU that was uneconomic and had no further expenditures planned.

| GENERAL AND ADMINISTRATIVE | Three Months Ended December 31 | | | Year Ended December 31 | | |
|---|---|---|---|---|---|---|
| ($000s) | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| G&A expenses (gross) | **1,813** | 1,411 | 28 | **5,834** | 5,227 | 12 |
| G&A capitalized | **(198)** | (203) | (2) | **(588)** | (775) | (24) |
| G&A recoveries | **(1)** | (1) | - | **(3)** | 68 | (104) |
| G&A expenses (net) | **1,614** | 1,207 | 34 | **5,243** | 4,520 | 16 |
| G&A expenses ($/boe) | **5.48** | 3.45 | 59 | **4.05** | 4.32 | (6) |

General and administrative ("G&A") expenses were $5.48/boe and $4.05/boe for the three months and year ended December 31, 2018, respectively, compared to $3.45/boe and $4.32/boe for the comparative periods in 2017. G&A expenses in the three months and year ended December 31, 2018 increased from 2017 mainly due to increased employment costs. On a per boe basis, G&A expenses decreased slightly for the year ended December 31, 2018 from 2017 due to the increased production during 2018. The opposite was the case when comparing the fourth quarter of 2018 to the fourth quarter of 2017 as flush production from Q4 2017 declined resulting in Q4 2018 production being lower than Q4 2017, thus increasing G&A on a per boe basis in Q4 2018.

| SHARE BASED COMPENSATION | Three Months Ended December 31 | | | Year Ended December 31 | | |
|---|---|---|---|---|---|---|
| | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| Share based compensation ($000s) | **247** | 367 | (33) | **3,645** | 1,554 | 135 |
| Share based compensation ($/boe) | **0.84** | 1.05 | (20) | **2.81** | 1.49 | 89 |

The Company accounts for its share based compensation plans using the fair value method. Under this method, compensation cost is charged to earnings over the vesting period for stock options and warrants granted to officers, directors, employees, and consultants with a corresponding increase to contributed surplus.

Share based compensation expense was $0.2 million and $3.6 million for the three months and year ended December 31, 2018, respectively, compared to $0.4 million and $1.6 million for the comparative periods in 2017. In May 2018, the expiry term for previously granted stock options, performance warrants and purchase warrants was extended to 6 years from the original term of 4 or 5 years. The incremental fair value of the modifications was $3.8 million and $3.5 million was recognized during the year ended December 31, 2018 based on the percentage of modified awards that were vested with the remaining expense to be recognized ratably as the awards vest. The incremental fair value was estimated immediately before and as at the date of modification using a Black-Scholes-Merton option pricing model.

| **FINANCE EXPENSE** | **Three Months Ended December 31** | | | **Year Ended December 31** | | |
|---|---|---|---|---|---|---|
| ($000s) | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| Interest expense | **69** | 61 | 13 | **141** | 125 | 13 |
| Accretion of decommissioning obligations | **53** | 49 | 8 | **200** | 162 | 23 |
| Finance expense | **122** | 110 | 11 | **341** | 287 | 19 |
| Finance expense ($/boe) | **0.42** | 0.32 | 31 | **0.26** | 0.27 | (4) |

Interest expense and accretion expense during the three months and year ended December 31, 2018 remained consistent with the comparable periods of 2017.

**FINANCE INCOME**

For the three months and year ended December 31, 2018, finance income totaled $28 thousand and $0.3 million, respectively, compared to $0.1 million and $0.5 million for the comparative periods in 2017. Finance income relates to interest earned on cash in the bank. The slight decrease in 2018 results from a lower bank balance in 2018 compared to 2017.

**DEFERRED INCOME TAXES**

The Company has not realized the net deferred income tax asset based on the independently evaluated reserve report as cash flows are not expected to be sufficient to realize the deferred income tax asset at this time.

The deferred income tax recovery of $0.8 million for the three months and year ended December 31, 2017 relates to the premium on the flow-through shares issued as the Company had incurred the entire amount with respect to qualifying Canadian exploration expenditures.

Estimated tax pools at December 31, 2018 total approximately $325.3 million (December 31, 2017 - $304.4 million).

**CASH FLOW FROM OPERATIONS AND ADJUSTED FUNDS FLOW**

The following is a reconciliation of cash flow from operating activities to adjusted funds flow for the periods noted:

| | **Three Months Ended December 31** | | | **Year Ended December 31** | | |
|---|---|---|---|---|---|---|
| ($000s) | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| Cash flow from operating activities | **3,764** | 3,294 | 14 | **16,249** | 8,311 | 96 |
| Add (deduct): | | | | | | |
| Decommissioning expenditures | **-** | 296 | (100) | **176** | 296 | (41) |
| Change in non-cash working capital | **(889)** | 872 | (202) | **(476)** | 995 | (148) |
| Adjusted funds flow (non-GAAP) | **2,875** | 4,462 | (36) | **15,949** | 9,602 | 66 |

Adjusted funds flow was $2.9 million ($0.01 per basic and diluted share) and $15.9 million ($0.08 per basic and diluted share) for the three months and year ended December 31, 2018, respectively, compared to $4.5 million ($0.02 per basic and diluted share) and $9.6 million ($0.05 per basic and diluted share) for the comparative periods in 2017. The increase for the year ended December 31, 2018 over 2017 was mainly the result of production growth from successful drilling at Doe/Mica, lower net operating and net transportation and marketing expenses, and royalty credits from BC's IRCP. The decrease for the fourth quarter of 2018 compared to the fourth quarter of 2017 was mainly the result of lower production and lower oil and NGLs pricing which was partially offset by higher natural gas pricing with increased net transportation and marketing expenses to transport the natural gas to Chicago.

Cash flow from operations increased for the three months and year ended December 31, 2018 to $3.8 million ($0.02 per basic and diluted share) and $16.2 million ($0.08 per basic and diluted share), respectively, from $3.3 million ($0.02 per basic and diluted share) and $8.3 million ($0.04 per basic and diluted share) for the comparative periods in 2017. Cash flow from operating activities differs from adjusted funds flow due to the inclusion of changes in non-cash working capital and decommissioning expenditures.

**NET LOSS**

Net loss for the three months ended December 31, 2018 was $0.2 million ($nil per basic and diluted share) compared to $5.1 million ($0.03 per basic and diluted share) for the comparative period in 2017. For the year ended December 31, 2018, the Company had a net loss of $43 thousand ($nil per basic and diluted share) compared to $8.2 million ($0.04 per basic and diluted share) for the comparative period in 2017. The decrease in the net loss in 2018 compared to 2017 was largely the result of a $6.2 million expense on non-core E&E assets in Q4 2017, in addition to cash flow items previously discussed.

| **CAPITAL EXPENDITURES** | **Three Months Ended December 31** | | | **Year Ended December 31** | | |
|---|---|---|---|---|---|---|
| ($000s) | **2018** | 2017 | % Change | **2018** | 2017 | % Change |
| Property acquisitions (net) | **-** | - | - | **-** | 35,550 | (100) |
| Land | **1,364** | 295 | 362 | **2,642** | 1,812 | 46 |
| Drilling, completions, and workovers | **7,744** | 11,646 | (34) | **26,736** | 34,831 | (23) |
| Equipment | **1,510** | 3,843 | (61) | **6,806** | 20,438 | (67) |
| Geological and geophysical | **47** | 86 | (45) | **434** | 883 | (51) |
| Office equipment | **-** | - | - | **62** | - | 100 |
| Total expenditures | **10,665** | 15,870 | (33) | **36,680** | 93,514 | (61) |

During the year ended December 31, 2018, the Company drilled and completed three Lower Montney delineation wells and one Upper Montney delineation well. One well was drilled in Alberta and three wells were drilled at Mica, BC (one drilled north of the Peace River). The Company also tied-in its Mica 12-06 and Mica 1-24 light oil Montney wells which commenced production during the year.

During the year ended December 31, 2017, the Company completed its Mica 12-06 well and drilled and completed Mica A8-22, Mica 9-33 and Doe 4-12. The Company also completed its infrastructure project to tie-in five previously drilled wells in Doe/Mica (8-18, 8-22, 8-4, A13-19, and A4-19) and drilled an exploratory well at Stoddart and at Two Rivers, north of the Peace River. The Company also had net property acquisitions of $35.6 million in Q2 2017. Net assets acquired were undeveloped land in the Company's core Doe/Mica area, adding to the land inventory of this area with a focus on the Montney formation. There were no reserves attached to any of the net acquisition lands.

## LIQUIDITY AND CAPITAL RESOURCES

Management uses working capital as a measure to assess the Company's financial position and is reconciled as follows:

| ($000s) | **December 31, 2018** | December 31, 2017 | % Change |
|---|---|---|---|
| Current assets | **11,131** | 29,224 | (62) |
| Less: | | | |
| Current liabilities | **(9,029)** | (10,564) | (15) |
| Working capital | **2,102** | 18,660 | (89) |

At December 31, 2018, the Company had working capital of $2.1 million inclusive of $2.4 million drawn on the revolving credit facility. Included in working capital at December 31, 2018 was $4.3 million of equipment held for sale which related to the sale of certain gas plant equipment that closed subsequent to December 31, 2018.

The Company has a $20.0 million revolving operating demand loan credit facility with a Canadian chartered bank. The revolving credit facility bears interest at prime plus a range of 0.50% to 2.50% and is secured by a $100 million fixed and floating charge debenture on the assets of the Company. The undrawn portion of the credit facility is subject to a standby fee in the range of 0.20% to 0.45%. At December 31, 2018, the Company had outstanding letters of guarantee of $3.6 million which reduce the amount that can be borrowed under the credit facility.

At December 31, 2018, the Company has $1.0 million (December 31, 2017 - $1.0 million) in a restricted corporate account to cross-guarantee a margin account for the President of the Company. The President is charged a fee by the Company and the margin account is also restricted until the cross-guarantee is removed. The margin account holds $3.4 million of securities of Leucrotta common shares and a margin payable of $1.0 million. The cross-guarantee is intended to be temporary in nature and will be removed as soon as practicable. The cross-guarantee has allowed the President to comply with corporate governance mandates. The $1.0 million has been segregated on the statement of financial position as restricted cash at December 31, 2018.

Management anticipates that the Company will continue to have adequate liquidity to fund budgeted capital investments through a combination of its cash balance, cash flow, equity, and debt if required. Leucrotta's capital program is flexible and can be adjusted as needed based upon the current economic environment. The Company will continue to monitor the economic environment and the possible impact on its business and strategy and will make adjustments as necessary.

## CONTRACTUAL OBLIGATIONS

The following is a summary of the Company's contractual obligations and commitments at December 31, 2018:

| ($000s) | **Total** | **Less than One Year** | **One to Three Years** | **After Three Years** |
|---|---|---|---|---|
| Accounts payable and accrued liabilities | 6,673 | 6,673 | - | - |
| Revolving credit facility | 2,356 | 2,356 | - | - |
| Decommissioning obligations | 9,572 | - | - | 9,572 |
| Office leases | 907 | 320 | 587 | - |
| Equipment leases | 122 | 122 | - | - |
| Firm transportation agreements | 12,201 | 5,909 | 6,292 | - |
| Total contractual obligations | 31,831 | 15,380 | 6,879 | 9,572 |

Transportation commitments include contracts to transport natural gas and NGLs through third-party owned pipeline systems. The Company currently has commitments of 16 mmcf/d escalating to 33.3 mmcf/d in November 2019.

**OFF BALANCE SHEET ARRANGEMENTS**

The Company has certain lease arrangements, all of which are reflected in the contractual obligations and commitments table, which were entered into in the normal course of operations. All leases have been treated as operating leases whereby the lease payments are included in operating expenses or general and administrative expenses depending on the nature of the lease.

