LEUCROTTA EXPLORATION INC.

Q3 2017 RESULTS

FINANCIAL AND OPERATING RESULTS FOR THE THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2017

HIGHLIGHTS

- Increased production 216% to 3,123 boe/d in Q3 2017 from 989 boe/d in Q3 2016 (increased 19% from 2,629 boe/d in Q2 2017).
- Increased funds from operations 1,509% to $1.7 million in Q3 2017 from funds used in operations of $0.1 million in Q3 2016.
- Tied-in Mica 8-4 and Mica A8-22 Lower Montney Oil wells.
- Drilled two Lower Montney wells at Doe/Mica awaiting completions/results.

FINANCIAL RESULTS	THREE MONTHS ENDED SEPTEMBER 30			NINE MONTHS ENDED SEPTEMBER 30		
($000s, except per share amounts)	**2017**	2016	% Change	**2017**	2016	% Change
OIL AND NATURAL GAS SALES	**5,908**	2,309	156	**17,258**	6,563	163
FUNDS FROM (USED IN) OPERATIONS[(1)]	**1,747**	(124)	1,509	**5,140**	(898)	672
Per share - basic and diluted	**0.01**	-	100	**0.03**	(0.01)	400
NET LOSS	**(1,549)**	(4,994)	(69)	**(3,150)**	(10,525)	(70)
Per share - basic and diluted	**(0.01)**	(0.03)	(67)	**(0.02)**	(0.06)	(67)
CAPITAL EXPENDITURES AND ACQUISITIONS	**16,316**	5,775	183	**77,644**	10,856	615
PROCEEDS FROM SALE OF EQUIPMENT	**-**	4,000	(100)	**-**	4,000	(100)
WORKING CAPITAL				**29,248**	37,879	(23)
COMMON SHARES OUTSTANDING (000S)						
Weighted average - basic and diluted	**200,479**	165,227	21	**185,633**	165,227	12
End of period - basic				**200,479**	165,227	21
End of period - diluted				**227,108**	189,297	20

(1) Funds from (used in) operations and funds from (used in) operations 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 Funds from (used in) Operations section in the MD&A for a reconciliation from cash flow from operating activities.

OPERATING RESULTS [1]	Three Months Ended September 30			Nine Months Ended September 30		
	2017	2016	% Change	**2017**	2016	% Change
Daily production						
Oil and NGLs (bbls/d)	**857**	300	186	**661**	345	92
Natural gas (mcf/d)	**13,593**	4,138	228	**11,324**	4,588	147
Oil equivalent (boe/d)	**3,123**	989	216	**2,549**	1,110	130
Revenue						
Oil and NGLs ($/bbl)	**50.97**	48.28	6	**53.71**	43.08	25
Natural gas ($/mcf)	**1.51**	2.57	(41)	**2.45**	2.00	23
Oil equivalent ($/boe)	**20.56**	25.37	(19)	**24.80**	21.67	14
Royalties						
Oil and NGLs ($/bbl)	**5.66**	5.88	(4)	**5.98**	4.16	44
Natural gas ($/mcf)	**0.03**	0.10	(70)	**0.07**	0.03	133
Oil equivalent ($/boe)	**1.67**	2.20	(24)	**1.88**	1.42	32
Production expenses						
Oil and NGLs ($/bbl)	**7.16**	18.92	(62)	**8.40**	16.76	(50)
Natural gas ($/mcf)	**1.10**	1.29	(15)	**1.14**	1.14	-
Oil equivalent ($/boe)	**6.75**	11.12	(39)	**7.24**	9.94	(27)
Transportation expenses						
Oil and NGLs ($/bbl)	**2.22**	6.02	(63)	**3.07**	5.06	(39)
Natural gas ($/mcf)	**0.54**	0.44	23	**0.71**	0.43	65
Oil equivalent ($/boe)	**2.94**	3.65	(19)	**3.96**	3.37	18
Operating netback [2]						
Oil and NGLs ($/bbl)	**35.93**	17.46	106	**36.26**	17.10	112
Natural gas ($/mcf)	**(0.16)**	0.74	(122)	**0.53**	0.40	33
Oil equivalent ($/boe)	**9.20**	8.40	10	**11.72**	6.94	69
Depletion and depreciation ($/boe)	**(9.93)**	(15.46)	(36)	**(10.05)**	(13.07)	(23)
General and administrative expenses ($/boe)	**(3.58)**	(10.90)	(67)	**(4.76)**	(11.11)	(57)
Share based compensation ($/boe)	**(1.41)**	(9.53)	(85)	**(1.71)**	(9.93)	(83)
Finance expenses ($/boe)	**(0.21)**	(0.52)	(60)	**(0.25)**	(0.41)	(39)
Finance income ($/boe)	**0.54**	1.31	(59)	**0.51**	1.30	(61)
Loss on sale of assets ($/boe)	**-**	(28.15)	(100)	**-**	(8.46)	(100)
Net loss ($/boe)	**(5.39)**	(54.85)	(90)	**(4.54)**	(34.74)	(87)

(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) Operating netback does 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.

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

November 27, 2017

The MD&A should be read in conjunction with the unaudited condensed interim financial statements and related notes for the three and nine months ended September 30, 2017 and the audited financial statements and MD&A for the year ended December 31, 2016. 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.

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 "funds from (used in) operations", "funds from (used in) operations per share", and "operating netback" 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 funds from (used in) operations 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 to repay debt. Funds from (used in) operations 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 funds from (used in) operations per share whereby amounts per share are calculated using weighted average shares outstanding, consistent with the calculation of net loss per share. Funds from (used in) operations is reconciled from cash flow from operating activities under the heading "Funds from (used in) Operations".

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, production expenses, and transportation 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".

UPDATE

In Q3 2017, Leucrotta focused its efforts on refining the completion techniques for the Lower Montney. The first well with increased frac intensity was the A8-22 well that had 41 frac stages versus previous wells with 28 frac stages. As previously released, this well had IP90(1) production of 838 boe/d that was 61% above Leucrotta's type curve(1) of 521 boe/d for the area and continues to produce significantly above the type curve. Leucrotta has continued to increase the frac intensity in subsequent wells that have recently been completed with 50 frac stages over the same one mile horizontal lateral length.

