Q1 2018 RESULTS

FINANCIAL AND OPERATING RESULTS FOR THE THREE MONTHS ENDED **MARCH 31, 2018**

LEUCROTTA EXPLORATION INC.

HIGHLIGHTS

- Increased production 122% to 4,180 boe/d in Q1 2018 from 1,881 boe/d in Q1 2017 (increased 10% from 3,802 boe/d in Q4 2017).
- Increased adjusted funds flow 393% to $6.4 million in Q1 2018 from $1.3 million in Q1 2017 (increased 43% from $4.5 million in Q4 2017).
- Drilled 3 Lower Montney delineation wells which are expected to be completed in the second half of 2018.

FINANCIAL RESULTS	THREE MONTHS ENDED MARCH 31		
($000s, except per share amounts)	**2018**	2017	% Change
OIL AND NATURAL GAS SALES	**10,426**	4,783	118
ADJUSTED FUNDS FLOW(1)	**6,387**	1,296	393
Per share - basic and diluted	**0.03**	0.01	200
NET EARNINGS (LOSS)	**2,546**	(878)	390
Per share - basic and diluted	**0.01**	(0.01)	200
CAPITAL EXPENDITURES AND ACQUISITIONS	**11,460**	18,518	(38)
WORKING CAPITAL	**13,613**	8,889	53
COMMON SHARES OUTSTANDING (000S)			
Weighted average - basic	**200,516**	165,239	21
Weighted average - diluted	**203,307**	165,239	23
End of period - basic	**200,517**	165,261	21
End of period - fully diluted	**227,133**	189,297	20

(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 "Adjusted Funds Flow" section in the MD&A for a reconciliation from cash flow from operating activities.

OPERATING RESULTS [1]

	Three Months Ended March 31		
	2018	2017	% Change
Daily production			
Oil and NGLs (bbls/d)	**1,144**	514	123
Natural gas (mcf/d)	**18,216**	8,197	122
Oil equivalent (boe/d)	**4,180**	1,881	122
Oil and natural gas sales			
Oil and NGLs ($/bbl)	**62.08**	57.81	7
Natural gas ($/mcf)	**2.46**	2.85	(14)
Oil equivalent ($/boe)	**27.71**	28.26	(2)
Royalties			
Oil and NGLs ($/bbl)	**-**	3.46	(100)
Natural gas ($/mcf)	**-**	0.15	(100)
Oil equivalent ($/boe)	**-**	1.59	(100)
Net operating expenses [2]			
Oil and NGLs ($/bbl)	**6.32**	11.75	(46)
Natural gas ($/mcf)	**0.78**	1.08	(28)
Oil equivalent ($/boe)	**5.14**	7.93	(35)
Net transportation expenses [2]			
Oil and NGLs ($/bbl)	**2.55**	3.73	(32)
Natural gas ($/mcf)	**0.43**	0.96	(55)
Oil equivalent ($/boe)	**2.59**	5.21	(50)
Operating netback [2]			
Oil and NGLs ($/bbl)	**53.21**	38.87	37
Natural gas ($/mcf)	**1.25**	0.66	89
Oil equivalent ($/boe)	**19.98**	13.53	48
Depletion and depreciation ($/boe)	**(9.37)**	(10.38)	(10)
General and administrative expenses ($/boe)	**(3.23)**	(6.40)	(50)
Share based compensation ($/boe)	**(0.72)**	(2.24)	(68)
Finance expense ($/boe)	**(0.16)**	(0.23)	(30)
Finance income ($/boe)	**0.26**	0.53	(51)
Net earnings (loss) ($/boe)	**6.76**	(5.19)	230

(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 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 Expenses" and "Operating Netback" sections in the MD&A for reconciliations from operating expenses, transportation expenses, and net earnings (loss) per boe, respectively.

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

May 28, 2018

The MD&A should be read in conjunction with the unaudited condensed interim financial statements and related notes for the three months ended March 31, 2018 and the audited financial statements and MD&A for the year ended December 31, 2017. The unaudited condensed interim 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. Certain prior period comparative figures have been reclassified to conform to presentation in the current period.

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 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 uses adjusted funds flow to analyze performance and considers it 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, if any. 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 "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 expenses, represents the cash margin for every barrel of oil equivalent sold. Operating netback per boe is reconciled to net earnings (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 expenses is calculated as transportation expenses less marketing revenues. Management uses net transportation expenses to determine the current periods' cash cost of transportation expenses less marketing revenue and net transportation 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 Q1 2018, Leucrotta continued with the delineation of the Lower Montney turbidite zone on its 140 section contiguous block of land at Doe/Mica. Three significant step-out delineation wells were drilled but not completed as at this date. The wells were positioned to the east and north of Leucrotta's current development to prove the level of productivity substantially beyond current productive boundaries. Leucrotta will start the completion of these wells in July and report on level of productivity in early fall. The new wells were set up to be completed with higher intensity fracs (40 or 50 frac stages over approximately 1 mile laterals). By the end of the year, the delineation phase for the Lower Montney will be completed.