**OUTSTANDING SHARE DATA**

The Company is authorized to issue an unlimited number of voting common shares, an unlimited number of non-voting common shares, Class A preferred shares, issuable in series, and Class B preferred shares, issuable in series. The voting common shares of the Company commenced trading on the TSXV on August 19, 2014 under the symbol "LXE". The following table summarizes the common shares outstanding and the number of shares exercisable into common shares from options, warrants, and other instruments:

| (000s) | **December 31, 2018** | April 22, 2019 |
|---|---|---|
| Voting common shares | **200,525** | 200,525 |
| Warrants | **15,135** | 15,135 |
| Stock options | **11,422** | 11,422 |
| Total | **227,082** | 227,082 |

**SUMMARY OF QUARTERLY RESULTS**

| | **Q4 2018** | Q3 2018 | Q2 2018 | Q1 2018 | Q4 2017 | Q3 2017 | Q2 2017 | Q1 2017 |
|---|---|---|---|---|---|---|---|---|
| Average Daily Production | | | | | | | | |
| Oil and NGLs (bbls/d) | **850** | 888 | 938 | 1,144 | 1,290 | 857 | 609 | 514 |
| Natural gas (mcf/d) | **14,115** | 14,724 | 15,297 | 18,216 | 15,071 | 13,593 | 12,122 | 8,197 |
| Combined (boe/d) | **3,202** | 3,342 | 3,487 | 4,180 | 3,802 | 3,123 | 2,629 | 1,881 |
| ($000s, except per share amounts) | | | | | | | | |
| Oil and natural gas sales | **7,113** | 7,182 | 7,327 | 10,426 | 9,301 | 5,723 | 6,317 | 4,783 |
| Cash flow from operating activities | **3,764** | 1,975 | 4,579 | 5,931 | 3,294 | 1,322 | 3,384 | 311 |
| Per share - basic and diluted | **0.02** | 0.01 | 0.02 | 0.03 | 0.02 | 0.01 | 0.02 | - |
| Adjusted funds flow | **2,875** | 3,339 | 3,348 | 6,387 | 4,462 | 1,747 | 2,097 | 1,296 |
| Per share - basic and diluted | **0.01** | 0.02 | 0.02 | 0.03 | 0.02 | 0.01 | 0.01 | 0.01 |
| Net earnings (loss) | **(161)** | (148) | (2,280) | 2,546 | (5,072) | (1,549) | (723) | (878) |
| Per share - basic and diluted | **(-)** | (-) | (0.01) | 0.01 | (0.03) | (0.01) | (-) | (0.01) |

Production, oil and natural gas sales, cash flow from operating activities and adjusted funds flow increased significantly in each quarter of 2017 and Q1 2018 from the successful drilling at Doe/Mica in the Montney formation. Natural declines on flush production from new wells lowered Q2 to Q4 2018 production. The increased loss in Q4 2017 from Q3 2017 was the result of a $6.2 million expense related to non-core exploration and evaluation assets. The increased loss in Q2 2018 from Q1 2018 was the result of non-cash share based compensation expense related to the expiry term extension of existing stock options, performance warrants and purchase warrants.

**CHANGES IN ACCOUNTING POLICIES AND NEW STANDARDS AND INTERPRETATIONS NOT YET ADOPTED**

**IFRS 9, Financial Instruments**

Effective January 1, 2018, the Company adopted IFRS 9, "Financial Instruments" ("IFRS 9") which replaced IAS 39, "Financial Instruments: Recognition and Measurement" ("IAS 39"). The Company applied the new standard retrospectively and, in accordance with the transitional provisions, comparative figures have not been restated. The adoption of IFRS 9 did not have a material impact on the Company's financial statements.

IFRS 9 contains three principal classification categories for financial assets: measured at amortized cost; fair value through other comprehensive income ("FVOCI") and fair value through profit or loss ("FVTPL"). The classification of financial assets under IFRS 9 is generally based on the contractual cash flow characteristics and the Company's business model for managing the financial asset. The previous IAS 39 categories of held to maturity, loans and receivables and available for sale have been eliminated. Additionally, embedded derivatives are not separated if the host contract is a financial asset within the scope of IFRS 9. Instead, the entire hybrid contract is assessed for classification and measurement. IFRS 9 largely retains the existing requirements in IAS 39 for the classification of financial liabilities.

The following table shows the original measurement categories under IAS 39 and the new measurement categories under IFRS 9 as at January 1, 2018 for each class of the Company's financial assets and financial liabilities:

| | Measurement category | |
|---|---|---|
| **Financial instrument** | **IAS 39** | **IFRS 9** |
| Cash and cash equivalents | Loans and receivables | Amortized cost |
| Restricted cash | Loans and receivables | Amortized cost |
| Accounts receivable | Loans and receivables | Amortized cost |
| Accounts payable and accrued liabilities | Financial liabilities at amortized cost | Amortized cost |
| Borrowings under credit facility | Financial liabilities at amortized cost | Amortized cost |

There were no adjustments to the carrying amounts of the Company's financial instruments as a result of the change in classification from IAS 39 to IFRS 9. The Company has not designated any financial instruments as FVOCI or FVTPL, nor does the Company use hedge accounting.

IFRS 9 replaces the 'incurred loss' model in IAS 39 with an 'expected credit loss' ("ECL") model. The new impairment model applies to financial assets measured at amortized cost, contract assets and debt investments measured at FVOCI. The Company measures loss allowances at an amount equal to expected lifetime ECLs. Lifetime ECLs are the anticipated ECLs that result from all possible default events over the life of a financial asset. ECLs are a probability-weighted estimate of credit loss and are discounted at the effective interest rate of the related financial asset. The application of the new expected credit loss model did not have a significant impact on the Company's financial assets or result in any additional provision for impairment.

**IFRS 15, Revenue from Contracts with Customers**

The Company adopted IFRS 15, "Revenue from Contracts with Customers" ("IFRS 15") effective January 1, 2018. IFRS 15 replaces IAS 18, "Revenue", IAS 11, "Construction Contracts", and several revenue-related interpretations.

The Company applied IFRS 15 to all of its contracts with customers using the modified retrospective method. Management reviewed the Company's revenue streams and major contracts with customers using the IFRS 15 principles-based five-step model and concluded that there were no material changes to earnings or timing of when production revenue is recognized. However, it was determined that certain transactions in respect of third party marketing arrangements that optimized the Company's transportation capacity were previously presented net within transportation expenses have been reclassified and presented separately in the financial statements for comparability with the current period presentation for those items, being the purchase and subsequent sale of natural gas. Also the accounting for certain processing charges incurred after control of the product transferred resulted in decreases to both oil and natural gas sales and operating expenses. There was no resultant impact on earnings, cash flow or financial position of the Company from these changes, but does result in additional disclosure requirements.

The Company earns revenue from its production and sale of oil, natural gas and natural gas liquids ("NGLs") and from fees charged to third parties for processing and other services provided at facilities where the Company has an ownership interest.

Revenue from the sale of oil, natural gas and NGLs is recognized based on the consideration specified in contracts with customers. The Company recognizes revenue when control of the product transfers to the customer and collection is reasonable assured. This is generally at the point in time when the customer obtains legal title to the product which is when it is physically transferred to the pipeline or other transportation method agreed upon. Revenues from processing activities are recognized over time as processing occurs, and are generally billed monthly.

The Company evaluates its arrangements with third parties and partners to determine if the Company is acting as the principal or as an agent. In making this evaluation, management considers if the Company obtains control of the product delivered, which is indicated by the Company having the primary responsibility for the delivery of the product, having the ability to establish prices or having inventory risk. If the Company acts in the capacity of an agent rather than as a principal in a transaction, then revenue is recognized on a net basis, only reflecting the fee, if any, realized by the Company from the transaction.

Tariffs, tolls and fees charged to other entities for use of pipelines and facilities owned by the Company are evaluated by management to determine if these originate from contracts with customers or from incidental or collaborative arrangements. Tariffs, tolls and fees charged to other entities that are from contracts with customers are recognized in revenue when the related services are provided.

When allocating the transaction price realized in contracts with multiple performance obligations, management is required to make estimates of the prices at which the Company would sell the product separately to customers.

**IFRS 16, Leases**

On January 13, 2016, the IASB issued IFRS 16, "Leases" ("IFRS 16"). The new standard is effective for annual periods beginning on or after January 1, 2019. IFRS 16 will replace IAS 17, "Leases". This standard introduces a single lessee accounting model and requires a lessee to recognize assets and liabilities for all leases with a term of more than 12 months, unless the underlying asset is of low value. A lessee is required to recognize a right-of-use asset representing its right to use the underlying asset and a lease liability representing its obligation to make lease payments. The new standard is to be adopted either retrospectively or using a modified retrospective approach. IFRS 16 will be applied by Leucrotta on January 1, 2019 using the modified retrospective transition approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect of IFRS 16 as an adjustment to the opening retained earnings (deficit) and applies the standard prospectively. The Company's contract assessment remains ongoing and it has not yet determined the full extent of the impact of adoption, however, the Company expects an adjustment and recognition of a right-of-use asset and corresponding lease liability for its office lease.

## CRITICAL ACCOUNTING ESTIMATES

Management is required to make estimates, judgments, and assumptions in the application of IFRS that affect the reported amounts of assets and liabilities at the date of the financial statements and revenues and expenses for the period then ended. Certain of these estimates may change from period to period resulting in a material impact on the Company's results from operations and financial position (see note 2d in the notes to the Company's financial statements for full descriptions of the use of estimates and judgments).

## RISK ASSESSMENT

The acquisition, exploration, and development of oil and natural gas properties involves many risks common to all participants in the oil and natural gas industry. Leucrotta's exploration and development activities are subject to various business risks such as unstable commodity prices, interest rate and foreign exchange fluctuations, the uncertainty of replacing production and reserves on an economic basis, government regulations, taxes, and safety and environmental concerns. While management realizes these risks cannot be eliminated, they are committed to monitoring and mitigating these risks.

### Reserves and reserve replacement

The recovery and reserve estimates on Leucrotta's properties are estimates only and the actual reserves may be materially different from that estimated. The estimates of reserve values are based on a number of variables including price forecasts, projected production volumes and future production and capital costs. All of these factors may cause estimates to vary from actual results.

Leucrotta's future oil and natural gas reserves, production, and adjusted funds flow to be derived therefrom are highly dependent on the Company successfully acquiring or discovering new reserves. Without the continual addition of new reserves, any existing reserves the Company may have at any particular time and the production therefrom will decline over time as such existing reserves are exploited. A future increase in Leucrotta's reserves will depend on its abilities to acquire suitable prospects or properties and discover new reserves.

To mitigate this risk, Leucrotta has assembled a team of experienced technical professionals who have expertise operating and exploring in areas the Company has identified as being the most prospective for increasing reserves on an economic basis. To further mitigate reserve replacement risk, Leucrotta has targeted a majority of its prospects in areas which have multi-zone potential, year-round access, and lower drilling costs and employs advanced geological and geophysical techniques to increase the likelihood of finding additional reserves.

### Operational risks

Leucrotta's operations are subject to the risks normally incidental to the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells. Continuing production from a property, and to some extent the marketing of production therefrom, are largely dependent upon the ability of the operator of the property.

#### *Market risk*

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk is comprised of foreign currency risk, interest rate risk, and other price risk, such as commodity price risk. The objective of market risk management is to manage and control market price exposures within acceptable limits, while maximizing returns. The Company may use financial derivatives or physical delivery sales contracts to manage market risks. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors. As required under the terms of the Company's credit facility, the Company is subject to an upper limit on fixed price contracts of 65% of its future production up to a three year period.

*Foreign exchange risk*
The prices received by the Company for the production of oil, natural gas, and NGLs are primarily determined in reference to US dollars, but are settled with the Company in Canadian dollars. The Company's cash flow from commodity sales will therefore be impacted by fluctuations in foreign exchange rates. The Company currently does not have any foreign exchange contracts in place.

*Interest rate risk*
The Company is exposed to interest rate risk when it borrows funds at floating interest rates. The Company currently does not use interest rate hedges or fixed interest rate contracts to manage the Company's exposure to interest rate fluctuations. The amount drawn on the Company's credit facility at December 31, 2018 was $2.4 million.

*Commodity price risk*
Oil and natural gas prices are impacted by not only the relationship between the Canadian and US dollar but also by world economic events that dictate the levels of supply and demand. The Company's oil, natural gas, and NGLs production is marketed and sold on the spot market to area aggregators based on daily spot prices that are adjusted for product quality and transportation costs. The Company's cash flow from product sales will therefore be impacted by fluctuations in commodity prices. In addition, the Company may enter into commodity price contracts to manage future cash flows. At December 31, 2018, the Company did not have any commodity price contracts outstanding.