Leucrotta will continue to monitor the production of the wells to determine the effect of the increased frac intensity over a longer term period and its effect on the ultimate recoveries of the wells. Future wells will be focused primarily on the oil window of the Lower Montney and will be a combination of delineation and higher intensity frac wells. We anticipate the extent of the 2018 capital program will be released in early 2018.

Production continues to increase as new wells are placed on production and is projected to average 3,600 boe/d (30% oil and liquids) for Q4 2017. Leucrotta's gathering system is currently running higher than optimal pressures with several wells having to flow against significant back pressure. While future opportunities exist to optimize the production through debottlenecking and reducing wellhead operating pressures, Leucrotta has chosen to focus its near term capital on drilling and completion.

At the end of Q3 2017, Leucrotta had approximately $29 million of working capital, no debt, and a $20 million undrawn bank credit facility. Leucrotta estimates that it will have approximately $18 million of working capital, no debt and an undrawn bank credit facility of $20 million at the end of 2017.

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

(1) See "Production Rates" and "Type Curves" sections for more details.

SUMMARY OF FINANCIAL RESULTS

($000s, except per share amounts)	Three Months Ended September 30			Nine Months Ended September 30		
	2017	2016	% Change	**2017**	2016	% Change
Oil and natural gas sales	**5,908**	2,309	156	**17,258**	6,563	163
Funds from (used in) operations	**1,747**	(124)	1,509	**5,140**	(898)	672
Per share - basic and diluted	**0.01**	-	100	**0.03**	(0.01)	400
Net loss	**(1,549)**	(4,994)	(69)	**(3,150)**	(10,525)	(70)
Per share - basic and diluted	**(0.01)**	(0.03)	(67)	**(0.02)**	(0.06)	(67)
Total assets				**319,383**	240,125	33
Total long-term liabilities				**9,308**	7,722	21
Working capital				**29,248**	37,879	(23)

The Company experienced a substantial increase in oil and natural gas sales and funds from operations and a decreased net loss for the first nine months of 2017 compared to the same period in 2016. This was mainly due to significant production growth from successful drilling at Doe/Mica in the Montney formation during 2016 and 2017 and an overall 14% increase in oil, NGLs, and natural gas commodity prices. The decrease in working capital is mainly the net result from capital expenditures of $11.7 million during the last quarter of 2016 and $77.6 million during the first nine months of 2017 (see “Capital Expenditures”) partially offset by the $80.0 million financing in Q2 2017 (see “Liquidity and Capital Resources”).

PRODUCTION	Three Months Ended September 30			Nine Months Ended September 30		
	2017	2016	% Change	**2017**	2016	% Change
Average Daily Production						
Oil and NGLs (bbls/d)	**857**	300	186	**661**	345	92
Natural gas (mcf/d)	**13,593**	4,138	228	**11,324**	4,588	147
Combined (boe/d)	**3,123**	989	216	**2,549**	1,110	130

Daily production increased to 3,123 boe/d and 2,549 boe/d for the three and nine months ended September 30, 2017, respectively, from 989 boe/d and 1,110 boe/d for the comparative periods in 2016. The increase in production was due to the tie-in of five previously drilled wells in Doe/Mica (8-18, 8-22, 8-4, A13-19, and A4-19) and the drill and tie-in of Mica A8-22 in 2017.

Leucrotta’s production profile for the third quarter of 2017 saw a slight decrease in liquids weighting over the comparative quarter in 2016. The Q3 2017 weighting was 73% natural gas (Q3 2016 - 70%) and 27% oil and NGLs (Q3 2016 - 30%). The first nine months of 2016 had a higher liquids weighting than 2017 due to new flush production from new light oil wells at Mica and Stoddart on a much smaller production base.

REVENUE	Three Months Ended September 30			Nine Months Ended September 30		
($000s)	**2017**	2016	% Change	**2017**	2016	% Change
Oil and NGLs	**4,019**	1,332	202	**9,698**	4,057	139
Natural gas	**1,889**	977	93	**7,560**	2,506	202
Total	**5,908**	2,309	156	**17,258**	6,563	163
Average Sales Price						
Oil and NGLs ($/bbl)	**50.97**	48.28	6	**53.71**	43.08	25
Natural gas ($/mcf)	**1.51**	2.57	(41)	**2.45**	2.00	23
Combined ($/boe)	**20.56**	25.37	(19)	**24.80**	21.67	14

Revenue totaled $5.9 million and $17.3 million for the three and nine months ended September 30, 2017, respectively, compared to $2.3 million and $6.6 million for the comparative periods in 2016. This was mainly due to significant production growth from successful drilling at Doe/Mica in the Montney formation during 2016 and 2017 and an overall 14% increase in oil, NGLs, and natural gas commodity prices.

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

Commodity Pricing	Three Months Ended September 30			Nine Months Ended September 30		
	2017	2016	% Change	**2017**	2016	% Change
Oil and NGLs						
Corporate price ($CDN/bbl)	**50.97**	48.28	6	**53.71**	43.08	25
Canadian light sweet ($CDN/bbl)	**57.15**	54.19	5	**60.57**	49.44	23
West Texas Intermediate ("WTI") ($US/bbl)	**48.20**	44.94	7	**49.47**	40.84	21
Natural gas						
Corporate price ($CDN/mcf)	**1.51**	2.57	(41)	**2.45**	2.00	23
AECO price ($CDN/mcf)	**1.61**	2.36	(32)	**2.36**	1.77	33
Exchange rate						
$US/$CAD exchange rate	**0.7981**	0.7668	4	**0.7660**	0.7564	1

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 89.2% and 88.7% of Canadian light sweet prices for the three and nine months ended September 30, 2017, respectively, consistent with the comparative periods in 2016 of 89.1% and 87.1%.

Corporate average natural gas prices were 93.8% and 103.8% of AECO price for the three and nine months ended September 30, 2017, respectively, down from 108.9% and 113.0% for the comparative periods in 2016.

