

# Q2 2018 RESULTS

FINANCIAL AND OPERATING RESULTS FOR THE  
THREE AND SIX MONTHS ENDED **JUNE 30, 2018**



## HIGHLIGHTS

- Increased production 33% to 3,487 boe/d in Q2 2018 from 2,629 boe/d in Q2 2017.
- Increased adjusted funds flow 60% to \$3.3 million in Q2 2018 from \$2.1 million in Q2 2017.
- Maintained working capital of \$14.5 million.

FINANCIAL RESULTS (\$000s, except per share amounts)	THREE MONTHS ENDED JUNE 30			SIX MONTHS ENDED JUNE 30		
	2018	2017	% Change	2018	2017	% Change
<b>OIL AND NATURAL GAS SALES</b>	<b>7,327</b>	6,317	16	<b>17,753</b>	11,100	60
<b>ADJUSTED FUNDS FLOW<sup>(1)</sup></b>	<b>3,348</b>	2,097	60	<b>9,735</b>	3,393	187
Per share - basic and diluted	<b>0.02</b>	0.01	100	<b>0.05</b>	0.02	150
<b>NET (LOSS) EARNINGS</b>	<b>(2,280)</b>	(723)	215	<b>266</b>	(1,601)	(117)
Per share - basic and diluted	<b>(0.01)</b>	-	100	<b>-</b>	(0.01)	(100)
<b>NET CAPITAL EXPENDITURES AND ACQUISITIONS</b>	<b>2,400</b>	42,810	(94)	<b>13,860</b>	61,328	(77)
<b>WORKING CAPITAL</b>				<b>14,467</b>	43,817	(67)
<b>COMMON SHARES OUTSTANDING (000S)</b>						
Weighted average - basic	<b>200,517</b>	190,795	5	<b>200,517</b>	178,087	13
Weighted average - diluted	<b>200,517</b>	190,795	5	<b>203,733</b>	178,087	14
End of period - basic				<b>200,517</b>	200,470	-
End of period - fully diluted				<b>227,093</b>	224,482	1

(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 <sup>(1)</sup>	Three Months Ended June 30			Six Months Ended June 30		
	2018	2017	% Change	2018	2017	% Change
<b>Daily production</b>						
Oil and NGLs (bbls/d)	938	609	54	1,040	562	85
Natural gas (mcf/d)	15,297	12,122	26	16,748	10,170	65
Oil equivalent (boe/d)	3,487	2,629	33	3,832	2,257	70
<b>Revenue</b>						
Oil and NGLs (\$/bbl)	65.09	53.91	21	63.44	55.68	14
Natural gas (\$/mcf)	1.27	3.02	(58)	1.92	2.95	(35)
Oil equivalent (\$/boe)	23.09	26.40	(13)	25.60	27.17	(6)
<b>Royalties</b>						
Oil and NGLs (\$/bbl)	0.75	8.53	(91)	0.34	6.22	(95)
Natural gas (\$/mcf)	-	0.08	(100)	-	0.11	(100)
Oil equivalent (\$/boe)	0.20	2.33	(91)	0.09	2.02	(96)
<b>Net operating expenses <sup>(2)</sup></b>						
Oil and NGLs (\$/bbl)	8.27	7.10	16	7.21	9.21	(22)
Natural gas (\$/mcf)	0.94	1.01	(7)	0.86	1.04	(17)
Oil equivalent (\$/boe)	6.37	6.30	1	5.70	6.98	(18)
<b>Net transportation expenses <sup>(2)</sup></b>						
Oil and NGLs (\$/bbl)	1.13	3.72	(70)	1.91	3.72	(49)
Natural gas (\$/mcf)	0.38	0.74	(49)	0.41	0.83	(51)
Oil equivalent (\$/boe)	1.97	4.29	(54)	2.31	4.67	(51)
<b>Operating netback <sup>(2)</sup></b>						
Oil and NGLs (\$/bbl)	54.94	34.56	59	53.98	36.53	48
Natural gas (\$/mcf)	(0.05)	1.19	(104)	0.65	0.97	(33)
Oil equivalent (\$/boe)	14.55	13.48	8	17.50	13.50	30
Depletion and depreciation (\$/boe)	(9.25)	(9.95)	(7)	(9.31)	(10.13)	(8)
General and administrative expenses (\$/boe)	(4.15)	(5.02)	(17)	(3.65)	(5.59)	(35)
Share based compensation (\$/boe)	(8.32)	(1.68)	395	(4.20)	(1.91)	120
Finance expense (\$/boe)	(0.26)	(0.32)	(19)	(0.20)	(0.28)	(29)
Finance income (\$/boe)	0.25	0.47	(47)	0.25	0.50	(50)
<b>Net (loss) earnings (\$/boe)</b>	<b>(7.18)</b>	<b>(3.02)</b>	<b>138</b>	<b>0.39</b>	<b>(3.91)</b>	<b>(110)</b>

(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")

August 28, 2018

The MD&A should be read in conjunction with the unaudited condensed interim financial statements and related notes for the three and six months ended June 30, 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.