#### *Credit risk*

Credit risk represents the financial loss that the Company would suffer if the Company's counterparties to a financial asset fail to meet or discharge their obligation to the Company. A substantial portion of the Company's accounts receivable and deposits are with customers and joint interest partners in the oil and natural gas industry and are subject to normal industry credit risks. The Company generally grants unsecured credit but routinely assesses the financial strength of its customers and joint interest partners.

The Company sells the majority of its production to three petroleum and natural gas marketers and therefore is subject to concentration risk. Historically, the Company has not experienced any collection issues with its oil and natural gas marketers. Joint interest receivables are typically collected within one to three months of the joint interest billing being issued to the partner. The Company attempts to mitigate the risk from joint interest receivables by obtaining partner approval for significant capital expenditures prior to the expenditure being incurred. The Company does not typically obtain collateral from petroleum and natural gas marketers or joint interest partners; however, in certain circumstances, the Company may cash call a partner in advance of expenditures being incurred.

The maximum exposure to credit risk is represented by the carrying amount of cash and cash equivalents, restricted cash, and accounts receivable on the statement of financial position. At December 31, 2018, $2.2 million (74%) of the Company's outstanding accounts receivable were current and $0.4 million (15%) were outstanding for more than 90 days. During the period ended December 31, 2018, the Company did not deem any outstanding accounts receivable to be uncollectable (December 31, 2017 - $0.1 million).

Cash and cash equivalents consists of bank balances placed with a financial institution with strong investment grade ratings which management believes the risk of loss to be remote.

***Liquidity risk***

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's processes for managing liquidity risk include ensuring, to the extent possible, that it will have sufficient liquidity to meet its liabilities when they become due. The Company prepares annual, quarterly, and monthly capital expenditure budgets, which are monitored and updated as required, and requires authorizations for expenditures on projects to assist with the management of capital. In managing liquidity risk, the Company ensures that it has access to additional financing, including potential equity issuances and additional debt financing. The Company also mitigates liquidity risk by maintaining an insurance program to minimize exposure to insurable losses.

The Company has a working capital balance of $2.1 million inclusive of $2.4 million drawn on the revolving credit facility. Management anticipates that the Company will continue to have adequate liquidity to fund budgeted capital investments through a combination of its cash balance, cash flow, equity, and debt if required.

**Safety and Environmental Risks**

The oil and natural gas business is subject to extensive regulation pursuant to various municipal, provincial, national, and international conventions and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases, or emissions of various substances produced in association with oil and natural gas operations. Leucrotta is committed to meeting and exceeding its environmental and safety responsibilities. Leucrotta has implemented an environmental and safety policy that is designed, at a minimum, to comply with current governmental regulations set for the oil and natural gas industry. Changes to governmental regulations are monitored to ensure compliance. Environmental reviews are completed as part of the due diligence process when evaluating acquisitions. Environmental and safety updates are presented and discussed at each Board of Directors meeting. Leucrotta maintains adequate insurance commensurate with industry standards to cover reasonable risks and potential liabilities associated with its activities as well as insurance coverage for officers and directors executing their corporate duties. To the knowledge of management, there are no legal proceedings to which Leucrotta is a party or of which any of its property is the subject matter, nor are any such proceedings known to Leucrotta to be contemplated.

**FORWARD-LOOKING INFORMATION**

This document 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 MD&A contains forward-looking statements and information relating to the Company's risk management program, oil, NGLs, and natural gas production, capital programs, and working capital. 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.

**ADDITIONAL INFORMATION**

Additional information related to the Company may be found on the SEDAR website at www.sedar.com.

**INDEPENDENT AUDITORS' REPORT**

To the Shareholders of Leucrotta Exploration Inc.

***Opinion***

We have audited the financial statements of Leucrotta Exploration Inc. (the "Company"), which comprise:

- the statements of financial position as at December 31, 2018 and December 31, 2017
- the statements of operations and comprehensive loss for the years then ended
- the statements of shareholders' equity for the years then ended
- the statements of cash flows for the years then ended
- and notes to the financial statements, including a summary of significant accounting policies

Hereinafter referred to as the "financial statements".

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2018 and December 31, 2017, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards ("IFRS").

***Basis for Opinion***

We conducted our audit in accordance with Canadian generally accepted auditing standards. Our responsibilities under those standards are further described in the "*Auditors' Responsibilities for the Audit of the Financial Statements*" section of our auditors' report.

We are independent of the Company in accordance with the ethical requirements that are relevant to our audit of the financial statements in Canada and we have fulfilled our other ethical responsibilities in accordance with these requirements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our opinion.

***Other Information***

Management is responsible for the other information. Other information comprises:

- the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions.
- the information, other than the financial statements and the auditors' report thereon, included the 2018 Annual Report.

Our opinion on the financial statements does not cover the other information and we do not and will not express any form of assurance conclusion thereon.

In connection with our audit of the financial statements, our responsibility is to read the other information identified above and, in doing so, consider whether the other information is materially inconsistent with the financial statements or our knowledge obtained in the audit and remain alert for indications that the other information appears to be materially misstated.

We obtained the information included in Management's Discussion and Analysis filed with the relevant Canadian Securities Commissions and the 2018 Annual Report as at the date of this auditors' report. If, based on the work we have performed on this other information, we conclude that there is a material misstatement of this other information, we are required to report that fact in the auditors' report.

We have nothing to report in this regard.

***Responsibilities of Management and Those Charged with Governance for the Financial Statements***

Management is responsible for the preparation and fair presentation of the financial statements in accordance with IFRS, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

In preparing the financial statements, management is responsible for assessing the Company's ability to continue as a going concern, disclosing as applicable, matters related to going concern and using the going concern basis of accounting unless management either intends to liquidate the Company or to cease operations, or has no realistic alternative but to do so.

Those charged with governance are responsible for overseeing the Company's financial reporting process.

***Auditors' Responsibilities for the Audit of the Financial Statements***

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditors' report that includes our opinion.

Reasonable assurance is a high level of assurance, but is not a guarantee that an audit conducted in accordance with Canadian generally accepted auditing standards will always detect a material misstatement when it exists.

Misstatements can arise from fraud or error and are considered material if, individually or in the aggregate, they could reasonably be expected to influence the economic decisions of users taken on the basis of the financial statements.

As part of an audit in accordance with Canadian generally accepted auditing standards, we exercise professional judgment and maintain professional skepticism throughout the audit.

We also:

- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, design and perform audit procedures responsive to those risks, and obtain audit evidence that is sufficient and appropriate to provide a basis for our opinion.

The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control.

- Obtain an understanding of internal control relevant to the audit in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control.
- Evaluate the appropriateness of accounting policies used and the reasonableness of accounting estimates and related disclosures made by management.
- Conclude on the appropriateness of management's use of the going concern basis of accounting and, based on the audit evidence obtained, whether a material uncertainty exists related to events or conditions that may cast significant doubt on the Company's ability to continue as a going concern. If we conclude that a material uncertainty exists, we are required to draw attention in our auditors' report to the related disclosures in the financial statements or, if such disclosures are inadequate, to modify our opinion. Our conclusions are based on the audit evidence obtained up to the date of our auditors' report. However, future events or conditions may cause the Company to cease to continue as a going concern.
- Evaluate the overall presentation, structure and content of the financial statements, including the disclosures, and whether the financial statements represent the underlying transactions and events in a manner that achieves fair presentation.
- Communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit and significant audit findings, including any significant deficiencies in internal control that we identify during our audit.
- Provide those charged with governance with a statement that we have complied with relevant ethical requirements regarding independence, and communicate with them all relationships and other matters that may reasonably be thought to bear on our independence, and where applicable, related safeguards.

The engagement partner on the audit resulting in this auditors' report is John Waiand.

KPMG LLP

Chartered Professional Accountants

Calgary, Canada

April 22, 2019

**Leucrotta Exploration Inc.**
**Statements of Financial Position**

| ($000s) | Note | **December 31 2018** | December 31 2017 |
|---|---|---|---|
| **Assets** | | | |
| Current assets | | | |
| Cash and cash equivalents | | **2,729** | 23,747 |
| Restricted cash | (4) | **1,000** | 1,000 |
| Accounts receivable | | **2,896** | 4,104 |
| Prepaid expenses and deposits | | **192** | 373 |
| Equipment held for sale | (5) | **4,314** | - |
| | | **11,131** | 29,224 |
| Property, plant, and equipment | (6) | **187,432** | 156,395 |
| Exploration and evaluation assets | (7) | **118,480** | 127,422 |
| | | **305,912** | 283,817 |
| | | **317,043** | 313,041 |
| **Liabilities** | | | |
| Current liabilities | | | |
| Accounts payable and accrued liabilities | | **6,673** | 10,564 |
| Revolving credit facility | (8) | **2,356** | - |
| | | **9,029** | 10,564 |
| Decommissioning obligations | (9) | **9,572** | 8,718 |
| | | **18,601** | 19,282 |
| **Shareholders' Equity** | | | |
| Shareholders' capital | (10) | **288,837** | 288,787 |
| Contributed surplus | | **19,074** | 14,398 |
| Deficit | | **(9,469)** | (9,426) |
| | | **298,442** | 293,759 |
| | | **317,043** | 313,041 |

| | |
|---|---|
| Commitments | (23) |
| Subsequent event | (5) |

*The accompanying notes are an integral part of these financial statements.*

Approved on behalf of the Board of Directors

**Rob Zakresky**
Director

**Tom Medvedic**
Director

**Leucrotta Exploration Inc.**
**Statements of Operations and Comprehensive Loss**

| | | Years Ended December 31 | |
|---|---|---|---|
| ($000s, except per share amounts) | **Note** | **2018** | 2017 |
| **Revenue** | | | |
| Oil and natural gas sales | (21) | **32,048** | 26,124 |
| Processing and marketing | (21) | **1,752** | 1,838 |
| Royalties | (21) | **(506)** | (2,267) |
| | | **33,294** | 25,695 |
| **Expenses** | | | |
| Operating | | **7,887** | 6,400 |
| Transportation and marketing | (22) | **4,350** | 5,553 |
| Depletion and depreciation | (6) | **12,147** | 10,212 |
| Exploration and evaluation | (7) | **-** | 6,240 |
| General and administrative | | **5,243** | 4,520 |
| Share based compensation | (11) | **3,645** | 1,554 |
| Loss on sale of assets | | **-** | 489 |
| Finance income | | **(276)** | (505) |
| Finance expense | (14) | **341** | 287 |
| | | **33,337** | 34,750 |
| Loss before taxes | | **(43)** | (9,055) |
| **Taxes** | | | |
| Deferred income tax recovery | (15) | **-** | 833 |
| Net loss and comprehensive loss | | **(43)** | (8,222) |
| Net loss per share | | | |
| Basic and diluted | (12) | **(-)** | (0.04) |

*The accompanying notes are an integral part of these financial statements.*

**Leucrotta Exploration Inc.**
**Statements of Shareholders' Equity**

| ($000s) | Shareholders' Capital | Contributed Surplus | Deficit | Total Equity |
|---|---|---|---|---|
| Balance, December 31, 2016 | 213,875 | 12,493 | (1,204) | 225,164 |
| Net loss | - | - | (8,222) | (8,222) |
| Issue of shares (net of share issue costs and flow-through share premium) | 74,774 | - | - | 74,774 |
| Exercise of warrants and stock options | 138 | (40) | - | 98 |
| Share based compensation | - | 1,945 | - | 1,945 |
| Balance, December 31, 2017 | 288,787 | 14,398 | (9,426) | 293,759 |
| | | | | |
| Balance, December 31, 2017 | 288,787 | 14,398 | (9,426) | 293,759 |
| Net loss | **-** | **-** | **(43)** | **(43)** |
| Exercise of stock options | **50** | **(15)** | **-** | **35** |
| Share based compensation | **-** | **4,691** | **-** | **4,691** |
| **Balance, December 31, 2018** | **288,837** | **19,074** | **(9,469)** | **298,442** |