Leucrotta's liquids mix during the third quarter of 2017 was approximately 76% oil, condensate and pentanes, 8% butane and 16% propane (Q3 2016 - 82% oil, condensate and pentanes, 7% butane and 11% 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 September 30			Nine Months Ended September 30		
($000s)	**2017**	2016	% Change	**2017**	2016	% Change
Oil and NGLs	**446**	163	174	**1,079**	392	175
Natural gas	**33**	37	(11)	**227**	39	482
Total	**479**	200	140	**1,306**	431	203
Average Royalty Rate (% of sales)						
Oil and NGLs	**11.1**	12.2	(9)	**11.1**	9.7	14
Natural gas	**1.7**	3.8	(55)	**3.0**	1.6	88
Combined	**8.1**	8.7	(7)	**7.6**	6.6	15

The Company pays royalties to provincial governments (Crown), freeholders, which may be individuals or companies, and other oil and gas companies that own surface or mineral rights. 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.

For the third quarter of 2017, oil, NGLs, and natural gas royalties totaled $0.5 million (8.1% of revenue) compared to $0.2 million (8.7% of revenue) for the comparative quarter in 2016. Year-to-date in 2017, oil, NGLs, and natural gas royalties totaled $1.3 million (7.6% of revenue) compared to $0.4 million (6.6% of revenue) for the comparative period in 2016.

Oil and NGLs royalties remained consistent at 11.1% for the three and nine months ended September 30, 2017, compared to 12.2% and 9.7% in the comparative periods in 2016.

Natural gas royalties have decreased to 1.7% for the three months ended September 30, 2017 compared to 3.8% for the comparative period in 2016 due to weaker natural gas prices in Q3 2017. Year-to-date, natural gas royalties have increased to 3.0% in 2017 from 1.6% in 2016 due to higher natural gas prices for the first nine months in 2017. Natural gas royalties for the Company remain low due to weak natural gas prices and a number of its natural gas wells having deep gas royalty credits.

The Company expects to benefit in the future from BC's Infrastructure Royalty Credit Program (IRCP) in the form of reduced royalties as 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.

PRODUCTION EXPENSES	Three Months Ended September 30			Nine Months Ended September 30		
($000s)	**2017**	2016	% Change	**2017**	2016	% Change
Oil and NGLs	**564**	521	8	**1,517**	1,578	(4)
Natural gas	**1,374**	491	180	**3,521**	1,432	146
Total	**1,938**	1,012	92	**5,038**	3,010	67
Average expense						
Oil and NGLs ($/bbl)	**7.16**	18.92	(62)	**8.40**	16.76	(50)
Natural gas ($/mcf)	**1.10**	1.29	(15)	**1.14**	1.14	-
Combined ($/boe)	**6.75**	11.12	(39)	**7.24**	9.94	(27)

Per unit production expenses decreased to $6.75/boe and $7.24/boe for the three and nine months ended September 30, 2017, respectively, from $11.12/boe and $9.94/boe in the comparative periods in 2016. 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, thereby spreading the fixed gas plant expenses over a larger production base.

TRANSPORTATION EXPENSES	Three Months Ended September 30			Nine Months Ended September 30		
($000s)	**2017**	2016	% Change	**2017**	2016	% Change
Oil and NGLs	**175**	166	5	**554**	477	16
Natural gas	**671**	166	304	**2,201**	542	306
Total	**846**	332	155	**2,755**	1,019	170
Average expense						
Oil and NGLs ($/bbl)	**2.22**	6.02	(63)	**3.07**	5.06	(39)
Natural gas ($/mcf)	**0.54**	0.44	23	**0.71**	0.43	65
Combined ($/boe)	**2.94**	3.65	(19)	**3.96**	3.37	18

Transportation expenses are mainly third-party pipeline tariffs incurred to deliver production to the purchasers at main hubs. Transportation costs were $2.94/boe and $3.96/boe for the three and nine months ended September 30, 2017, respectively, compared to $3.65/boe and $3.37/boe for the comparative periods in 2016. The year-to-date increase was mainly due to unutilized firm transportation. The Company mitigates the extra firm transportation on a monthly basis by selling to other producers, however, with new wells coming on-stream during the first half of 2017, the Company kept more firm transportation but those wells were tied-in later than originally expected. This issue was rectified in Q3 2017 as the Company was able to predict timing of new wells being tied-in and therefore was able to offload more of the extra transportation to other producers.

OPERATING NETBACK	Three Months Ended September 30			Nine Months Ended September 30		
	2017	2016	% Change	**2017**	2016	% Change
Oil and NGLs ($/bbl)						
Revenue	**50.97**	48.28	6	**53.71**	43.08	25
Royalties	**(5.66)**	(5.88)	(4)	**(5.98)**	(4.16)	44
Production expenses	**(7.16)**	(18.92)	(62)	**(8.40)**	(16.76)	(50)
Transportation expenses	**(2.22)**	(6.02)	(63)	**(3.07)**	(5.06)	(39)
Operating netback	**35.93**	17.46	106	**36.26**	17.10	112
Natural gas ($/mcf)						
Revenue	**1.51**	2.57	(41)	**2.45**	2.00	23
Royalties	**(0.03)**	(0.10)	(70)	**(0.07)**	(0.03)	133
Production expenses	**(1.10)**	(1.29)	(15)	**(1.14)**	(1.14)	-
Transportation expenses	**(0.54)**	(0.44)	23	**(0.71)**	(0.43)	65
Operating netback	**(0.16)**	0.74	(122)	**0.53**	0.40	33
Combined ($/boe)						
Revenue	**20.56**	25.37	(19)	**24.80**	21.67	14
Royalties	**(1.67)**	(2.20)	(24)	**(1.88)**	(1.42)	32
Production expenses	**(6.75)**	(11.12)	(39)	**(7.24)**	(9.94)	(27)
Transportation expenses	**(2.94)**	(3.65)	(19)	**(3.96)**	(3.37)	18
Operating netback	**9.20**	8.40	10	**11.72**	6.94	69

During the three and nine months ended September 30, 2017, Leucrotta generated an operating netback of $9.20/boe and $11.72/boe, respectively, up from $8.40/boe and $6.94/boe for the comparative periods in 2016. The increase in Q3 2017 from Q3 2016 was mainly due to significantly lower production expenses per boe as well as higher oil and NGLs pricing and lower transportation and royalty costs, which were partially offset by lower natural gas prices. Year-to-date, the increase in 2017 was mainly due to substantially higher oil, NGLs, and natural gas commodity prices and lower production expenses partially offset by increased royalties and transportation expenses.