From an operations perspective, the previous 40 and 50 stage frac wells (8-22 and 9-33) continue to outperform expectations and Leucrotta is very pleased with the longer term production data to date. Production and cash flow reached all time corporate highs due in part to some flush production and favourable commodity prices during the quarter. In Q2 2018, production will be affected by approximately 500 boe/d that was recently shut-in due to pricing and some facility maintenance. This production was flowing through third party facilities and has higher operating costs than average. Leucrotta estimates it will average 3,600 boe/d for 2018.

Leucrotta continues to maintain a strong balance sheet with net working capital of $13.6 million and no debt at the end of Q1 2018 and has projected to have positive working capital at year-end with an unused bank credit facility of $20 million based on the previously released capital budget of $33 million.

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

SUMMARY OF FINANCIAL RESULTS

	Three Months Ended March 31		
($000s, except per share amounts)	**2018**	2017	% Change
Oil and natural gas sales	**10,426**	4,783	118
Adjusted funds flow	**6,387**	1,296	393
Per share - basic and diluted	**0.03**	0.01	200
Net earnings (loss)	**2,546**	(878)	390
Per share - basic and diluted	**0.01**	(0.01)	200
Total assets	**313,105**	241,318	30
Total long-term liabilities	**9,212**	7,153	29
Working capital	**13,613**	8,889	53

The Company experienced a substantial increase in oil and natural gas sales, adjusted funds flow and net earnings for the first quarter of 2018 compared to the same period in 2017. This was mainly due to significant production growth from successful drilling at Doe/Mica in the Montney formation during 2017.

PRODUCTION	Three Months Ended March 31		
	2018	2017	% Change
Average Daily Production			
Oil and NGLs (bbls/d)	**1,144**	514	123
Natural gas (mcf/d)	**18,216**	8,197	122
Combined (boe/d)	**4,180**	1,881	122

Daily production for the first quarter of 2018 increased substantially to 4,180 boe/d from 1,881 boe/d for the comparative quarter in 2017. The increase in production was the result of successful drilling at Doe/Mica (8-4, A8-22, 9-33, 4-12, and 12-6 all commenced production subsequent to Q1 2017).

Leucrotta's production profile for the first quarter of 2018 remained consistent in liquids weighting from the comparative quarter in 2017. The Q1 2018 weighting was 73% natural gas (Q1 2017 - 73%) and 27% oil and NGLs (Q1 2017 - 27%).

OIL AND NATURAL GAS SALES	Three Months Ended March 31		
($000s)	**2018**	2017	% Change
Oil and NGLs	**6,393**	2,677	139
Natural gas	**4,033**	2,106	92
Total	**10,426**	4,783	118
Average Sales Price			
Oil and NGLs ($/bbl)	**62.08**	57.81	7
Natural gas production sales and transportation revenue ($/mcf)	**2.46**	2.85	(14)
Combined ($/boe)	**27.71**	28.26	(2)

Revenue totaled $10.4 million for the first quarter of 2018, up 118% from $4.8 million for the comparative quarter in 2017. The increase was mainly due to the 122% growth in production from the successful drilling at Doe/Mica.

PROCESSING AND MARKETING REVENUE	Three Months Ended March 31		
($000s)	**2018**	2017	% Change
Sale of purchased natural gas	**-**	1,239	(100)
Processing revenue	**246**	-	100
Marketing revenue	**152**	-	100
Total	**398**	1,239	(68)

The purchase and sale of natural gas is done to optimize firm transportation capacity. These transactions occurred in Q1 2017 when the Company had more available pipeline capacity than it used. In Q1 2018, the Company used more of its pipeline capacity as production volumes increased significantly from the comparative quarter as noted above. 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 March 31**		
	2018	2017	% Change
Oil and NGLs			
Corporate price ($CDN/bbl)	**62.08**	57.81	7
Canadian light sweet ($CDN/bbl)	**70.09**	67.74	3
West Texas Intermediate ($US/bbl)	**62.87**	51.90	21
Natural gas			
Corporate price ($CDN/mcf)	**2.46**	2.85	(14)
AECO price ($CDN/mcf)	**2.06**	2.69	(23)
Exchange rate			
CDN/US dollar average exchange rate	**0.7908**	0.7557	5

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 88.6% of Canadian light sweet prices for the first quarter of 2018, up marginally from 85.3% for the comparative quarter in 2017. Corporate average natural gas prices were 119.4% of AECO price for the first quarter of 2018, up from 105.9% for the comparative quarter in 2017 due to new marketing contracts with a portion of natural gas sales priced off indexes other than AECO.