*The accompanying notes are an integral part of these financial statements.*

**Leucrotta Exploration Inc.**
**Statements of Cash Flows**

| ($000s) | Note | Years Ended December 31 2018 | 2017 |
|---|---|---|---|
| **Operating Activities** | | | |
| Net loss | | **(43)** | (8,222) |
| Depletion and depreciation | (6) | **12,147** | 10,212 |
| Exploration and evaluation | (7) | **-** | 6,240 |
| Share based compensation | (11) | **3,645** | 1,554 |
| Finance expense | (14) | **341** | 287 |
| Interest paid | (14) | **(141)** | (125) |
| Loss on sale of assets | | **-** | 489 |
| Deferred income tax recovery | (15) | **-** | (833) |
| Decommissioning expenditures | (9) | **(176)** | (296) |
| Change in non-cash working capital | (20) | **476** | (995) |
| | | **16,249** | 8,311 |
| **Financing Activities** | | | |
| Revolving credit facility | (8) | **2,356** | - |
| Issue of shares | | **-** | 80,001 |
| Share issue costs | | **-** | (4,394) |
| Exercise of warrants and stock options | | **35** | 98 |
| | | **2,391** | 75,705 |
| **Investing Activities** | | | |
| Capital expenditures - property, plant, and equipment | (6) | **(9,284)** | (27,682) |
| Capital expenditures - exploration and evaluation assets | (7) | **(27,396)** | (30,282) |
| Property acquisitions | | **-** | (35,550) |
| Disposition of oil and natural gas properties and equipment | | **-** | 1,100 |
| Deposit on equipment held for sale | (5) | **2,729** | - |
| Change in non-cash working capital | (20) | **(5,707)** | (852) |
| | | **(39,658)** | (93,266) |
| Change in cash and cash equivalents | | **(21,018)** | (9,250) |
| Cash and cash equivalents, beginning of year | | **23,747** | 32,997 |
| Cash and cash equivalents, end of year | | **2,729** | 23,747 |

*The accompanying notes are an integral part of these financial statements.*

## 1. REPORTING ENTITY

Leucrotta Exploration Inc. ("Leucrotta" or the "Company") is an oil and natural gas company, actively engaged in the acquisition, development, exploration, and production of oil and natural gas reserves in northeastern British Columbia, Canada. Leucrotta was incorporated in Alberta, Canada under the Business Corporations Act (Alberta) on June 10, 2014 under the name of 1828073 Alberta Ltd., and subsequently changed its name to Leucrotta Exploration Inc. on July 15, 2014. The Company commenced trading on the TSX Venture Exchange ("TSXV") on August 19, 2014 under the symbol "LXE".

The Company conducts many of its activities jointly with others and these financial statements reflect only the Company's proportionate interest in such activities.

The Company's place of business is located at 700, 639 – 5$^{th}$ Avenue SW, Calgary, Alberta, Canada, T2P 0M9.

## 2. BASIS OF PRESENTATION

### (a) Statement of compliance

These financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB").

The financial statements were authorized for issuance by the Board of Directors on April 22, 2019.

### (b) Basis of measurement

The financial statements have been prepared on the historical cost basis.

### (c) Functional and presentation currency

The financial statements are presented in Canadian dollars, which is the functional currency of the Company.

### (d) Use of estimates and judgments

The preparation of financial statements in conformity with IFRS requires management to make estimates and use judgment regarding the reported amounts of assets and liabilities as at the date of the financial statements and the reported amounts of revenues and expenses during the period. By their nature, estimates are subject to measurement uncertainty and changes in such estimates in future periods could require a material change in the financial statements. Accordingly, actual results may differ from the estimated amounts as future confirming events occur.

Significant estimates and judgments made by management in the preparation of these financial statements are outlined below.

*Business combinations*
Business combinations are accounted for using the acquisition method. Under this method, the consideration transferred is allocated to the assets acquired and the liabilities assumed based on the fair values at the time of acquisition. In determining the fair value of the assets and liabilities, the Company is often required to make assumptions and estimates, such as reserves, future commodity prices, fair value of undeveloped land, discount rates, decommissioning obligations and possible outcome of any assumed contingencies.

*Cash-generating units ("CGU")*
The Company's assets are aggregated into CGUs for the purposes of calculating impairment. CGUs are determined based on the smallest group of assets that generate cash inflows independent of other assets or groups of assets. Determination of CGUs is subject to the Company's judgment and is based on geographical proximity, shared infrastructure, similar exposure to market risk, materiality, and the way in which management monitors the Company's operations. The Company reviews the composition of its CGUs at each reporting date to assess whether any changes are required in light of new facts and circumstances.

*Impairment*
Judgments are required to assess when impairment indicators exist and impairment testing is required. In determining the recoverable amount of assets, in the absence of quoted market prices, impairment tests are based on estimates of reserves, production rates, future oil and natural gas prices, future costs, discount rates, market value of land, and other relevant assumptions.

(i) Reserves – Assumptions that are valid at the time of reserve estimation may change significantly when new information becomes available. Changes in forward price estimates, operating costs, or recovery rates may change the economic status of reserves and may ultimately result in reserves being restated.
(ii) Oil and natural gas prices – Forward price estimates are used in the cash flow model. Commodity prices can fluctuate for a variety of reasons including supply and demand fundamentals, inventory levels, exchange rates, weather, and economic and geopolitical factors.

(iii) Discount rate – The discount rate used to calculate the net present value of cash flows is based on estimates of a discount rate specific to the risk of the CGU being assessed for impairment. Changes in the general economic environment could result in significant changes to this estimate.

*Exploration and evaluation assets*
The application of the Company's accounting policy for exploration and evaluation assets requires the Company to make certain judgments as to future events and circumstances as to whether economic quantities of reserves will be found so as to assess if technical feasibility and commercial viability has been achieved.

*Depletion and depreciation*
Amounts recorded for depletion and depreciation are based on estimates of total proved and probable oil and natural gas reserves and future development capital. By their nature, the estimates of reserves, including the estimates of future prices, costs, and future cash flows, are subject to measurement uncertainty. Accordingly, the impact to the financial statements in future periods could be material.

*Decommissioning obligations*
Amounts recorded for decommissioning obligations requires the use of estimates with respect to the amount and timing of decommissioning expenditures. Actual costs and cash outflows can differ from estimates because of changes in laws and regulations, public expectations, market conditions, discovery and analysis of site conditions and changes in technology. Other provisions are recognized in the period when it becomes probable that there will be a future cash outflow.

*Share based compensation*
Compensation costs recognized for share based compensation plans are subject to the estimation of what the ultimate value will be using pricing models such as the Black-Scholes-Merton model and Monte Carlo simulations, both of which are based on significant assumptions such as volatility, expected term, and forfeiture rate.

*Deferred taxes*
Deferred taxes are based on estimates as to the timing of the reversal of temporary differences, substantively enacted tax rates, and the likelihood of assets being realized. Tax interpretations, regulations, and legislation in the various jurisdictions in which the Company operates are subject to change. As such, income taxes are subject to measurement uncertainty. Judgments are also required to determine the likelihood of whether deferred income tax assets at the end of the reporting period will be realized from future taxable earnings.

## 3. SIGNIFICANT ACCOUNTING POLICIES

The accounting policies set out below have been applied consistently by the Company to all periods presented in these financial statements, other than as described below.

### (a) Joint arrangements

Joint arrangements represent activities where the Company has joint control established by a contractual agreement. Joint control requires unanimous consent for financial and operational decisions (being those that significantly affect the returns of the arrangement). A joint arrangement is either a joint operation, whereby the parties have rights to the assets and obligations for the liabilities, or a joint venture, whereby the parties have rights to the net assets. For a joint operation the financial statements include the Company's proportionate share of the assets, liabilities, revenues, expenses and cash flows of the arrangement with items of a similar nature on a line-by-line basis, from the date that joint control commences until the date that joint control ceases. Joint ventures are accounted for using the equity method of accounting and recognized at cost and adjusted thereafter for the post-acquisition change in the Company's share of the joint venture's net assets. Many of the Company's oil and natural gas activities involve joint operations. The Company has no arrangements classified as joint ventures.

### (b) Financial instruments

**Non-derivative financial instruments**

Financial instruments are recognized initially at fair value. Measurement in subsequent periods is dependent on the financial instrument's classification. The initial classification of a financial asset into one of the following three categories depends on the Company's business model for managing its financial assets and the contractual terms of the cash flows.

Amortized cost
Includes assets that are held within a business model whose objective is to hold assets to collect contractual cash flows and its contractual terms give rise on specified dates to cash flows that represent solely payments of principal and interest. Financial assets designated at amortized cost are initially recognized at fair value, net of directly attributable transaction costs, and are subsequently measured at amortized cost using the effective interest rate method, net of any impairment.

Fair value through other comprehensive income ("FVOCI")
Includes assets that are held within a business model whose objective is achieved by both collecting contractual cash flows and selling the financial assets, where its contractual terms give rise on specified dates to cash flows that represent solely payments of principal and interest. Financial assets designated at FVOCI are measured at fair value with changes in fair value recognized in other comprehensive income, net of tax.

Fair value through profit or loss ("FVTPL")

Includes assets that do not meet the criteria for amortized cost or FVOCI and are measured at fair value through profit or loss, including all derivative financial assets. Financial assets designated at FVTPL are initially recognized and subsequently measured at fair value with subsequent changes in fair value charged to earnings.

Financial liabilities are classified and measured at amortized cost or FVTPL. A financial liability is classified as FVTPL if it is held-for-trading, a derivative, or designated as FVTPL on initial recognition. The classification of a financial liability is irrevocable. Financial liabilities at FVTPL (other than financial liabilities designated at FVTPL) are measured at fair value with changes in fair value, along with any interest expense, recognized in earnings. Other financial liabilities are initially measured at fair value less attributable transaction costs and are subsequently measured at amortized cost using the effective interest method.

The Company derecognizes financial assets only when the contractual rights to cash flows from the financial assets expire, or when it transfers the financial assets and substantially all the associated risks and rewards of ownership to another entity. Gains and losses on derecognition are generally recognized in earnings. However, gains and losses on derecognition of financial assets classified as FVOCI remain within accumulated other comprehensive income.

A financial liability is derecognized when the obligation under the liability is discharged, cancelled or expires. When an existing financial liability is replaced by another from the same lender on substantially different terms, or the terms of an existing liability are substantially modified, such an exchange or modification is treated as a derecognition of the original liability and the recognition of a new liability, and the difference in the respective carrying amounts is recognized in earnings.

Financial assets and liabilities are offset and the net amount reported in the statement of financial position when there is a legally enforceable right to offset the recognized amounts, and there is an intention to settle on a net basis, or realize the asset and settle the liability simultaneously.

The Company's financial instruments comprise cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities, and credit facility, all of which are classified and measured at amortized cost.

**Derivative financial instruments**

From time to time, the Company may enter into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices. These instruments are not used for trading or speculative purposes. The Company does not designate financial derivative contracts as effective accounting hedges, and thus does not apply hedge accounting, even though the Company considers all commodity contracts to be economic hedges. As a result, all financial derivative contracts are classified as fair value through profit or loss and are measured at fair value, with changes therein recognized in profit or loss. Transaction costs are recognized in profit or loss when incurred.

Embedded derivatives are separated from the host contract and accounted for separately if the economic characteristics and risks of the host contract and the embedded derivative are not closely related, a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative, and the combined instrument is not measured at fair value through profit or loss. Changes in the fair value of separable embedded derivatives are recognized immediately in earnings. Derivatives embedded in hybrid contracts that contain financial asset hosts within the scope of IFRS 9 are not separated and the entire contract is measured at either FVTPL or amortized cost, as appropriate.

**Share capital**

Common shares are classified as equity. Incremental costs directly attributable to the issue of common shares are recognized as a deduction from equity, net of any tax effects.

**(c) Property, plant, and equipment and exploration and evaluation assets**

**Recognition and measurement**

*Exploration and evaluation expenditures*
Pre-license costs are recognized in profit or loss as incurred.

Exploration and evaluation costs, including the costs of acquiring undeveloped land and drilling costs, are initially capitalized until the drilling of the well is complete and the results have been evaluated. The costs are accumulated in cost centers by well, field, or exploration area pending determination of technical feasibility and commercial viability. The technical feasibility and commercial viability of extracting a mineral resource is considered to be determinable when proved or probable reserves are determined to exist. If proved or probable reserves are found, the accumulated costs and associated undeveloped land are transferred to property, plant, and equipment. The exploration and evaluation costs are reviewed for impairment prior to any such transfer.