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

	Three Months Ended September 30			Nine Months Ended September 30		
($/boe)	**2017**	2016	% Change	**2017**	2016	% Change
Operating netback	**9.20**	8.40	10	**11.72**	6.94	69
Depletion and depreciation	**(9.93)**	(15.46)	(36)	**(10.05)**	(13.07)	(23)
General and administrative expenses	**(3.58)**	(10.90)	(67)	**(4.76)**	(11.11)	(57)
Share based compensation	**(1.41)**	(9.53)	(85)	**(1.71)**	(9.93)	(83)
Finance expenses	**(0.21)**	(0.52)	(60)	**(0.25)**	(0.41)	(39)
Finance income	**0.54**	1.31	(59)	**0.51**	1.30	(61)
Loss on sale of assets	**-**	(28.15)	(100)	**-**	(8.46)	(100)
Net loss (GAAP)	**(5.39)**	(54.85)	(90)	**(4.54)**	(34.74)	(87)

DEPLETION AND DEPRECIATION	Three Months Ended September 30			Nine Months Ended September 30		
	2017	2016	% Change	**2017**	2016	% Change
Depletion and depreciation ($000s)	**2,853**	1,408	103	**6,990**	3,960	77
Depletion and depreciation ($/boe)	**9.93**	15.46	(36)	**10.05**	13.07	(23)

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 and nine months ended September 30, 2017 was $9.93/boe and $10.05/boe, respectively, down from $15.46/boe and $13.07/boe for the comparative periods in 2016. The decrease in 2017 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 September 30			Nine Months Ended September 30		
($000s)	**2017**	2016	% Change	**2017**	2016	% Change
G&A expenses (gross)	**1,226**	1,109	11	**3,816**	3,606	6
G&A capitalized	**(197)**	(90)	119	**(572)**	(154)	271
G&A recoveries	**-**	(27)	(100)	**69**	(86)	(180)
G&A expenses (net)	**1,029**	992	4	**3,313**	3,366	(2)
G&A expenses ($/boe)	**3.58**	10.90	(67)	**4.76**	11.11	(57)

General and administrative expenses ("G&A") were $3.58/boe and $4.76/boe for the three and nine months ended September 30, 2017, respectively, compared to $10.90/boe and $11.11/boe for the comparative periods in 2016. G&A expenses in the first nine months of 2017 were consistent with 2016 but decreased on a per boe basis due to increased production in 2017. Also contributing to the decrease in net G&A expenses was increased capitalization in 2017 over 2016 stemming from a significant increase in capital expenditures during 2017.

SHARE BASED COMPENSATION	Three Months Ended September 30			Nine Months Ended September 30		
	2017	2016	% Change	**2017**	2016	% Change
Share based compensation ($000s)	**406**	868	(53)	**1,187**	3,007	(61)
Share based compensation ($/boe)	**1.41**	9.53	(85)	**1.71**	9.93	(83)

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 $0.4 million for the third quarter of 2017 from $0.9 million for the comparative quarter in 2016. Year-to-date, share based compensation expense decreased to $1.2 million for 2017 from $3.0 million in 2016. 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 2017 from 2016 due to both the lower expense and the increased production during 2017 from new wells. Over the twelve months prior to September 2017, no new stock options were granted and no new purchase warrants or performance warrants were granted, thus contributing to the low share based compensation expense for 2017. In September 2017, 2.6 million stock options were granted which will increase share based compensation in future periods.

FINANCE EXPENSE	Three Months Ended September 30			Nine Months Ended September 30		
($000s)	**2017**	2016	% Change	**2017**	2016	% Change
Interest expense	**24**	16	50	**64**	28	129
Accretion of decommissioning obligations	**37**	31	19	**113**	97	16
Finance expense	**61**	47	30	**177**	125	42
Finance expense ($/boe)	**0.21**	0.52	(60)	**0.25**	0.41	(39)

Interest expense increased during the first nine months of 2017 compared to 2016 due to the increase of the Company's undrawn credit facility in 2017 which has increased the standby fees charged.

Accretion expense has remained consistent with prior quarters.

FINANCE INCOME

For the three and nine months ended September 30, 2017, finance income totaled $0.2 million and $0.4 million, respectively, consistent with $0.1 million and $0.4 million for the comparative periods in 2016. Finance income relates to interest earned on cash in the bank.

DEFERRED INCOME TAXES

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

Estimated tax pools at September 30, 2017 total approximately $298.8 million (December 31, 2016 - $221.9 million).

FUNDS FROM (USED IN) OPERATIONS

The following is a reconciliation of cash flow from operating activities to funds from (used in) operations for the periods noted:

	Three Months Ended September 30			Nine Months Ended September 30		
($000s)	**2017**	2016	% Change	**2017**	2016	% Change
Cash flow from operating activities	**1,322**	1,113	19	**5,017**	617	713
Deduct:						
Change in non-cash working capital	**425**	(1,237)	134	**123**	(1,515)	108
Funds from (used in) operations (non-GAAP)	**1,747**	(124)	1,509	**5,140**	(898)	672

Funds from operations for the third quarter of 2017 was $1.7 million ($0.01 per basic and diluted share) compared to funds used in operations of $0.1 million ($nil per basic and diluted share) for the comparative quarter in 2016. Year-to-date 2017 funds from operations was $5.1 million ($0.03 per basic and diluted share) compared to funds used in operations of $0.9 million ($0.01 per basic and diluted share) for 2016. The significant increase for the three and nine months ended September 30, 2017 was mainly due to the increased production from successful drilling over the past two years. Production, transportation and G&A expenses are all trending lower on a per boe basis from prior quarters.