Leucrotta's liquids mix during the first quarter of 2018 was approximately 72% oil, condensate and pentanes, 8% butane and 20% propane (Q1 2017 - 82% oil, condensate and pentanes, 6% butane and 12% propane).

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 March 31**		
($000s)	**2018**	2017	% Change
Oil and NGLs	**-**	160	(100)
Natural gas	**-**	109	(100)
Total	**-**	269	(100)
Average Royalty Rate (% of sales)			
Oil and NGLs	**-**	6.0	(100)
Natural gas	**-**	5.2	(100)
Combined	**-**	5.6	(100)

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 three months ended March 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. The Company realized $0.8 million of credits to offset royalties payable in Q1 2018 and has $0.4 million of credits remaining to partially offset royalties in Q2 2018. 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 $2.5 million in remaining royalty credits.

NET OPERATING EXPENSES	Three Months Ended March 31		
($000s)	**2018**	2017	% Change
Oil and NGLs	**651**	544	20
Natural gas	**1,527**	798	91
Operating expenses	**2,178**	1,342	62
Less: processing revenue	**(246)**	-	100
Net operating expenses (non-GAAP)	**1,932**	1,342	44

Average net operating expenses			
Oil and NGLs ($/bbl)	**6.32**	11.75	(46)
Natural gas ($/mcf)	**0.78**	1.08	(28)
Combined ($/boe)	**5.14**	7.93	(35)

Per unit net operating expenses decreased to $5.14/boe in Q1 2018 from $7.93/boe in Q1 2017. The large decrease was the result of increased production from successful drilling and the tie-in of those wells into the Company's Doe gas plant, gaining economies of scale over the larger production base.

NET TRANSPORTATION AND MARKETING EXPENSES	Three Months Ended March 31		
($000s)	**2018**	2017	% Change
Oil and NGLs transportation	**263**	173	52
Natural gas transportation	**865**	862	-
Transportation expenses	**1,128**	1,035	9
Purchased natural gas	**-**	1,086	(100)
Transportation and marketing expenses	**1,128**	2,121	(47)
Less: sale of purchased natural gas	**-**	(1,239)	(100)
Less: marketing revenue	**(152)**	-	100
Net transportation expenses (non-GAAP)	**976**	882	11

Average net transportation and marketing expenses			
Oil and NGLs ($/bbl)	**2.55**	3.73	(32)
Natural gas ($/mcf)	**0.43**	0.96	(55)
Combined ($/boe)	**2.59**	5.21	(50)

Net transportation expenses are mainly third-party pipeline tariffs from firm transportation agreements to deliver production to the purchasers at main hubs. Transportation costs decreased to $2.59/boe in Q1 2018 from $5.21/boe for Q1 2017.

The decrease in natural gas transportation in Q1 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 decrease in oil and NGLs transportation for the three months ended March 31, 2018 was the result of different sales points and sales and transportation contracts for new production in Doe/Mica in 2018.

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. These transactions occurred in Q1 2017 when the Company had more available pipeline capacity than it used. In Q1 2018, the Company used more of its pipeline capacity as production volumes increased significantly from the comparative quarter. Net transportation and marketing expenses also deduct the marketing revenue the Company generates from the premium received on assigning unutilized firm transportation.

OPERATING NETBACK	**Three Months Ended March 31**		
	2018	2017	% Change
Oil and NGLs ($/bbl)			
Revenue	**62.08**	57.81	7
Royalties	**-**	(3.46)	(100)
Net operating expenses	**(6.32)**	(11.75)	(46)
Net transportation and marketing expenses	**(2.55)**	(3.73)	(32)
Operating netback	**53.21**	38.87	37
Natural gas ($/mcf)			
Revenue	**2.46**	2.85	(14)
Royalties	**-**	(0.15)	(100)
Net operating expenses	**(0.78)**	(1.08)	(28)
Net transportation and marketing expenses	**(0.43)**	(0.96)	(55)
Operating netback	**1.25**	0.66	89
Combined ($/boe)			
Revenue	**27.71**	28.26	(2)
Royalties	**-**	(1.59)	(100)
Net operating expenses	**(5.14)**	(7.93)	(35)
Net transportation and marketing expenses	**(2.59)**	(5.21)	(50)
Operating netback	**19.98**	13.53	48

During the first quarter of 2018, Leucrotta generated an operating netback of $19.98/boe, up 48% from $13.53/boe in the first quarter of 2017. The increase was mainly due to lower net operating and net transportation expenses per boe and royalty credits from BC's IRCP.