Exploration and evaluation assets are assessed for impairment if (i) sufficient data exists to determine technical feasibility and commercial viability, and are transferred to property, plant, and equipment, and (ii) facts and circumstances suggest that the carrying amount exceeds the recoverable amount. For purposes of impairment testing, exploration and evaluation assets are allocated to their respective CGUs.

*Development and production costs*
Items of property, plant, and equipment, which include oil and natural gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. The cost of development and production assets includes: transfers from exploration and evaluation assets, which generally include the cost to drill the well and the cost of the associated land upon determination of technical feasibility and commercial viability; the cost to complete

and tie-in the well; facility costs; the cost of recognizing provisions for future restoration and decommissioning obligations; geological and geophysical costs; and directly attributable overhead.

Development and production assets are grouped into CGUs for impairment testing. The Company currently has two CGUs both being located in Northeast BC, one being the Company's Montney assets and the other being its non-Montney assets.

When significant parts of an item of property, plant, and equipment, including oil and natural gas interests, have different useful lives, they are accounted for as separate items (major components).

Gains and losses on disposal of an item of property, plant, and equipment, including oil and natural gas interests, are determined by comparing the proceeds from disposal with the carrying amount of property, plant, and equipment and are recognized in profit or loss. The carrying amount of any replaced or disposed item of property, plant, and equipment is derecognized.

**Subsequent costs**

Costs incurred subsequent to the determination of technical feasibility and commercial viability and the costs of replacing parts of property, plant, and equipment are recognized as property, plant, and equipment only when they increase the future economic benefits embodied in the specific asset to which they relate. Capitalized property, plant, and equipment generally represent costs incurred in developing proved or probable reserves and bringing in or enhancing production from such reserves and are accumulated on a field or geotechnical area basis. The costs of the day-to-day servicing of property, plant, and equipment are recognized in operating expenses as incurred.

**Non-monetary asset swaps**

Exchanges or swaps of property, plant, and equipment are measured at fair value unless the exchange transaction lacks commercial substance or neither the fair value of the assets given up nor the assets received can be reliably estimated. The cost of the acquired asset is measured at the fair value of the asset given up, unless the fair value of the asset received is more clearly evident. Where fair value is not used, the cost of the acquired asset is measured at the carrying amount of the asset given up. Any gain or loss on derecognition of the asset given up is included in profit or loss. Exchanges or parts of exchanges that involve principally exploration and evaluation assets are measured at the carrying amount of the asset exchanged, reduced by the amount of any cash consideration received. No gain or loss is recognized unless the cash consideration received exceeds the carrying value of the asset held.

**Depletion and depreciation**

The net carrying value of development and production assets is depleted using the unit of production method by reference to the ratio of production in the period to the related proved plus probable reserves, taking into account the estimated future development costs necessary to bring those reserves into production and the estimated salvage value of the assets at the end of their useful lives. Future development costs are estimated taking into account the level of development required to produce the reserves.

Proved plus probable reserves are estimated at least annually by independent qualified reserve evaluators and represent the estimated quantities of oil, natural gas, and natural gas liquids which geological, geophysical, and engineering data demonstrate with a specified degree of certainty to be recoverable in future years from known reservoirs and which are considered commercially producible.

The Company has determined the estimated useful lives for most gas processing plants, pipeline facilities, and compression facilities to be consistent with the reserve lives of the areas for which they serve. As such, the Company includes the cost of these assets within their associated CGU for the purpose of depletion using the unit of production method. Some facilities, where the production and reserves do not represent the useful life of the assets, are depreciated over an estimated useful life of twenty years.

The cost of office and other equipment is depreciated using the straight-line method over the estimated useful life of three years.

Depreciation methods, useful lives, and residual values are reviewed at each reporting date and, if necessary, changes are accounted for prospectively.

**Leased assets**

Leases wherein the Company assumes substantially all the risks and rewards of ownership are classified as finance leases, when applicable. Upon initial recognition, the leased asset is measured at an amount equal to the lower of its fair value and the present value of the minimum lease payments. Subsequent to initial recognition, the asset is accounted for in accordance with the accounting policy applicable to that asset. Minimum lease payments made under finance leases are apportioned between the finance expenses and the reduction of the outstanding liability. The finance expenses are allocated to each year during the lease term so as to produce a constant periodic rate of interest on the remaining balance of the liability. Other leases are classified as operating leases, which are not recognized on the Company's statement of financial position. Payments made under operating leases are recognized in profit or loss on a straight-line basis over the term of the lease. The Company's presently outstanding leases (primarily the head office lease) have been determined to be operating leases.

### Assets held for sale

Non-current assets, or disposal groups consisting of assets and liabilities, are classified as held for sale if their carrying amount will be recovered primarily through a sale transaction rather than through continuing use. Assets and liabilities qualifying as held for sale must be available for immediate sale in their present condition, subject only to terms that are usual and customary for sales of such assets, and their sale must be highly probable. Management must be committed to the sale, which should be expected to qualify for recognition as a completed sale within one year from the date of classification as held for sale.

Non-current assets, or disposal groups, are measured at the lower of their carrying amount and fair value less costs of disposal, with gains or losses recognized in income or loss. Non-current assets or disposal groups held for sale are presented in current assets and liabilities within the statement of financial position. Assets held for sale are not subject to depletion and depreciation.

## (d) Impairment

### Financial assets

The Company has elected to measure loss allowances for its financial assets measured at amortized cost at an amount equal to lifetime expected credit losses ("ECLs") as its accounts receivable are due within a period of less than one year and are not considered to have a significant financing component. The maximum period considered when estimating ECLs is the maximum contractual period over which the Company is exposed to credit risk. ECLs are a probability-weighted estimate of credit losses. Credit losses are measured as the present value of all cash shortfalls (i.e., the difference between the cash flows due to the Company in accordance with the contract and the cash flows that the Company expects to receive). ECLs are discounted at the effective interest rate of the financial asset.

### Non-financial assets

The carrying amounts of the Company's non-financial assets, other than exploration and evaluation assets and deferred tax assets, are reviewed at each reporting date to determine whether there is any indication of impairment. If any such indication exists, then the asset's recoverable amount is estimated. Exploration and evaluation assets are assessed for impairment when they are transferred to property, plant, and equipment or if facts and circumstances suggest that the carrying amount exceeds the recoverable amount.

For the purpose of impairment testing, assets are grouped together into the smallest group of assets that generate cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets (a cash-generating unit or "CGU"). The recoverable amount of an asset or a CGU is the greater of its value in use and its fair value less costs of disposal.

Fair value less costs of disposal is determined to be the amount for which the asset could be sold in an arm's length transaction. In determining fair value less costs of disposal, discounted cash flows and recent market transactions are taken into account. These calculations are corroborated by valuation multiples or other available fair value indicators.

Value in use is determined as the net present value of the estimated future cash flows expected to arise from the continued use of the asset in its present form and its eventual disposal. Value in use is determined by applying assumptions specific to the Company's continued use and can only take into account approved future development costs. Estimates of future cash flows used in the evaluation of impairment of assets are made using management's forecasts of commodity prices and expected production volumes. The latter takes into account assessments of field reservoir performance and includes expectations about proved and unproved volumes, which are risk-weighted using geological, production, recovery, and economic projections.

An impairment loss is recognized if the carrying amount of a CGU exceeds its estimated recoverable amount. Impairment losses are recognized in profit or loss. Impairment losses recognized in respect of CGUs are allocated to the assets in the CGUs on a pro rata basis. Impairment losses recognized in prior periods are assessed each reporting date if facts or circumstances indicate that the loss has decreased or no longer exists. An impairment loss is reversed if there has been a change in the estimates used to determine the recoverable amount. An impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

## (e) Business combinations

Transactions for the purchase of assets, where the assets acquired are deemed to constitute a business, are accounted for as business combinations. Using the acquisition method, identifiable assets acquired and liabilities assumed are measured at their acquisition-date fair values. Transaction costs related to the acquisition are expensed as incurred.

## (f) Share based compensation

The Company uses the fair value method for valuing share based compensation. Under this method, the compensation cost attributed to stock options and warrants is measured at fair value at the grant date and expensed over the vesting period with a corresponding increase to contributed surplus. A forfeiture rate is estimated on the grant date and is adjusted to reflect the actual number of options that vest. Upon the settlement of the stock options or warrants, the previously recognized value in contributed surplus is recorded as an increase to share capital.

**(g) Provisions**

Provisions are recognized when the Company has a present obligation as a result of a past event that can be estimated with reasonable certainty. Provisions are measured by estimating the cash flows that the Company would pay to be relieved of the obligation. To the extent that provisions are estimated using a present value technique, such amounts are determined by discounting the estimated future cash flows at a risk-free pre-tax rate. Provisions are not recognized for future operating losses.

*Decommissioning obligations*
The Company's activities give rise to dismantling, decommissioning, and site disturbance remediation activities. A provision is made for the estimated cost of abandonment and site restoration and capitalized in the relevant asset category. The capitalized amount is depreciated on a unit of production basis over the life of the associated proved plus probable reserves. Decommissioning obligations are measured at the present value of management's best estimate of the expenditure required to settle the present obligation at the reporting date. Subsequent to the initial measurement, the obligation is adjusted at the end of each period to reflect the passage of time, changes in the estimated future cash flows underlying the obligation, and changes in the risk-free rate. The increase in the provision due to the passage of time is recognized as accretion (within finance expenses) whereas increases or decreases due to changes in the estimated future cash flows or changes in the discount rate are capitalized. Actual costs incurred upon settlement of the decommissioning obligations are charged against the provision to the extent the provision was established.

**(h) Revenue**

The Company earns revenue from its production and sale of oil, natural gas and natural gas liquids ("NGLs") and from fees charged to third parties for processing and other services provided at facilities where the Company has an ownership interest.

Revenue from the sale of oil, natural gas and NGLs is recognized based on the consideration specified in contracts with customers. The Company recognizes revenue when control of the product transfers to the customer and collection is reasonable assured. This is generally at the point in time when the customer obtains legal title to the product which is when it is physically transferred to the pipeline or other transportation method agreed upon. Revenues from processing activities are recognized over time as processing occurs, and are generally billed monthly.

The Company evaluates its arrangements with third parties and partners to determine if the Company is acting as the principal or as an agent. In making this evaluation, management considers if the Company obtains control of the product delivered, which is indicated by the Company having the primary responsibility for the delivery of the product, having the ability to establish prices or having inventory risk. If the Company acts in the capacity of an agent rather than as a principal in a transaction, then revenue is recognized on a net basis, only reflecting the fee, if any, realized by the Company from the transaction.

Tariffs, tolls and fees charged to other entities for use of pipelines and facilities owned by the Company are evaluated by management to determine if these originate from contracts with customers or from incidental or collaborative arrangements. Tariffs, tolls and fees charged to other entities that are from contracts with customers are recognized in revenue when the related services are provided.

When allocating the transaction price realized in contracts with multiple performance obligations, management is required to make estimates of the prices at which the Company would sell the product separately to customers.

**(i) Finance income and expense**

Finance income and expense comprises interest expense, including interest on the credit facility, accretion on decommissioning obligations, and interest income earned on cash in the bank.

**(j) Income tax**

Income tax expense is comprised of current and deferred tax. Income tax expense is recognized in profit or loss except to the extent that it relates to items recognized directly in equity, in which case it is recognized in equity.

Current tax is the expected tax payable on the taxable income for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized on the temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized on the initial recognition of assets or liabilities in a transaction that is not a business combination. In addition, deferred tax is not recognized for taxable temporary differences arising on the initial recognition of goodwill. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date. Deferred tax assets and liabilities are offset if there is a legally enforceable right to offset, they relate to income taxes levied by the same tax authority on the same taxable entity, or on different tax entities, but they intend to settle current tax liabilities and assets on a net basis, or their tax assets and liabilities will be realized simultaneously.

A deferred tax asset is recognized to the extent that it is probable that future taxable earnings will be available against which the temporary difference can be utilized. Deferred tax assets are reviewed at each reporting date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

### (k) Per share amounts

Basic per share amounts are calculated by dividing the net earnings or loss attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the period. Diluted per share amounts are determined by adjusting the weighted average number of common shares outstanding during the period for the effects of dilutive instruments such as stock options, performance warrants and purchase warrants granted.