Cash flow from operations increased for the three and nine months ended September 30, 2017 to $1.3 million and $5.0 million, respectively, from $1.1 million and $0.6 million for the comparative periods in 2016. Consistent with funds from operations, the increase was mainly due to the increased production from successful drilling over the past two years. Cash flow from operating activities differs from funds from operations due to the inclusion of changes in non-cash working capital.

NET LOSS

Net loss has significantly decreased during the three and nine month periods ended September 30, 2017 to $1.5 million and $3.2 million, respectively, from $5.0 million and $10.5 million for the comparative periods in 2016. The decrease in the net loss was mainly due to the aforementioned production growth, decreased share based compensation and a $2.6 million loss on sale of equipment in Q3 2016.

CAPITAL EXPENDITURES	Three Months Ended September 30			Nine Months Ended September 30		
($000s)	**2017**	2016	% Change	**2017**	2016	% Change
Property acquisitions (net)	**-**	401	(100)	**35,550**	3,534	906
Land	**375**	86	336	**1,517**	659	130
Drilling, completions, and workovers	**12,700**	787	1,514	**23,185**	1,039	2,131
Equipment	**3,185**	4,278	(26)	**16,595**	5,325	212
Geological and geophysical	**56**	223	(75)	**797**	299	167
Total expenditures	**16,316**	5,775	183	**77,644**	10,856	615
Sale of gas plant equipment	**-**	4,000	(100)	**-**	4,000	(100)

During the first nine months of 2017, the Company completed its Mica 12-06 and drilled and completed an offset well to Mica 8-22 (A8-22). The Company 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). In Q3 2017, the Company drilled two more Doe/Mica wells and began completing these wells continuing into Q4 2017, in addition to drilling one exploratory well at Stoddart. 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 are no reserves attached to any of the net acquisition lands.

In the first nine months of 2016 the Company added Montney acreage adjacent to its Montney land base through both Crown land sales and private land acquisitions and began the pipeline system and infrastructure required to tie-in previously drilled wells to the Company's Doe gas plant. Other capital expenditures during that period were kept to a minimum due to the low oil and natural gas commodity prices and the Company's preference at that time to preserve its positive cash balance.

LIQUIDITY AND CAPITAL RESOURCES

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

($000s)	**September 30, 2017**	December 31, 2016	% Change
Current assets	**40,960**	35,714	15
Less:			
Current liabilities	**(11,712)**	(9,651)	21
Working capital	**29,248**	26,063	12

At September 30, 2017, the Company had working capital of $29.2 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. At September 30, 2017, $nil had been drawn on the revolving credit facility. At September 30, 2017, the Company had outstanding letters of guarantee of $1.9 million which reduce the amount that can be borrowed under the credit facility.

On April 26, 2017, the Company closed a bought-deal public financing for an aggregate of 33,333,400 common shares at a price of $2.25 per common share and 1,852,000 common shares on a flow-through basis at a price of $2.70 per flow-through common share for total gross proceeds of $80.0 million. The proceeds of the financing were used to fund the aforementioned net property acquisitions and the Company's 2017 capital program. The Company has until December 31, 2018 to incur the required Canadian exploration expenditures of $5.0 million.

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 $7.1 million of securities of Leucrotta common shares and a margin payable of $1.5 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 September 30, 2017.

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 September 30, 2017:

($000s)	**Total**	**Less than One Year**	**One to Three Years**	**After Three Years**
Accounts payable and accrued liabilities	11,712	11,712	-	-
Decommissioning obligations	8,475	200	-	8,275
Office leases	643	594	49	-
Firm transportation agreements	21,024	5,298	15,093	633
Total contractual obligations	41,854	17,804	15,142	8,908

Transportation commitments include contracts to transport natural gas and NGLs through third-party owned pipeline systems. The Company currently has commitments of 15 mmcf/d escalating over time to 33.3 mmcf/d.

The Company has until December 31, 2018 to incur the required Canadian exploration expenditures of $5.0 million related to the issuance of flow-through common shares on April 26, 2017.

The Company has committed to drill a horizontal well into the Montney formation in Two Rivers, BC prior to December 31, 2017.

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)	**September 30, 2017**	November 27, 2017
Voting common shares	**200,479**	200,479
Warrants	**15,141**	15,141
Stock options	**11,488**	11,488
Total	**227,108**	227,108

SUMMARY OF QUARTERLY RESULTS

	Q3 2017	Q2 2017	Q1 2017	Q4 2016	Q3 2016	Q2 2016	Q1 2016	Q4 2015
Average Daily Production								
Oil and NGLs (bbls/d)	**857**	609	514	234	300	319	412	479
Natural gas (mcf/d)	**13,593**	12,122	8,197	3,543	4,138	4,549	5,031	3,585
Combined (boe/d)	**3,123**	2,629	1,881	824	989	1,078	1,251	1,076
($000s, except per share amounts)								
Oil and natural gas sales	**5,908**	6,467	4,883	2,281	2,309	1,953	2,301	2,819
Funds from (used in) operations	**1,747**	2,097	1,296	(98)	(124)	(491)	(283)	464
Per share - basic and diluted	**0.01**	0.01	0.01	-	-	-	-	-
Net loss	**(1,549)**	(723)	(878)	(1,657)	(4,994)	(2,758)	(2,773)	(15,205)
Per share - basic and diluted	**(0.01)**	-	(0.01)	(0.01)	(0.03)	(0.02)	(0.02)	(0.09)

Production, oil and natural gas sales and funds from operations increased significantly in each quarter of 2017 from the successful drilling at Doe/Mica in the Montney formation.

The large net loss in Q4 2015 was mainly the result of impairment charges on non-Montney assets and derecognizing the deferred income tax asset. 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.

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, 2016 for full descriptions of the use of estimates and judgments).