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

	Three Months Ended March 31		
($/boe)	**2018**	2017	% Change
Operating netback	**19.98**	13.53	48
Depletion and depreciation	**(9.37)**	(10.38)	(10)
General and administrative expenses	**(3.23)**	(6.40)	(50)
Share based compensation	**(0.72)**	(2.24)	(68)
Finance expense	**(0.16)**	(0.23)	(30)
Finance income	**0.26**	0.53	(51)
Net earnings (loss) (GAAP)	**6.76**	(5.19)	230

DEPLETION AND DEPRECIATION	**Three Months Ended March 31**		
	2018	2017	% Change
Depletion and depreciation ($000s)	**3,524**	1,756	101
Depletion and depreciation ($/boe)	**9.37**	10.38	(10)

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 ended March 31, 2018 was $9.37/boe compared to $10.38/boe for the comparative period in 2017. The decrease in 2018 was the result of successful drilling results adding proved plus probable reserves to the Company's reserve base at Mica and Doe.

GENERAL AND ADMINISTRATIVE	**Three Months Ended March 31**		
($000s)	**2018**	2017	% Change
G&A expenses (gross)	**1,394**	1,339	4
G&A capitalized	**(178)**	(247)	(28)
G&A recoveries	**(1)**	(10)	(90)
G&A expenses (net)	**1,215**	1,082	12
G&A expenses ($/boe)	**3.23**	6.40	(50)

General and administrative ("G&A") expenses were $3.23/boe for the first quarter of 2018 compared to $6.40/boe for the first quarter of 2017. G&A expenses in Q1 2018 were consistent with the comparative quarter in 2017 but decreased substantially on a per boe basis due to increased production in Q1 2018.

SHARE BASED COMPENSATION

	Three Months Ended March 31		
	2018	2017	% Change
Share based compensation ($000s)	**271**	380	(29)
Share based compensation ($/boe)	**0.72**	2.24	(68)

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 performance warrants was determined based on a Monte Carlo simulation and the fair value of stock options and purchase warrants was measured based on the Black-Scholes-Merton option-pricing model.

Share based compensation expense decreased to $0.3 million for the first quarter of 2018 from $0.4 million for the comparative quarter in 2017. The decrease is mainly due to using the graded (accelerated) amortization method whereby more expense is recognized earlier in the stock options and warrants expected life. On a per boe basis, the expense decreased in Q1 2018 from Q1 2017 due to both the lower expense and the increased production during Q1 2018 from new wells. During the quarter ended March 31, 2018, 25 thousand (March 31, 2017 - nil) stock options were granted.

FINANCE EXPENSE

	Three Months Ended March 31		
($000s)	**2018**	2017	% Change
Interest expense	**14**	2	600
Accretion of decommissioning obligations	**46**	38	21
Finance expense	**60**	40	50
Finance expense ($/boe)	**0.16**	0.23	(30)

Interest expense increased during the three months ended March 31, 2018 compared to the same period in 2017 due to the increase of the Company's undrawn credit facility in Q2 2017 which has increased the standby fees charged.

Accretion expense has increased for the three months ended March 31, 2018 compared to the same period in 2017 due to drilling activity adding more wells.

FINANCE INCOME

Finance income relates to interest earned on cash in the bank. Finance income totaled $0.1 million for the first quarter of 2018, consistent to $0.1 million in the comparative quarter in 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.

Estimated tax pools at March 31, 2018 total approximately $309.4 million (December 31, 2017 - $304.4 million).

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 March 31		
($000s)	**2018**	2017	% Change
Cash flow from operating activities	**5,931**	311	1,807
Add back:			
Change in non-cash working capital	**456**	985	(54)
Adjusted funds flow (non-GAAP)	**6,387**	1,296	393

Adjusted funds flow for the first quarter of 2018 was $6.4 million ($0.03 per basic and diluted share) compared to $1.3 million ($0.01 per basic and diluted share) for the comparative quarter in 2017. The increase was mainly due to a 122% growth in production from the successful drilling at Doe/Mica and reduced net operating expenses, net transportation expenses and royalties on a per boe basis.

Cash flow from operations increased for the three months ended March 31, 2018 to $5.9 million ($0.03 per basic and diluted share) from $0.3 million ($nil per basic and diluted share) for the comparative period in 2017. Consistent with adjusted funds flow, the increase was mainly due to the increased production from successful drilling at Doe/Mica and reduced net operating expenses, net transportation expenses and royalties on a per boe basis. 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 EARNINGS (LOSS)

Net earnings for the three months ended March 31, 2018 was $2.5 million ($0.01 per basic and diluted share) compared to a net loss of $0.9 million ($0.01 per basic and diluted share) for the comparative period in 2017.