### (l) Flow-through shares

The Company, from time to time, may issue flow-through shares to finance a portion of its exploration capital expenditure program. Pursuant to the terms of the flow-through share agreements, the tax deductions associated with the exploration expenditures are renounced to the subscribers. On issuance of flow-through shares, the premium received on such shares, being the difference between the fair value ascribed to flow-through shares issued and the fair value that would have been received for common shares with no tax attributes, is recognized as a liability on the statement of financial position. When the exploration expenditures are incurred, the liability is drawn down, a deferred tax liability is recorded equal to the estimated amount of deferred income tax payable by the Company as a result of the foregone tax benefits, and the difference is recognized in profit or loss.

### (m) Government grants

Government grants are recognized when there is reasonable assurance that the Company will comply with the conditions attached to them and the grants will be received. When the conditions of a grant relate to income or expenses, it is recognized in the statement of operations in the period in which the expenditures are incurred or income is earned. When the conditions of a grant relate to an underlying asset, it is recognized as a reduction to the carrying amount of the related asset and amortized into earnings on a systematic basis over the expected useful life of the underlying asset through reduced depletion and depreciation expense.

### (n) Changes in accounting policies and new standards and interpretations not yet adopted

**IFRS 9, Financial Instruments**

Effective January 1, 2018, the Company adopted IFRS 9, “Financial Instruments” (“IFRS 9”) which replaced IAS 39, “Financial Instruments: Recognition and Measurement” (“IAS 39”). The Company applied the new standard retrospectively and, in accordance with the transitional provisions, comparative figures have not been restated. The adoption of IFRS 9 did not have a material impact on the Company’s financial statements.

The following table shows the original measurement categories under IAS 39 and the new measurement categories under IFRS 9 as at January 1, 2018 for each class of the Company’s financial assets and financial liabilities:

| | Measurement category | |
|---|---|---|
| **Financial instrument** | **IAS 39** | **IFRS 9** |
| Cash and cash equivalents | Loans and receivables | Amortized cost |
| Restricted cash | Loans and receivables | Amortized cost |
| Accounts receivable | Loans and receivables | Amortized cost |
| Accounts payable and accrued liabilities | Financial liabilities at amortized cost | Amortized cost |
| Borrowings under credit facility | Financial liabilities at amortized cost | Amortized cost |

There were no adjustments to the carrying amounts of the Company’s financial instruments as a result of the change in classification from IAS 39 to IFRS 9. The Company has not designated any financial instruments as FVOCI or FVTPL, nor does the Company use hedge accounting.

IFRS 9 replaces the ‘incurred loss’ model in IAS 39 with the ‘expected credit loss’ model. The application of the new expected credit loss model did not have a significant impact on the Company’s financial assets or result in any additional provision for impairment.

**IFRS 15, Revenue from Contracts with Customers**

The Company adopted IFRS 15, “Revenue from Contracts with Customers” (“IFRS 15”) effective January 1, 2018. IFRS 15 replaces IAS 18, “Revenue”, IAS 11, “Construction Contracts”, and several revenue-related interpretations.

The Company applied IFRS 15 to all of its contracts with customers using the modified retrospective method. Management reviewed the Company’s revenue streams and major contracts with customers using the IFRS 15 principles-based five-step model and concluded that there were no material changes to earnings or timing of when production revenue is recognized. However, it was determined that certain transactions in respect of third party marketing arrangements that optimized the Company’s transportation capacity were previously presented net within transportation expenses have been reclassified and presented separately in the financial statements for comparability with the current period presentation for those items, being the purchase and subsequent sale of natural gas. Also the accounting for certain processing charges incurred after control of the product transferred resulted in decreases to both oil and natural gas sales and operating expenses. There was no resultant impact on earnings, cash flow or financial position of the Company from these changes. The adoption of IFRS 15 does result in new disclosure requirements contained in note 21 of these financial statements.

**IFRS 16, Leases**

On January 13, 2016, the IASB issued IFRS 16, “Leases” (“IFRS 16”). The new standard is effective for annual periods beginning on or after January 1, 2019. IFRS 16 will replace IAS 17, “Leases”. This standard introduces a single lessee accounting model and requires a lessee to recognize assets and liabilities for all leases with a term of more than 12 months, unless the underlying asset is of low value. A lessee is required to recognize a right-of-use asset representing its right to use the underlying asset and a lease liability representing its obligation to make lease payments. The new standard is to be adopted either retrospectively or using a modified retrospective approach. IFRS 16 will be applied by Leucrotta on January 1, 2019 using the modified retrospective transition approach. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effect of IFRS 16 as an adjustment to the opening retained earnings (deficit) and applies the standard prospectively. The Company’s contract assessment remains ongoing and it has not yet determined the full extent of the impact of adoption, however, the Company expects an adjustment and recognition of a right-of-use asset and corresponding lease liability for its office lease.

## 4. RESTRICTED CASH

At December 31, 2018, the Company has $1.0 million (December 31, 2017 - $1.0 million) in a restricted corporate account to cross-guarantee a margin account for the President of the Company. The President is charged a fee by the Company and the margin account is also restricted until the cross-guarantee is removed. The margin account holds $3.4 million of securities of Leucrotta common shares and a margin payable of $1.0 million. The cross-guarantee is intended to be temporary in nature and will be removed as soon as practicable. The cross-guarantee has allowed the President to comply with corporate governance mandates.

## 5. EQUIPMENT HELD FOR SALE

| | **Net Book Value** |
|---|---|
| Balance, December 31, 2017 | - |
| Cost transferred from property, plant, and equipment | **4,794** |
| Accumulated depreciation transferred from property, plant, and equipment | **(480)** |
| Balance, December 31, 2018 | **4,314** |

At December 31, 2018, the Company had certain gas plant equipment held for sale of $4.3 million. The Company received deposits totaling $2.7 million (USD $2.0 million) during the fourth quarter of 2018 relating to the sale, which closed subsequent to December 31, 2018. The $2.7 million deposit was recognized in cash with an offsetting amount recognized in accounts payable. The deposit was held in trust until closing. Total proceeds of the subsequent sale were $5.9 million (USD $4.4 million) resulting in a gain of $1.6 million to be recognized in 2019.

## 6. PROPERTY, PLANT, AND EQUIPMENT

| Cost | Total |
|---|---|
| Balance, December 31, 2016 | 143,190 |
| Additions | 27,682 |
| Dispositions | (2,166) |
| Transfer from exploration and evaluation assets | 20,911 |
| Change in decommissioning obligations | 2,271 |
| Capitalized share based compensation | 190 |
| Balance, December 31, 2017 | 192,078 |
| Additions | **9,284** |
| Transfer from exploration and evaluation assets | **37,167** |
| Transfer to equipment held for sale | **(4,794)** |
| Change in decommissioning obligations | **830** |
| Capitalized share based compensation | **217** |
| **Balance, December 31, 2018** | **234,782** |

| Accumulated Depletion, Depreciation, and Impairment | Total |
|---|---|
| Balance, December 31, 2016 | 25,809 |
| Depletion and depreciation | 10,212 |
| Dispositions | (338) |
| Balance, December 31, 2017 | 35,683 |
| Transfer to equipment held for sale | **(480)** |
| Depletion and depreciation | **12,147** |
| **Balance, December 31, 2018** | **47,350** |

| Net Book Value | Total |
|---|---|
| December 31, 2017 | 156,395 |
| **December 31, 2018** | **187,432** |

During the year ended December 31, 2018, approximately $0.3 million (December 31, 2017 - $0.5 million) of directly attributable general and administrative costs were capitalized as expenditures on property, plant, and equipment.

### Depletion and depreciation

The calculation of depletion and depreciation expense for the year ended December 31, 2018 included an estimated $329.6 million (December 31, 2017 - $167.6 million) for future development costs associated with proved plus probable undeveloped reserves and excluded approximately $3.8 million (December 31, 2017 - $3.7 million) for the estimated salvage value of production equipment and facilities.

### Impairment

At December 31, 2018, the Company evaluated its property, plant, and equipment ("PP&E") CGUs for indicators of impairment or impairment reversals. During the year ended December 31, 2018, there were indicators of impairment identified in the Company's Montney CGU as a result of significant and sustained declines in the forward commodity prices for natural gas. An impairment test was performed based on value in use using the following commodity price estimates of the Company's independent reserve evaluators:

| Year | West Texas Intermediate Oil ($US/bbl) | Foreign Exchange Rate (USD/CDN) | Edmonton Light, Sweet Oil ($CDN/bbl) | AECO Gas Price ($CDN/mmbtu) |
|---|---|---|---|---|
| 2019 | 56.25 | 0.750 | 63.33 | 1.85 |
| 2020 | 63.00 | 0.770 | 75.32 | 2.29 |
| 2021 | 67.00 | 0.790 | 79.75 | 2.67 |
| 2022 | 70.00 | 0.810 | 81.48 | 2.90 |
| 2023 | 72.50 | 0.820 | 83.54 | 3.14 |
| 2024 | 75.00 | 0.825 | 86.06 | 3.23 |
| 2025 | 77.50 | 0.825 | 89.09 | 3.34 |
| 2026 | 80.41 | 0.825 | 92.62 | 3.41 |
| 2027 | 82.02 | 0.825 | 94.57 | 3.48 |
| 2028 | 83.66 | 0.825 | 96.56 | 3.54 |
| Escalate Thereafter | 2.0% per year | | 2.0% per year | 2.0% per year |

The impairment tests at December 31, 2018 were primarily based on the net present value of cash flows from oil and natural gas reserves at pre-tax discount rates ranging from 10 to 20 percent depending on the underlying composition and risk profile of the reserve category. The Company has determined that there was no impairment to its Montney CGU at December 31, 2018.

At December 31, 2017, the Company evaluated its PP&E CGUs for indicators of impairment or impairment reversals and as a result of this assessment management determined that an impairment test was not required to be performed.

## 7. EXPLORATION AND EVALUATION ASSETS

| | **Total** |
|---|---|
| Balance, December 31, 2016 | 88,540 |
| Property acquisitions | 35,550 |
| Additions | 30,282 |
| Transfer to property, plant, and equipment | (20,911) |
| Expensed | (6,240) |
| Capitalized share based compensation | 201 |
| Balance, December 31, 2017 | 127,422 |
| Additions | **27,396** |
| Transfer to property, plant, and equipment | **(37,167)** |
| Capitalized share based compensation | **829** |
| **Balance, December 31, 2018** | **118,480** |

Exploration and evaluation ("E&E") assets consist of the Company's exploration projects which are pending the determination of proved or probable reserves. Additions represent the Company's share of costs incurred on exploration and evaluation assets during the period, consisting primarily of undeveloped land and drilling costs until the drilling of the well is complete and the results have been evaluated.

During the year ended December 31, 2018, approximately $0.3 million (December 31, 2017 - $0.3 million) of directly attributable general and administrative costs were capitalized as expenditures on exploration and evaluation assets.

During the year ended December 31, 2017, the Company expensed $6.2 million of drilling and completion costs incurred for an exploratory well in the non-Montney CGU that was uneconomic and had no further expenditures planned.

### Impairment

At December 31, 2018, the Company evaluated its E&E assets for indicators of impairment or impairment reversals and as a result of this assessment management determined that an impairment test was not required to be performed.

## 8. CREDIT FACILITY

The Company has a $20.0 million revolving operating demand loan credit facility with a Canadian chartered bank. The revolving credit facility bears interest at prime plus a range of 0.50% to 2.50% and is secured by a $100 million fixed and floating charge debenture on the assets of the Company. The undrawn portion of the credit facility is subject to a standby fee in the range of 0.20% to 0.45%. At December 31, 2018, $2.4 million had been drawn on the revolving credit facility. At December 31, 2018, the Company had outstanding letters of guarantee of $3.6 million which reduce the amount that can be borrowed under the credit facility. The next review of the revolving credit facility by the bank is scheduled on or before May 31, 2019.