FUTURE ACCOUNTING PRONOUNCEMENTS

On May 28, 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers", which specifies how and when to recognize revenue as well as requiring entities to provide users of financial statements with more disclosure. IFRS 15 will replace IAS 11 "Construction Contracts", IAS 18 "Revenue", IFRIC 13 "Customer Loyalty Programs", IFRIC 15 "Agreements for the Construction of Real Estate", IFRIC 18 "Transfer of Assets from Customers", and SIC 31 "Revenue – Barter Transactions Involving Advertising Services". IFRS 15 will be effective for annual periods beginning on or after January 1, 2018. Application of the standard is mandatory and early adoption is permitted. The Company intends to adopt IFRS 15 in its financial statements for the annual period beginning on January 1, 2018. The Company is in the process of reviewing its revenue streams and underlying contracts with customers to determine the impact, if any, that the adoption of IFRS 15 will have on its financial statements and related disclosure.

On July 24, 2014, the IASB issued the complete IFRS 9. In November 2009 the IASB issued the first version of IFRS 9, "Financial Instruments" and subsequently issued various amendments in October 2010 and November 2013. The mandatory effective date of IFRS 9 is for annual periods beginning on or after January 1, 2018 and must be applied retrospectively with some exemptions. Early adoption is permitted. The standard introduces new requirements for classifying and measuring financial instruments and includes a new general hedge accounting standard that will provide more risk management strategies to qualify for hedge accounting. The Company intends to adopt IFRS 9 in its financial statements for the annual period beginning on January 1, 2018. The Company is in the process of evaluating the impact of this standard on its financial statements and does not anticipate material changes.

On January 13, 2016, the IASB issued IFRS 16 "Leases". 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 "Revenue from Contracts with Customers" 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 be classified as leases and evaluating the impact of this standard on its financial statements.

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 funds from operations 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 crude 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 September 30, 2017 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 September 30, 2017, 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 September 30, 2017, $2.0 million (82%) of the Company's outstanding accounts receivable were current and $0.1 million (4%) were outstanding for more than 90 days. During the period ended September 30, 2017, the Company did not deem any outstanding accounts receivable to be uncollectable.

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 commitments for firm transportation over the next four years for a total of $21.0 million. The Company has a working capital balance of $29.2 million including $37.2 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.

PRODUCTION RATES

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

TYPE CURVES

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

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

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, oil, NGLs, and natural gas commodity prices, production expenses 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	September 30 2017	December 31 2016
Assets			
Current assets			
Cash and cash equivalents		**37,231**	32,997
Restricted cash		**1,000**	1,000
Accounts receivable		**2,387**	1,518
Prepaid expenses and deposits		**342**	199
		40,960	35,714
Property, plant, and equipment	(4)	**135,653**	117,381
Exploration and evaluation assets	(5)	**142,770**	88,540
		278,423	205,921
		319,383	241,635
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		**11,712**	9,651
Decommissioning obligations	(7)	**8,475**	6,820
Flow-through share premium	(8)	**833**	-
		21,020	16,471
Shareholders' Equity			
Shareholders' capital	(8)	**288,765**	213,875
Contributed surplus		**13,952**	12,493
Deficit		**(4,354)**	(1,204)
		298,363	225,164
		319,383	241,635
Commitments	(8,12)		

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

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

($000s, except per share amounts)	Note	Three Months Ended September 30 2017	Three Months Ended September 30 2016	Nine Months Ended September 30 2017	Nine Months Ended September 30 2016
Revenue					
Oil and natural gas sales		**5,908**	2,309	**17,258**	6,563
Royalties		**(479)**	(200)	**(1,306)**	(431)
		5,429	2,109	**15,952**	6,132
Expenses					
Production		**1,938**	1,012	**5,038**	3,010
Transportation		**846**	332	**2,755**	1,019
Depletion and depreciation	(4)	**2,853**	1,408	**6,990**	3,960
General and administrative		**1,029**	992	**3,313**	3,366
Share based compensation	(9)	**406**	868	**1,187**	3,007
Loss on sale of equipment		**-**	2,563	**-**	2,563
Finance income		**(155)**	(119)	**(358)**	(393)
Finance expense		**61**	47	**177**	125
		6,978	7,103	**19,102**	16,657
Net loss and comprehensive loss		**(1,549)**	(4,994)	**(3,150)**	(10,525)
Net loss per share					
Basic and diluted	(10)	**(0.01)**	(0.03)	**(0.02)**	(0.06)

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	Reserve from common-control transaction	Retained Earnings (Deficit)	Total Equity
Balance, December 31, 2015	283,587	8,405	(69,712)	10,978	233,258
Net loss	-	-	-	(10,525)	(10,525)
Share based compensation	-	3,354	-	-	3,354
Reclassification	(69,712)	-	69,712	-	-
Balance, September 30, 2016	213,875	11,759	-	453	226,087
Balance, December 31, 2016	213,875	12,493	-	(1,204)	225,164
Net loss	-	-	-	(3,150)	(3,150)
Issue of shares (net of share issue costs and flow-through share premium)	74,774	-	-	-	74,774
Exercise of warrants and stock options	116	(34)	-	-	82
Share based compensation	-	1,493	-	-	1,493
Balance, September 30, 2017	288,765	13,952	-	(4,354)	298,363

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

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

($000s)	Note	Three Months Ended September 30 2017	Three Months Ended September 30 2016	Nine Months Ended September 30 2017	Nine Months Ended September 30 2016
Operating Activities					
Net loss		**(1,549)**	(4,994)	**(3,150)**	(10,525)
Depletion and depreciation	(4)	**2,853**	1,408	**6,990**	3,960
Share based compensation	(9)	**406**	868	**1,187**	3,007
Finance expense		**61**	47	**177**	125
Interest paid		**(24)**	(16)	**(64)**	(28)
Loss on sale of equipment		**-**	2,563	**-**	2,563
Change in non-cash working capital	(11)	**(425)**	1,237	**(123)**	1,515
		1,322	1,113	**5,017**	617
Financing Activities					
Issue of shares		**-**	-	**80,001**	-
Share issue costs		**(6)**	-	**(4,394)**	-
Exercise of warrants and stock options		**6**	-	**82**	-
		-	-	**75,689**	-
Investing Activities					
Capital expenditures - property, plant, and equipment	(4)	**(2,816)**	(4,340)	**(23,537)**	(5,605)
Capital expenditures - exploration and evaluation assets	(5)	**(13,500)**	(1,035)	**(18,557)**	(1,717)
Property acquisitions (net)	(5)	**-**	(400)	**(35,550)**	(3,534)
Disposition of equipment		**-**	4,000	**-**	4,000
Change in non-cash working capital	(11)	**2,382**	3,896	**1,172**	(6,208)
		(13,934)	2,121	**(76,472)**	(13,064)
Change in cash and cash equivalents		**(12,612)**	3,234	**4,234**	(12,447)
Cash and cash equivalents, beginning of period		**49,843**	38,123	**32,997**	53,804
Cash and cash equivalents, end of period		**37,231**	41,357	**37,231**	41,357

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, 2016.