The increase in net earnings was mainly the result of increased production from successful drilling at Doe/Mica over the past two years. Net operating expenses, net transportation expenses, royalties, G&A expenses, depletion and depreciation, and share based compensation are all trending lower on a per boe basis from prior quarters.

CAPITAL EXPENDITURES	**Three Months Ended March 31**		
($000s)	**2018**	2017	% Change
Property acquisitions	**-**	3,635	(100)
Land	**837**	234	258
Drilling, completions, and workovers	**8,108**	5,291	53
Equipment	**2,364**	8,903	(73)
Geological and geophysical	**126**	455	(72)
Office equipment	**25**	-	100
Total expenditures	**11,460**	18,518	(38)

During the first quarter of 2018 the Company drilled three Lower Montney delineation wells which are expected to be completed in the second half of 2018. One well was drilled in Alberta and two wells were drilled at Mica, BC (one drilled north of the Peace River). The Company also tied-in its Mica 12-06 light oil Montney well which commenced production during the quarter.

During the first quarter of 2017 the Company completed its Mica 12-06 well drilled in Q4 2016 and drilled an offset well to Mica 8-22 awaiting completion in Q2 2017. The Company completed its infrastructure project to tie-in four previously drilled wells in Doe/Mica (8-18, 8-22, A13-19, and A4-19). Included in capital expenditures was a $3.6 million non-refundable deposit on the $36.0 million land acquisition that closed in May 2017. This acquisition was of certain lands located within the Company's core Doe/Mica area. There were no reserves attached to these lands which are all located adjacent to existing Doe/Mica lands of the Company.

LIQUIDITY AND CAPITAL RESOURCES

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

($000s)	**March 31, 2018**	December 31, 2017	% Change
Current assets	**20,826**	29,224	(29)
Less:			
Current liabilities	**(7,213)**	(10,564)	(32)
Working capital	**13,613**	18,660	(27)

At March 31, 2018, the Company had working capital of $13.6 million and $nil had been drawn on the revolving 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 March 31, 2018, the Company had outstanding letters of guarantee of $2.8 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 November 30, 2018.

The Company has $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 $5.9 million of securities of Leucrotta common shares and a margin payable of $1.0 million. The cross-guarantee is not intended to be long-tem 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 March 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 March 31, 2018:

($000s)	**Total**	**Less than One Year**	**One to Three Years**	**After Three Years**
Accounts payable and accrued liabilities	7,213	7,213	-	-
Decommissioning obligations	9,212	-	-	9,212
Office leases	1,168	341	640	187
Firm transportation agreements	17,867	5,518	12,349	-
Total contractual obligations	35,460	13,072	12,989	9,399

Transportation commitments include contracts to transport natural gas and NGLs through third-party owned pipeline systems. The Company currently has commitments of 18.3 mmcf/d escalating over time to 33.3 mmcf/d.

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)	**March 31, 2018**	May 28, 2018
Voting common shares	**200,517**	200,517
Warrants	**15,141**	15,141
Stock options	**11,475**	11,475
Total	**227,133**	227,133

SUMMARY OF QUARTERLY RESULTS

	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017	Q4 2016	Q3 2016	Q2 2016
Average Daily Production								
Oil and NGLs (bbls/d)	**1,144**	1,290	857	609	514	234	300	319
Natural gas (mcf/d)	**18,216**	15,071	13,593	12,122	8,197	3,543	4,138	4,549
Combined (boe/d)	**4,180**	3,802	3,123	2,629	1,881	824	989	1,078
($000s, except per share amounts)								
Oil and natural gas sales	**10,426**	9,301	5,723	6,317	4,783	2,233	2,264	1,897
Adjusted funds flow	**6,387**	4,462	1,747	2,097	1,296	(98)	(124)	(491)
Per share - basic and diluted	**0.03**	0.02	0.01	0.01	0.01	-	-	-
Net earnings (loss)	**2,546**	(5,072)	(1,549)	(723)	(878)	(1,657)	(4,994)	(2,758)
Per share - basic and diluted	**0.01**	(0.03)	(0.01)	-	(0.01)	(0.01)	(0.03)	(0.02)

Production, oil and natural gas sales and adjusted funds flow increased significantly in each quarter of 2017 and 2018 from the successful drilling at Doe/Mica in the Montney formation. The increased loss in Q3 2016 from Q2 2016 was the result of a loss on the sale of certain gas plant equipment of $2.6 million. 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.

SIGNIFICANT ACCOUNTING POLICIES

All accounting policies are consistent with those of the previous financial year with the exception of those noted below. Refer to note 3 of the audited financial statements for the year ended December 31, 2017 for the Company's significant accounting policies.