The Company's credit facility includes a covenant requiring the Company to maintain an adjusted working capital ratio of not less than one-to-one. The working capital ratio, as defined by its creditor, is calculated as current assets plus any undrawn amounts available on its credit facility less current liabilities excluding any current portion drawn on the credit facility. The Company was compliant with this covenant at December 31, 2018.

## 9. DECOMMISSIONING OBLIGATIONS

The Company's decommissioning obligations result from its ownership interest in oil and natural gas assets including well sites and gathering systems. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and facilities, and the estimated timing of the costs to be incurred in future periods. The total undiscounted amount of the estimated cash flows (adjusted for inflation at 2% per year) required to settle the decommissioning obligations is approximately $15.7 million (December 31, 2017 - $14.7 million) which is estimated to be incurred over the next 31 years. At December 31, 2018, a risk-free rate of 2.12% (December 31, 2017 - 2.15%) was used to calculate the net present value of the decommissioning obligations.

| | **Year Ended December 31, 2018** | Year Ended December 31, 2017 |
|---|---|---|
| Balance, beginning of year | **8,718** | 6,820 |
| Provisions incurred | **458** | 1,604 |
| Provisions settled | **(176)** | (296) |
| Dispositions | **-** | (239) |
| Revisions in estimated cash flows | **301** | 435 |
| Revisions due to change of discount rates | **71** | 232 |
| Accretion | **200** | 162 |
| **Balance, end of year** | **9,572** | 8,718 |

## 10. SHAREHOLDERS' CAPITAL

The Company is authorized to issue an unlimited number of voting common shares, an unlimited number of non-voting common shares, Class A preferred shares, issuable in series, and Class B preferred shares, issuable in series. No non-voting common shares or preferred shares have been issued.

| **Voting Common Shares** | **Number** | **Amount** |
|---|---|---|
| Balance, December 31, 2016 | 165,227 | 213,875 |
| Share issuances | 35,185 | 80,001 |
| Share issue costs | - | (4,394) |
| Flow-through share premium | - | (833) |
| Exercise of warrants and stock options | 85 | 138 |
| Balance, December 31, 2017 | 200,497 | 288,787 |
| Exercise of stock options | **28** | **50** |
| **Balance, December 31, 2018** | **200,525** | **288,837** |

## 11. SHARE BASED COMPENSATION PLANS

### Stock options

The Company has authorized and reserved for issuance 20.1 million common shares under a stock option plan enabling certain officers, directors, employees, and consultants to purchase common shares. The Company will not issue options exceeding 10% of the shares outstanding at the time of the option grants (the performance warrants described below are aggregated with any options for the 10% limit). Under the plan, the exercise price of each option equals the market price of the Company's shares on the date of the grant and an option's maximum term is ten years. At December 31, 2018, 11.4 million options were outstanding at an average exercise price of $1.25 per share.

| | **Number of Options** | **Weighted Average Exercise Price ($)** |
|---|---|---|
| Balance, December 31, 2016 | 8,920 | 1.09 |
| Granted | 2,626 | 1.78 |
| Exercised | (76) | 1.09 |
| Balance, December 31, 2017 | 11,470 | 1.25 |
| Granted | **25** | **1.70** |
| Exercised | **(28)** | **1.24** |
| Forfeited | **(45)** | **1.47** |
| **Balance, December 31, 2018** | **11,422** | **1.25** |
| | | |
| **Exercisable, December 31, 2018** | **9,650** | **1.15** |

The following table summarizes the stock options outstanding and exercisable at December 31, 2018:

| | **Options Outstanding** | | | **Options Exercisable** | |
|---|---|---|---|---|---|
| **Exercise Price** | **Number** | **Weighted Average Remaining Life (years)** | **Weighted Average Exercise Price** | **Number** | **Weighted Average Exercise Price** |
| $0.80 to $1.00 | 4,189 | 2.9 | 0.87 | 4,187 | 0.87 |
| $1.01 to $1.30 | 4,582 | 2.0 | 1.29 | 4,582 | 1.29 |
| $1.31 to $1.78 | 2,651 | 4.7 | 1.78 | 881 | 1.78 |
| | 11,422 | 2.9 | 1.25 | 9,650 | 1.15 |

The Company accounts for its share based compensation plans using the fair value method. Under this method, compensation cost is charged to earnings over the vesting period for stock options and warrants granted to officers, directors, employees, and consultants with a corresponding increase to contributed surplus.

The fair value of the stock options granted were estimated on the date of grant using the Black-Scholes-Merton option pricing model with the following weighted average assumptions:

| | **December 31, 2018** | December 31, 2017 |
|---|---|---|
| Risk-free interest rate (%) | **1.9** | 1.7 |
| Expected life (years) | **4.0** | 4.0 |
| Expected volatility (%) | **51.3** | 52.8 |
| Expected dividend yield (%) | **-** | - |
| Forfeiture rate (%) | **0.2** | 0.2 |
| Weighted average fair value of options granted ($ per option) | **0.71** | 0.75 |

During the year ended December 31, 2018, the Company recognized $2.6 million (December 31, 2017 - $1.1 million) of share based compensation related to the stock options (including the stock option modification, see below). At December 31, 2018 there was $0.7 million remaining as unrecognized share based compensation related to both the original stock option grants and the modification incremental fair value.

**Stock option modification**

In May 2018, the expiry term for previously granted stock options was extended to 6 years from the original term of 4 or 5 years. The incremental fair value of the stock option modification was $1.5 million and $1.4 million was recognized during the year ended December 31, 2018 based on the percentage of modified options that were vested. The incremental fair value was estimated immediately before and as at the date of modification using a Black-Scholes-Merton option pricing model with the following weighted average assumptions:

| | **Prior to modification** | **Post modification** |
|---|---|---|
| Risk-free interest rate (%) | 1.9 | 2.0 |
| Expected life (years) | 1.8 | 3.5 |
| Expected volatility (%) | 39.4 | 45.5 |
| Expected dividend yield (%) | - | - |
| Forfeiture rate (%) | - | - |
| Weighted average fair value of options granted ($ per option) | 0.86 | 0.99 |

**Performance Warrants**

The Company has 7.5 million performance warrants outstanding to certain officers, directors, employees, and consultants to purchase common shares at an exercise price of $1.70. The performance warrants expire on August 15, 2020 and are subject to both time vesting, which has been met, and performance vesting as follows:

| **30 day Volume Weighted Average Trading Price of the Common Shares ($)** | **Percentage of Warrants Vested** |
|---|---|
| 1.87 | 20% |
| 2.04 | 40% |
| 2.21 | 60% |
| 2.38 | 80% |
| 2.55 | 100% |

| | **Number of Warrants** | **Exercise Price** |
|---|---|---|
| Balance, December 31, 2016 | 7,500 | 1.70 |
| Exercised | (9) | 1.70 |
| Balance, December 31, 2017 | 7,491 | 1.70 |
| Forfeited | **(6)** | **1.70** |
| **Balance, December 31, 2018** | **7,485** | **1.70** |
| **Exercisable, December 31, 2018** | **4,491** | **1.70** |

During the year ended December 31, 2018, the Company recognized $0.8 million (December 31, 2017 - $0.5 million) of share based compensation related to the performance warrants (including the performance warrant modification, see below). At December 31, 2018 there was $0.2 million remaining as unrecognized share based compensation related to the performance warrant modification incremental fair value. No new performance warrants were granted during the year ended December 31, 2018. The remaining life of the performance warrants at December 31, 2018 is 1.6 years (December 31, 2017 - 1.6 years).

**Performance warrant modification**

In May 2018, the expiry term for previously granted performance warrants was extended to 6 years from the original term of 5 years. The incremental fair value of the performance warrant modification was $1.0 million and $0.8 million was recognized during the year ended December 31, 2018 based on the percentage of modified performance warrants that were vested. The incremental fair value was estimated immediately before and as at the date of modification using a Black-Scholes-Merton option pricing model with the following weighted average assumptions:

| | Prior to modification | Post modification |
|---|---|---|
| Risk-free interest rate (%) | 1.9 | 1.9 |
| Expected life (years) | 1.2 | 2.2 |
| Expected volatility (%) | 36.0 | 38.0 |
| Expected dividend yield (%) | - | - |
| Forfeiture rate (%) | - | - |
| Weighted average fair value of warrants granted ($ per warrant) | 0.32 | 0.45 |

**Purchase Warrants**

The Company has 7.65 million purchase warrants outstanding to certain officers, directors, employees, and consultants to purchase common shares at an exercise price of $2.04 expiring on September 12, 2020 that are fully vested.

| | Number of Warrants | Exercise Price |
|---|---|---|
| **Balance, December 31, 2016, 2017 and 2018** | **7,650** | **2.04** |
| **Exercisable, December 31, 2018** | **7,650** | **2.04** |

During the year ended December 31, 2018, the Company recognized $1.3 million (December 31, 2017 - $0.4 million) of share based compensation related to the purchase warrants (including the purchase warrant modification, see below). At December 31, 2018 there was $nil remaining as unrecognized share based compensation related to the purchase warrants. No new purchase warrants were granted during the year ended December 31, 2018. The remaining life of the purchase warrants at December 31, 2018 is 1.7 years (December 31, 2017 - 1.7 years).

**Purchase warrant modification**

In May 2018, the expiry term for previously granted purchase warrants was extended to 6 years from the original term of 5 years. The incremental fair value of the purchase warrant modification was $1.3 million and $1.3 million was recognized during the year ended December 31, 2018 based on the percentage of modified purchase warrants that were vested. The incremental fair value was estimated immediately before and as at the date of modification using a Black-Scholes-Merton option pricing model with the following weighted average assumptions:

| | Prior to modification | Post modification |
|---|---|---|
| Risk-free interest rate (%) | 1.9 | 1.9 |
| Expected life (years) | 1.3 | 2.3 |
| Expected volatility (%) | 35.3 | 39.7 |
| Expected dividend yield (%) | - | - |
| Forfeiture rate (%) | - | - |
| Weighted average fair value of warrants granted ($ per warrant) | 0.28 | 0.44 |

## 12. PER SHARE AMOUNTS

The following table summarizes the weighted average number of shares used in the basic and diluted net loss per share calculations:

| | **December 31, 2018** | December 31, 2017 |
|---|---|---|
| Weighted average number of shares - basic and diluted | **200,520** | 189,377 |

For the year ended December 31, 2018, 11.4 million stock options, 7.7 million purchase warrants and 7.5 million performance warrants (December 31, 2017 - 11.5 million stock options, 7.7 million purchase warrants and 7.5 million performance warrants) were excluded from the weighted-average share calculations because they were anti-dilutive due to the net loss.

## 13. KEY MANAGEMENT PERSONNEL

The Company considers its directors and executives to be key management personnel. The key management personnel compensation is comprised of the following:

| | December 31, 2018 | December 31, 2017 |
|---|---|---|
| Short-term wages and benefits | **2,219** | 1,724 |
| Share based compensation [1] | **3,619** | 1,487 |
| Total [2,3] | **5,838** | 3,211 |

(1) Represents the amortization of share based compensation expense associated with the Company's share based compensation plans granted to key management personnel inclusive of any capitalized portion.
(2) Balances outstanding and payable at December 31, 2018 were $nil (December 31, 2017 - $nil).
(3) At December 31, 2018, key management personnel included 12 individuals (December 31, 2017 – 12 individuals).

## 14. FINANCE EXPENSE

Finance expense includes the following:

| | December 31, 2018 | December 31, 2017 |
|---|---|---|
| Interest expense | **141** | 125 |
| Accretion of decommissioning obligations | **200** | 162 |
| Finance expense | **341** | 287 |

## 15. INCOME TAXES

The provision for income taxes in the statements of operations and comprehensive loss reflects an effective tax rate which differs from the expected statutory tax rate. The differences were accounted for as follows:

| | December 31, 2018 | December 31, 2017 |
|---|---|---|
| Loss before taxes | **43** | 9,055 |
| Statutory income tax rate | **27.0%** | 26.5% |
| Expected income tax recovery | **12** | 2,400 |
| Increase (decrease) in income tax recovery resulting from: | | |
| Share based compensation and other non-deductible amounts | **(1,017)** | (439) |
| Expenditures renounced under flow-through shares | **-** | (1,350) |
| Change in statutory income tax rate | **-** | 160 |
| Change in unrecognized deferred income tax asset | **1,005** | (771) |
| | **-** | - |
| Flow-through share premium | **-** | 833 |
| Income tax recovery | **-** | 833 |

The tax rate consists of the combined federal and provincial statutory tax rates for the Company for the years ended December 31, 2018 and December 31, 2017. The change in the statutory income tax rate at December 31, 2017 is due to the British Columbia corporate tax rate increasing from 11.0% to 12.0% effective January 1, 2018.