The condensed interim financial statements were authorized for issuance by the Board of Directors on November 27, 2017.

(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, 2016.

(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 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, 2016.

3. SIGNIFICANT ACCOUNTING POLICIES

The condensed interim financial statements have been prepared following the same accounting policies as the annual financial statements for the year ended December 31, 2016. The accounting policies have been applied consistently by the Company to all periods presented in these condensed interim financial statements.

(a) New standards and interpretations not yet adopted

On May 28, 2014, the IASB issued IFRS 15 "Revenue from Contracts with Customers", which specifies how and when to recognize revenue as well as requiring entities to provide users of financial statements with more disclosure. IFRS 15 will replace IAS 11 "Construction Contracts", IAS 18 "Revenue", IFRIC 13 "Customer Loyalty Programs", IFRIC 15 "Agreements for the Construction of Real Estate", IFRIC 18 "Transfer of Assets from Customers", and SIC 31 "Revenue – Barter Transactions Involving Advertising Services". IFRS 15 will be effective for annual periods beginning on or after January 1, 2018. Application of the standard is mandatory and early adoption is permitted. The Company intends to adopt IFRS 15 in its financial statements for the annual period beginning on January 1, 2018. The Company is in the process of reviewing its revenue streams and underlying contracts with customers to determine the impact, if any, that the adoption of IFRS 15 will have on its financial statements and related disclosure.

On July 24, 2014, the IASB issued the complete IFRS 9. In November 2009 the IASB issued the first version of IFRS 9, "Financial Instruments" and subsequently issued various amendments in October 2010 and November 2013. The mandatory effective date of IFRS 9 is for annual periods beginning on or after January 1, 2018 and must be applied retrospectively with some exemptions. Early adoption is permitted. The standard introduces new requirements for classifying and measuring financial instruments and includes a new general hedge accounting standard that will provide more risk management strategies to qualify for hedge accounting. The Company intends to adopt IFRS 9 in its financial statements for the annual period beginning on January 1, 2018. The Company is in the process of evaluating the impact of this standard on its financial statements and does not anticipate material changes.

On January 13, 2016, the IASB issued IFRS 16 “Leases”. 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 “Revenue from Contracts with Customers” 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 be classified as leases and evaluating the impact of this standard on its financial statements.

4. PROPERTY, PLANT, AND EQUIPMENT

Cost	**Total**
Balance, December 31, 2015	129,411
Additions	10,190
Dispositions	(6,563)
Transfer from exploration and evaluation assets	10,086
Change in decommissioning obligations	21
Capitalized share based compensation	45
Balance, December 31, 2016	143,190
Additions	**23,537**
Change in decommissioning obligations	**1,542**
Capitalized share based compensation	**183**
Balance, September 30, 2017	**168,452**

Accumulated Depletion, Depreciation, and Impairment	**Total**
Balance, December 31, 2015	20,858
Depletion and depreciation	4,951
Balance, December 31, 2016	25,809
Depletion and depreciation	**6,990**
Balance, September 30, 2017	**32,799**

Net Book Value	**Total**
December 31, 2016	117,381
September 30, 2017	**135,653**

During the three and nine months ended September 30, 2017, $0.1 million (September 30, 2016 - $nil) and $0.4 million (September 30, 2016 - $nil), respectively, 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 September 30, 2017 included an estimated $77.2 million (September 30, 2016 - $69.0 million) for future development costs associated with proved plus probable undeveloped reserves and excluded approximately $3.7 million (September 30, 2016 - $1.4 million) for the estimated salvage value of production equipment and facilities.

5. EXPLORATION AND EVALUATION ASSETS

	Total
Balance, December 31, 2015	85,745
Property acquisitions	4,034
Additions	8,350
Transfer to property, plant, and equipment	(10,086)
Capitalized share based compensation	497
Balance, December 31, 2016	88,540
Property acquisitions (net)	**35,550**
Additions	**18,557**
Capitalized share based compensation	**123**
Balance, September 30, 2017	**142,770**

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. All expenditures for the three and nine months ended September 30, 2017 and year ended December 31, 2016 related to Northeast BC.

During the three and nine months ended September 30, 2017, approximately $0.2 million (September 30, 2016 - $0.1 million) and $0.2 million (September 30, 2016 - $0.2 million), respectively, of directly attributable general and administrative costs were capitalized as expenditures on exploration and evaluation assets.

During the nine months ended September 30, 2017, the Company had net property acquisitions of $35.6 million. 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.

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. At September 30, 2017, $nil had been drawn on the revolving credit facility. At September 30, 2017, the Company had outstanding letters of guarantee of $1.9 million which reduce the amount that can be borrowed under the credit facility.

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 September 30, 2017.

The next review of the revolving credit facility by the bank is scheduled on or before December 1, 2017.

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 $15.1 million (December 31, 2016 - $12.1 million) which is estimated to be incurred over the next 33 years. At September 30, 2017, a risk-free rate of 2.4% (December 31, 2016 - 2.2%) was used to calculate the net present value of the decommissioning obligations.