(a) Changes in accounting policies

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 condensed interim 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, Revenues from Contracts with Customers

The Company adopted IFRS 15 "Revenue from Contracts with Customers" ("IFRS 15") effective January 1, 2018. IFRS 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 condensed interim 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 12 of the condensed interim financial statements.

The Company earns revenue from its production and sale of oil, natural gas and 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.

(b) New standards and interpretations not yet adopted

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. Earlier application is permitted for entities that apply IFRS 15 at or before the date of initial adoption of IFRS 16. 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 Company intends to adopt IFRS 16 in its financial statements for the annual period beginning on January 1, 2019. The Company is currently identifying contracts that will fall into the scope of the new standard and is evaluating the impact it will have on the financial statements.

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 audited financial statements for the year ended December 31, 2017 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 March 31, 2018 was $nil.

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 March 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 two 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 March 31, 2018, $3.4 million (93%) of the Company's outstanding accounts receivable were current and $0.1 million (2%) were outstanding for more than 90 days. During the period ended March 31, 2018, the Company did not deem any outstanding accounts receivable to be uncollectable (March 31, 2017 - $nil).

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 $13.6 million including $15.9 million of cash. 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.

Leucrotta Exploration Inc.
Condensed Statements of Financial Position
(unaudited)

($000s)	Note	March 31 2018	December 31 2017
Assets			
Current assets			
Cash and cash equivalents		**15,887**	23,747
Restricted cash		**1,000**	1,000
Accounts receivable		**3,645**	4,104
Prepaid expenses and deposits		**294**	373
		20,826	29,224
Property, plant, and equipment	(4)	**156,110**	156,395
Exploration and evaluation assets	(5)	**136,169**	127,422
		292,279	283,817
		313,105	313,041
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		**7,213**	10,564
Decommissioning obligations	(7)	**9,212**	8,718
		16,425	19,282
Shareholders' Equity			
Shareholders' capital	(8)	**288,824**	288,787
Contributed surplus		**14,736**	14,398
Deficit		**(6,880)**	(9,426)
		296,680	293,759
		313,105	313,041
Commitments	(14)		

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

Leucrotta Exploration Inc.
Condensed Statements of Operations and Comprehensive Earnings (Loss)
(unaudited)

		Three Months Ended March 31	
($000s, except per share amounts)	**Note**	**2018**	2017
Revenue			
Oil and natural gas sales	(12)	**10,426**	4,783
Processing and marketing	(12)	**398**	1,239
Royalties	(12)	**-**	(269)
		10,824	5,753
Expenses			
Operating		**2,178**	1,342
Transportation and marketing	(13)	**1,128**	2,121
Depletion and depreciation	(4)	**3,524**	1,756
General and administrative		**1,215**	1,082
Share based compensation	(9)	**271**	380
Finance income		**(98)**	(90)
Finance expense		**60**	40
		8,278	6,631
Net earnings (loss) and comprehensive earnings (loss)		**2,546**	(878)
Net earnings (loss) per share			
Basic and diluted	(10)	**0.01**	(0.01)

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

Leucrotta Exploration Inc.
Condensed Statements of Shareholders' Equity
(unaudited)

($000s)	Shareholders' Capital	Contributed Surplus	Deficit	Total Equity
Balance, December 31, 2016	213,875	12,493	(1,204)	225,164
Net loss	-	-	(878)	(878)
Exercise of warrants and stock options	67	(19)	-	48
Share based compensation	-	481	-	481
Balance, March 31, 2017	213,942	12,955	(2,082)	224,815
Balance, December 31, 2017	288,787	14,398	(9,426)	293,759
Net earnings	-	-	2,546	2,546
Exercise of stock options	37	(11)	-	26
Share based compensation	-	349	-	349
Balance, March 31, 2018	288,824	14,736	(6,880)	296,680

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

Leucrotta Exploration Inc.
Condensed Statements of Cash Flows
(unaudited)

		Three Months ended March 31	
($000s)	Note	**2018**	2017
Operating Activities			
Net earnings (loss)		**2,546**	(878)
Depletion and depreciation	(4)	**3,524**	1,756
Share based compensation	(9)	**271**	380
Finance expense		**60**	40
Interest paid		**(14)**	(2)
Change in non-cash working capital	(11)	**(456)**	(985)
		5,931	311
Financing Activities			
Exercise of warrants and stock options		**26**	48
Investing Activities			
Capital expenditures - property, plant, and equipment	(4)	**(2,777)**	(11,382)
Capital expenditures - exploration and evaluation assets	(5)	**(8,683)**	(3,501)
Property acquisitions		**-**	(3,635)
Change in non-cash working capital	(11)	**(2,357)**	(873)
		(13,817)	(19,391)
Change in cash and cash equivalents		**(7,860)**	(19,032)
Cash and cash equivalents, beginning of period		**23,747**	32,997
Cash and cash equivalents, end of period		**15,887**	13,965

The accompanying notes are an integral part of these condensed interim 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 condensed interim financial statements reflect only the Company's proportionate interest in such activities.