At December 31, 2018 and 2017, the Company has an unrecognized net deferred income tax asset based on the independently evaluated reserve report as cash flows are not expected to be sufficient to realize the deferred income tax asset at this time.

At December 31, 2018, the Company has estimated federal tax pools of $325.3 million (December 31, 2017 - $304.4 million) available for deduction against future taxable income.

Unrecognized deductible temporary differences are as follows:

| | December 31, 2018 | December 31, 2017 |
|---|---|---|
| Oil and natural gas properties and equipment | **10,230** | 13,387 |
| Decommissioning obligations | **9,572** | 8,718 |
| Share issue costs | **3,393** | 4,804 |
| Non-capital losses | **4,446** | 4,454 |
| Unrecognized deductible temporary differences | **27,641** | 31,363 |

Non-capital losses of $4.4 million will expire between 2035 and 2036.

## 16. FAIR VALUE OF FINANCIAL INSTRUMENTS

**Cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities, and credit facility**

The fair value of cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities, and credit facility at December 31, 2018 and December 31, 2017 approximated their carrying value due to their short term to maturity and the credit facility bears interest at floating rates where the premium charged is indicative of the Company's current credit spreads.

The Company classified the fair value of its financial instruments at fair value according to the following hierarchy based on the amount of observable inputs used to value the instrument:

- Level 1 – observable inputs, such as quoted market prices in active markets
- Level 2 – inputs, other than the quoted market prices in active markets, which are observable, either directly or indirectly
- Level 3 – unobservable inputs for the asset or liability in which little or no market data exists, therefore requiring an entity to develop its own assumptions

During the years ended December 31, 2018 and 2017, there were no transfers between level 1, level 2, and level 3 classified assets and liabilities.

## 17. FINANCIAL RISK MANAGEMENT

The Company's activities expose it to a variety of financial risks that arise as a result of its exploration, development, production, and financing activities. The Company employs risk management strategies and policies to ensure that any exposure to risk is in compliance with the Company's business objectives and risk tolerance levels. Risk management is ultimately established by the Board of Directors and is implemented by management. As required under the terms of the Company's credit facility, the Company is subject to an upper limit on fixed price contracts of 65% of its future production up to a three year period.

**Market risk**

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk is comprised of foreign currency risk, interest rate risk, and other price risk, such as commodity price risk. The objective of market risk management is to manage and control market price exposures within acceptable limits, while maximizing returns. The Company may use financial derivatives or physical delivery sales contracts to manage market risks. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors.

*Foreign exchange risk*
The prices received by the Company for the production of oil, natural gas, and NGLs are primarily determined in reference to US dollars, but are settled with the Company in Canadian dollars. The Company's cash flow from commodity sales will therefore be impacted by fluctuations in foreign exchange rates. The Company does not currently have any foreign exchange contracts in place.

*Interest rate risk*
The Company is exposed to interest rate risk when it borrows funds at floating interest rates. The Company currently does not use interest rate hedges or fixed interest rate contracts to manage the Company's exposure to interest rate fluctuations. The amount drawn on the Company's credit facility at December 31, 2018 was $2.4 million.

*Commodity price risk*
Oil and natural gas prices are impacted by not only the relationship between the Canadian and US dollar but also by world economic events that dictate the levels of supply and demand. The Company's oil, natural gas, and NGLs production is marketed and sold on the spot market to area aggregators based on daily spot prices that are adjusted for product quality and transportation costs. The Company's cash flow from product sales will therefore be impacted by fluctuations in commodity prices. A $1.00/boe increase or decrease in commodity prices would have impacted the net loss by approximately $1.3 million for the year ended December 31, 2018 (December 31, 2017 - $1.0 million).

The Company did not enter into commodity price contracts to manage future cash flows as at December 31, 2018.

**Credit risk**

Credit risk represents the financial loss that the Company would suffer if the Company's counterparties to a financial asset fail to meet or discharge their obligation to the Company. A substantial portion of the Company's accounts receivable and deposits are with customers and joint interest partners in the oil and natural gas industry and are subject to normal industry credit risks. The Company generally grants unsecured credit but routinely assesses the financial strength of its customers and joint interest partners.

The Company sells the majority of its production to three petroleum and natural gas marketers and therefore is subject to concentration risk. Historically, the Company has not experienced any collection issues with its oil and natural gas marketers. Joint interest receivables are typically collected within one to three months of the joint interest billing being issued to the partner. The Company attempts to mitigate the risk from joint interest receivables by obtaining partner approval for significant capital expenditures prior to the expenditure being incurred. The Company does not typically obtain collateral from petroleum and natural gas marketers or joint interest partners; however, in certain circumstances, the Company may cash call a partner in advance of expenditures being incurred.

The maximum exposure to credit risk is represented by the carrying amount of cash and cash equivalents, restricted cash, and accounts receivable on the statement of financial position. At December 31, 2018, $2.2 million (76%) of the Company's outstanding accounts receivable were current and $0.4 million (15%) were outstanding for more than 90 days. During the year ended December 31, 2018, the Company deemed $nil of outstanding accounts receivable to be uncollectable (December 31, 2017 - $0.1 million).

Cash and cash equivalents consists of bank balances placed with a financial institution with strong investment grade ratings which management believes the risk of loss to be remote.

**Liquidity risk**

Liquidity risk is the risk that the Company will not be able to meet its financial obligations as they become due. The Company's processes for managing liquidity risk include ensuring, to the extent possible, that it will have sufficient liquidity to meet its liabilities when they become due. The Company prepares annual, quarterly, and monthly capital expenditure budgets, which are monitored and updated as required, and requires authorizations for expenditures on projects to assist with the management of capital. In managing liquidity risk, the Company ensures that it has access to additional financing, including potential equity issuances and additional debt financing. The Company also mitigates liquidity risk by maintaining an insurance program to minimize exposure to insurable losses.

See note 23 for a summary of contractual commitments at December 31, 2018. The Company's accounts payable and accrued liabilities and credit facility are all due within the current operating period.

## 18. CAPITAL MANAGEMENT

The Company's objectives when managing capital are to maintain a flexible capital structure, which optimizes the cost of capital at an acceptable risk, and to maintain investor, creditor, and market confidence to sustain future development of the business.

The Company manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of the underlying assets. The Company considers its capital structure to include shareholders' equity and working capital (current assets less current liabilities). To maintain or adjust the capital structure, the Company may, from time to time, issue shares, raise debt, or adjust its capital spending to manage its current and projected debt levels.

| | **December 31, 2018** | December 31, 2017 |
|---|---|---|
| Shareholders' equity | **298,442** | 293,759 |
| Working capital | **2,102** | 18,660 |

In addition, management prepares annual, quarterly, and monthly budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment. The Company's share capital is not subject to external restrictions, however, the Company's credit facility includes a covenant requiring the Company to maintain a working capital ratio of not less than one-to-one (see note 8). There were no changes in the Company's approach to capital management from the previous year.

## 19. SUPPLEMENTAL DISCLOSURES

**Presentation of expenses**

The Company's statements of operations and comprehensive loss is prepared primarily by nature of expense, with the exception of employee compensation costs which are included in general and administrative expenses. Included in general and administrative expenses for the year ended December 31, 2018 are $4.0 million of wages and benefits (December 31, 2017 - $3.3 million).

## 20. SUPPLEMENTAL CASH FLOW INFORMATION

| | **December 31, 2018** | December 31, 2017 |
|---|---|---|
| Accounts receivable | **1,208** | (2,586) |
| Prepaid expenses and deposits | **181** | (174) |
| Accounts payable and accrued liabilities | **(3,891)** | 913 |
| Deposit on equipment held for sale | **(2,729)** | - |
| Change in non-cash working capital | **(5,231)** | (1,847) |
| | | |
| Relating to: | | |
| Investing | **(5,707)** | (852) |
| Operating | **476** | (995) |
| Change in non-cash working capital | **(5,231)** | (1,847) |

## 21. REVENUE

The Company sells its production pursuant to fixed or variable price contracts. The transaction price for variable priced contracts is based on the commodity price, adjusted for quality, location or other factors, whereby each component of the pricing formula can be either fixed or variable, depending on the contract terms. Commodity prices are based on market indices that are determined on a monthly or daily basis. Under the contracts, the Company is required to deliver variable volumes of oil, natural gas liquids or natural gas to the contract counterparty. Revenue is recognized when a unit of production is delivered to the contract counterparty. The amount of revenue recognized is based on the agreed transaction price, whereby any variability in revenue relates specifically to the Company's efforts to transfer production, and therefore the resulting revenue is allocated to the production delivered in the period during which the variability occurs. As a result, none of the variable revenue is considered constrained.

The contracts generally have a term of one year or less, whereby delivery takes place throughout the contract period. Revenues are typically collected on the 25th day of the month following production.

The following table presents the Company's oil and natural gas revenues disaggregated by revenue source:

| | **December 31, 2018** | December 31, 2017 |
|---|---|---|
| Oil and condensate | **16,436** | 14,350 |
| Other natural gas liquids | **4,268** | 2,616 |
| Natural gas | **11,344** | 9,158 |
| Oil and natural gas sales | **32,048** | 26,124 |

Under certain marketing arrangements the Company will transfer title of its natural gas production to a third-party marketing company who will subsequently redeliver the natural gas production to an end customer by utilizing the Company's pipeline capacity. This portion representing the sale of transportation services is presented within natural gas revenue which is disaggregated in the below table by type:

| | **December 31, 2018** | December 31, 2017 |
|---|---|---|
| Natural gas production sales | **8,034** | 6,037 |
| Transportation revenue | **3,310** | 3,121 |
| Natural gas sales | **11,344** | 9,158 |

The following table presents the Company's processing and marketing revenues disaggregated by revenue source:

| | **December 31, 2018** | December 31, 2017 |
|---|---|---|
| Sale of purchased natural gas | **361** | 1,838 |
| Processing revenue | **884** | - |
| Marketing revenue | **507** | - |
| Processing and marketing revenue | **1,752** | 1,838 |

The Company purchases natural gas for resale on a monthly basis in order to optimize its transportation capacity and satisfy take or pay commitments (see note 22).

The Company's revenue was generated entirely in the province of British Columbia. The majority of revenue resulted from sales whereby the transaction price was based on index prices. Of total oil and natural gas sales, three customers represented combined sales of 94% for the year ended December 31, 2018 (December 31, 2017 - two customers represented combined sales of 99%).

During the year ended December 31, 2018, the Company began receiving credits to offset royalties from the British Columbia Government's Infrastructure Royalty Credit Program resulting from infrastructure built in 2017 and wells drilled and tied-into the related infrastructure. During the year ended December 31, 2018, the Company realized credits of $1.8 million (December 31, 2017 - $nil) to offset royalties payable.

## 22. TRANSPORTATION AND MARKETING EXPENSES

| | **December 31, 2018** | December 31, 2017 |
|---|---|---|
| Pipeline tariffs from firm transportation agreements | **4,080** | 4,046 |
| Purchased natural gas | **270** | 1,507 |
| Transportation and marketing expenses | **4,350** | 5,553 |

## 23. COMMITMENTS

The following is a summary of the Company's contractual obligations and commitments at December 31, 2018:

| | **2019** | **2020** | **2021** | **2022** | **2023** | **Thereafter** | **Total** |
|---|---|---|---|---|---|---|---|
| Office leases | 320 | 320 | 267 | - | - | - | 907 |
| Equipment leases | 122 | - | - | - | - | - | 122 |
| Firm transportation agreements | 5,909 | 6,292 | - | - | - | - | 12,201 |
| | 6,351 | 6,612 | 267 | - | - | - | 13,230 |

Transportation commitments include contracts to transport natural gas and NGLs through third-party owned pipeline systems. The Company currently has commitments of 16 mmcf/d escalating to 33.3 mmcf/d in November 2019.

# CORPORATE INFORMATION

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