	Nine Months Ended September 30, 2017	Year Ended December 31, 2016
Balance, beginning of period	**6,820**	6,673
Provisions incurred	**1,469**	339
Revisions due to change of discount rates	**(300)**	(318)
Revisions due to change of estimates	**373**	-
Accretion	**113**	126
Balance, end of period	**8,475**	6,820

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, 2015	165,227	283,587
Reclassification of Reserve from common-control transaction	-	(69,712)
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	**67**	**116**
Balance, September 30, 2017	**200,479**	**288,765**

On April 26, 2017, the Company closed a bought-deal public financing for an aggregate of 33,333,400 common shares at a price of $2.25 per common share and 1,852,000 common shares on a flow-through basis at a price of $2.70 per flow-through common share for total gross proceeds of $80.0 million. Upon issuance, the premium received on the flow-through shares, being the difference between the fair value of the flow-through shares issued and the fair value of the common shares at the date of issuance, was recognized as a liability. The Company has until December 31, 2018 to incur the required Canadian exploration expenditures of $5.0

million related to the flow-through shares. The proceeds of the financing were used to fund the property acquisition (note 5) and the Company's 2017 capital program.

In connection with the arrangement on June 12, 2014 involving Crocotta Energy Inc. ("Crocotta") and Long Run Exploration Ltd., the reserve created from the common-control transaction represents the difference between the fair value of the Leucrotta shares issued to existing Crocotta shareholders and the net book value of the acquired assets and assumed liabilities, and has been reclassified to Shareholders' Capital.

9. SHARE BASED COMPENSATION PLANS

Stock options

The Company has authorized and reserved for issuance 20.0 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 September 30, 2017, 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, 2015	8,895	1.09
Granted	25	1.40
Balance, December 31, 2016	8,920	1.09
Granted	**2,626**	**1.78**
Exercised	**(58)**	**1.16**
Balance, September 30, 2017	**11,488**	**1.25**
Exercisable, September 30, 2017	4,481	1.16

During the three and nine months ended September 30, 2017, the Company recognized $0.2 million (September 30, 2016 - $0.4 million) and $0.6 million (September 30, 2016 - $1.2 million), respectively, of share based compensation related to the stock options. At September 30, 2017 there was $2.2 million remaining as unrecognized share based compensation related to the stock options.

Performance Warrants

	Number	Exercise Price
Balance, December 31, 2015 and 2016	7,500	1.70
Exercised	**(9)**	**1.70**
Balance, September 30, 2017	**7,491**	**1.70**
Exercisable, September 30, 2017	4,491	1.70

During the three and nine months ended September 30, 2017, the Company recognized $0.2 million (September 30, 2016 - $0.4 million) and $0.5 million (September 30, 2016 - $1.1 million), respectively, of share based compensation related to the performance warrants. At September 30, 2017 there was $nil remaining as unrecognized share based compensation related to the performance warrants.

Purchase Warrants

During the three and nine months ended September 30, 2017, the Company recognized $0.1 million (September 30, 2016 - $0.3 million) and $0.4 million (September 30, 2016 - $1.0 million), respectively, of share based compensation related to the purchase warrants. At September 30, 2017 there was $nil remaining as unrecognized share based compensation related to the purchase warrants. No new purchase warrants were granted during the nine months ended September 30, 2017.

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:

	Nine Months Ended September 30	
	2017	2016
Risk-free interest rate (%)	**1.7**	0.5
Expected life (years)	**4.0**	3.5
Expected volatility (%)	**52.8**	63.3
Expected dividend yield (%)	**-**	-
Forfeiture rate (%)	**0.2**	5.0
Weighted average fair value of options granted ($ per option)	**0.75**	0.63

10. PER SHARE AMOUNTS

At September 30, 2017 there were 11.5 million stock options, 7.7 million purchase warrants and 7.5 million performance warrants that were anti-dilutive due to the net loss.

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	2016	**2017**	2016
Weighted average number of shares - basic and diluted	**200,479**	165,227	**185,633**	165,227

11. SUPPLEMENTAL CASH FLOW INFORMATION

	Three Months Ended September 30		Nine Months Ended September 30	
	2017	2016	**2017**	2016
Restricted cash	**-**	1,131	**-**	1,131
Accounts receivable	**(302)**	(289)	**(869)**	912
Prepaid expenses and deposits	**(217)**	(119)	**(143)**	55
Accounts payable and accrued liabilities	**2,476**	4,410	**2,061**	(6,791)
Change in non-cash working capital	**1,957**	5,133	**1,049**	(4,693)
Relating to:				
Investing	**2,382**	3,896	**1,172**	(6,208)
Operating	**(425)**	1,237	**(123)**	1,515
Change in non-cash working capital	**1,957**	5,133	**1,049**	(4,693)

12. COMMITMENTS

The following is a summary of the Company's contractual obligations and commitments at September 30, 2017:

	2017	2018	2019	2020	2021	Thereafter	Total
Office leases	147	496	-	-	-	-	643
Firm transportation agreements	1,088	5,613	7,894	6,429	-	-	21,024
	1,235	6,109	7,894	6,429	-	-	21,667

Transportation commitments include contracts to transport natural gas and NGLs through third-party owned pipeline systems. The Company currently has commitments of 15 mmcf/d escalating over time to 33.3 mmcf/d.

The Company has until December 31, 2018 to incur the required Canadian exploration expenditures of $5.0 million related to the issuance of flow-through common shares on April 26, 2017 (note 8).

The Company has committed to drill a horizontal well into the Montney formation in Two Rivers, BC prior to December 31, 2017.

CORPORATE INFORMATION

OFFICERS AND DIRECTORS

Robert J. Zakresky, CA
President, CEO & Director

Nolan Chicoine, MPAcc, CA
VP Finance & CFO

Terry L. Trudeau, P.Eng.
VP Operations & COO

R.D. (Rick) Sereda, M.Sc., P.Geol.
VP Exploration

Helmut R. Eckert, P.Land
VP Land

Peter Cochrane, P.Eng.
VP Engineering

Daryl H. Gilbert, P.Eng.
Chairman of the Board

John A. Brussa, B.A., LL.B.
Director

Don Cowie
Director

Kelvin B. Johnston, P.Geol.
Director

Brian Krausert, B.Sc.
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Tom J. Medvedic, CA
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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).