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

2. BASIS OF PRESENTATION

(a) Statement of compliance

These condensed interim financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") applicable to the preparation of interim financial statements, as prescribed by IAS 34, Interim Financial Reporting. The condensed interim financial statements do not include all of the information and disclosure required in annual financial statements and should be read in conjunction with the audited financial statements and related notes for the year ended December 31, 2017.

Certain prior period amounts have been reclassified to conform to the current presentation.

The condensed interim financial statements were authorized for issuance by the Board of Directors on May 28, 2018.

(b) Basis of measurement

The condensed interim financial statements have been prepared on the historical cost basis, except as detailed in the accounting policies disclosed in note 3 of the Company's audited financial statements for the year ended December 31, 2017.

(c) Functional and presentation currency

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

(d) Use of estimates and judgments

The preparation of the condensed interim 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 condensed interim 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 interim financial statements. Accordingly, actual results may differ from the estimated amounts as future confirming events occur. The significant estimates and judgments made by management in the preparation of these condensed interim financial statements were consistent with those applied to the financial statements as at and for the year ended December 31, 2017.

3. SIGNIFICANT ACCOUNTING POLICIES

Except for the changes described below, the condensed interim financial statements have been prepared following the same accounting policies as the annual financial statements for the year ended December 31, 2017. The accounting policies have been applied consistently by the Company to all periods presented in these condensed interim financial statements.

(a) Changes in accounting policies

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 condensed interim 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, Revenues from Contracts with Customers

The Company adopted IFRS 15 "Revenue from Contracts with Customers" ("IFRS 15") effective January 1, 2018. IFRS 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 condensed interim 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 12 of these condensed interim financial statements.

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.

(b) New standards and interpretations not yet adopted

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. Earlier application is permitted for entities that apply IFRS 15 at or before the date of initial adoption of IFRS 16. 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 Company intends to adopt IFRS 16 in its financial statements for the annual period beginning on January 1, 2019. The Company is currently identifying contracts that will fall into the scope of the new standard and is evaluating the impact it will have on the financial statements.

4. 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	**2,777**
Change in decommissioning obligations	**448**
Capitalized share based compensation	**14**
Balance, March 31, 2018	**195,317**

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
Depletion and depreciation	**3,524**
Balance, March 31, 2018	**39,207**

Net Book Value	Total
December 31, 2017	156,395
March 31, 2018	**156,110**

During the three months ended March 31, 2018, $0.1 million (March 31, 2017 - $0.2 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 three months ended March 31, 2018 included an estimated $166.1 million (March 31, 2017 - $81.7 million) for future development costs associated with proved plus probable undeveloped reserves and excluded approximately $3.7 million (March 31, 2017 - $3.2 million) for the estimated salvage value of production equipment and facilities.

5. 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	**8,683**
Capitalized share based compensation	**64**
Balance, March 31, 2018	**136,169**

Exploration and evaluation 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 three months ended March 31, 2018, $0.1 million (March 31, 2017 - $nil) of directly attributable general and administrative costs were capitalized as expenditures on exploration and evaluation assets.

6. 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 March 31, 2018, $nil had been drawn on the revolving credit facility. At March 31, 2018, the Company had outstanding letters of guarantee of $2.8 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 November 30, 2018.

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 March 31, 2018.

7. 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 32 years. At March 31, 2018, a risk-free rate of 2.22% (December 31, 2017 – 2.15%) was used to calculate the net present value of the decommissioning obligations.

	Three Months Ended March 31, 2018	Year Ended December 31, 2017
Balance, beginning of period	**8,718**	6,820
Provisions incurred	**409**	1,604
Provisions settled	**-**	(296)
Dispositions	**-**	(239)
Revisions in estimated cash flows	**180**	435
Revisions due to change of discount rates	**(141)**	232
Accretion	**46**	162
Balance, end of period	**9,212**	8,718

8. 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	**20**	**37**
Balance, March 31, 2018	**200,517**	**288,824**

9. 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 March 31, 2018, 11.5 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	**(20)**	**1.29**
Balance, March 31, 2018	**11,475**	**1.25**

During the three months ended March 31, 2018, the Company recognized $0.3 million (March 31, 2017 - $0.2 million) of share based compensation related to the stock options. At March 31, 2018 there was $1.4 million remaining as unrecognized share based compensation related to the stock options.

Performance Warrants

	Number	Exercise Price
Balance, December 31, 2016	7,500	1.70
Exercised	(9)	1.70
Balance, December 31, 2017 and March 31, 2018	**7,491**	**1.70**
Exercisable, March 31, 2018	**4,491**	**1.70**

During the three months ended March 31, 2018, the Company recognized $nil (March 31, 2017 - $0.1 million) of share based compensation related to the performance warrants. At March 31, 2018 there was $nil remaining as unrecognized share based compensation related to the performance warrants.

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, 2019 vesting equally over three years.

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

During the three months ended March 31, 2018, the Company recognized $nil (March 31, 2017 - $0.2 million) of share based compensation related to the purchase warrants. At March 31, 2018 there was $nil remaining as unrecognized share based compensation related to the purchase warrants.

Share based compensation

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:

	Three Months Ended March 31	
	2018	2017
Risk-free interest rate (%)	**1.9**	-
Expected life (years)	**4.0**	-
Expected volatility (%)	**51.3**	-
Expected dividend yield (%)	**-**	-
Forfeiture rate (%)	**0.2**	-
Weighted average fair value of options granted ($ per option)	**0.71**	-

10. PER SHARE AMOUNTS

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

	Three Months Ended March 31	
	2018	2017
Weighted average number of shares - basic	**200,516**	165,239
Dilutive effect of share based compensation plans	**2,791**	-
Weighted average number of shares - diluted	**203,307**	165,239

For the three months ended March 31, 2018, 2.7 million stock options (March 31, 2017 - 8.9 million), 7.7 million purchase warrants (March 31, 2017 - 7.7 million) and 7.5 million performance warrants (March 31, 2017 - 7.5 million) were anti-dilutive and were not included in the diluted net earnings (loss) per share calculation.

11. SUPPLEMENTAL CASH FLOW INFORMATION

	Three Months Ended March 31	
	2018	2017
Accounts receivable	**459**	(1,583)
Prepaid expenses and deposits	**79**	26
Accounts payable and accrued liabilities	**(3,351)**	(301)
Change in non-cash working capital	**(2,813)**	(1,858)
Relating to:		
Investing	**(2,357)**	(873)
Operating	**(456)**	(985)
Change in non-cash working capital	**(2,813)**	(1,858)

12. 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:

	Three Months Ended March 31	
	2018	2017
Oil and condensate	**5,318**	2,386
Other natural gas liquids	**1,075**	291
Natural gas	**4,033**	2,106
Oil and natural gas sales	**10,426**	4,783

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:

	Three Months Ended March 31	
	2018	2017
Natural gas production sales	**3,233**	1,276
Transportation revenue	**800**	830
Natural gas sales	**4,033**	2,106

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

	Three Months Ended March 31	
	2018	2017
Sale of purchased natural gas	**-**	1,239
Processing revenue	**246**	-
Marketing revenue	**152**	-
Processing and marketing revenue	**398**	1,239

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 13).

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, two customers represented combined sales of 96% for the period ended March 31, 2018 (March 31, 2017 – 98%).

During the three months ended March 31, 2018, the Company began receiving credits to offset royalties from British Columbia Government's Infrastructure Royalty Credit Program resulting from infrastructure built in 2017 and wells drilled and tied-into the related infrastructure. The Company realized credits of $0.8 million in the period to offset royalties payable.

13. TRANSPORTATION AND MARKETING EXPENSES

	Three Months Ended March 31	
	2018	2017
Pipeline tariffs from firm transportation agreements	**1,128**	1,035
Purchased natural gas	**-**	1,086
Transportation and marketing expenses	**1,128**	2,121

14. COMMITMENTS

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

	2018	**2019**	**2020**	**2021**	**2022**	**Thereafter**	**Total**
Office leases	261	320	320	267	-	-	1,168
Firm transportation agreements	3,544	7,894	6,429	-	-	-	17,867
	3,805	8,214	6,749	267	-	-	19,035

Transportation commitments include contracts to transport natural gas and NGLs through third-party owned pipeline systems. The Company currently has commitments of 18.3 mmcf/d escalating over time to 33.3 mmcf/d.

CORPORATE
INFORMATION

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FORWARD-LOOKING STATEMENTS

This Interim Report may contain forward-looking information that involves a number of risks and uncertainties that could cause actual results to differ materially from those anticipated. For this purpose, any statements herein that are not statements of historical fact may be deemed to be forward-looking statements. Such risks and uncertainties include, but are not limited to: risks associated with the oil and gas industry (e.g. operational risks in exploration, development and production; changes and/or delays in the development of capital assets; uncertainty of reserve estimates; uncertainty of estimates and projections relating to production and costs; commodity price fluctuations; environmental risks; and industry competition).