### 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 Q2 2018, Leucrotta's capital was spent predominantly on pipelines and facilities in preparation for new wells coming on-stream in late 2018 and early 2019. The previously drilled wells at Mica 1-24 and Mica North 5-19 will be completed during Q3 2018 with data accumulated and released sometime in mid to late October. Both wells were drilled into the Lower Montney Turbidite light oil formation with the 5-19 well being a major step-out to the north.

Leucrotta will also continue to delineate the Upper Montney light oil lands with a well scheduled to be drilled and completed at Mica in Q4 2018 as an exploratory test following up on the previously released Upper Montney light oil well at Two Rivers. The 10-08 Two Rivers well tested approximately 1,840 boepd (37% oil and liquids) on the last day of a 10-day test. A successful well at Mica would materially add to Leucrotta's light oil drilling inventory.

Leucrotta will also drill an exploratory vertical well for a Montney zone below the Lower Montney Turbidite termed the "BLM" zone for Below Lower Montney. A Montney competitor has recently announced a highly productive well into this zone in the Pouce Coupe area. Leucrotta believes its lands are within the light oil window versus the gas window at Pouce Coupe. We will look to drill a horizontal well into the BLM zone pending a successful vertical test.

Leucrotta continues to maintain a strong balance sheet with net working capital of \$14.5 million at the end of Q2 2018 and has projected to have positive working capital at year-end with an unused bank credit facility of \$20 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

(\$000s, except per share amounts)	Three Months Ended June 30			Six Months Ended June 30		
	2018	2017	% Change	2018	2017	% Change
<b>Oil and natural gas sales</b>	<b>7,327</b>	6,317	16	<b>17,753</b>	11,100	60
<b>Adjusted funds flow</b>	<b>3,348</b>	2,097	60	<b>9,735</b>	3,393	187
Per share - basic and diluted	<b>0.02</b>	0.01	100	<b>0.05</b>	0.02	150
<b>Net (loss) earnings</b>	<b>(2,280)</b>	(723)	215	<b>266</b>	(1,601)	(117)
Per share - basic and diluted	<b>(0.01)</b>	-	100	-	(0.01)	(100)
<b>Total assets</b>				<b>310,712</b>	316,966	(2)
<b>Total long-term liabilities</b>				<b>9,353</b>	8,337	12
<b>Working capital</b>				<b>14,467</b>	43,817	(67)

The Company experienced an increase in oil and natural gas sales and adjusted funds flow for the three and six months ended June 30, 2018 compared to 2017 due to production growth from successful drilling at Doe/Mica and higher oil and NGLs commodity prices, partially offset by significantly lower natural gas prices. Despite the increase in oil and natural gas sales and adjusted funds flow, the net loss in Q2 2018 increased over the comparative quarter in 2017 due to non-cash share based compensation expense related to the expiry term extension of existing stock options, performance warrants and purchase warrants. This expense also affected the six month period ending June 30, 2018. The decrease in working capital from June 30, 2017 to June 30, 2018 stems mainly from \$46.0 million of capital expenditures over the past twelve months partially offset by \$15.9 million of adjusted funds flow.

## PRODUCTION

	Three Months Ended June 30			Six Months Ended June 30		
	2018	2017	% Change	2018	2017	% Change
Average Daily Production						
Oil and NGLs (bbls/d)	<b>938</b>	609	54	<b>1,040</b>	562	85
Natural gas (mcf/d)	<b>15,297</b>	12,122	26	<b>16,748</b>	10,170	65
Combined (boe/d)	<b>3,487</b>	2,629	33	<b>3,832</b>	2,257	70

Daily production increased to 3,487 boe/d and 3,832 boe/d for the three and six months ended June 30, 2018, respectively, from 2,629 boe/d and 2,257 boe/d for the comparative periods 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).

Leucrotta's production profile for the second quarter of 2018 saw an increase in liquids weighting over the comparative quarter in 2017 due to new oil wells drilled at Mica. The Q2 2018 weighting was 73% natural gas (Q2 2017 - 77%) and 27% oil and NGLs (Q2 2017 - 23%).

## OIL AND NATURAL GAS SALES

(\$000s)	Three Months Ended June 30			Six Months Ended June 30		
	2018	2017	% Change	2018	2017	% Change
Oil and NGLs	<b>5,555</b>	2,987	86	<b>11,948</b>	5,664	111
Natural gas	<b>1,772</b>	3,330	(47)	<b>5,805</b>	5,436	7
Total	<b>7,327</b>	6,317	16	<b>17,753</b>	11,100	60
Average Sales Price						
Oil and NGLs (\$/bbl)	<b>65.09</b>	53.91	21	<b>63.44</b>	55.68	14
Natural gas production sales and transportation revenue (\$/mcf)	<b>1.27</b>	3.02	(58)	<b>1.92</b>	2.95	(35)
Combined (\$/boe)	<b>23.09</b>	26.40	(13)	<b>25.60</b>	27.17	(6)

Revenue totaled \$7.3 million and \$17.8 million for the three and six months ended June 30, 2018, respectively, compared to \$6.3 million and \$11.1 million for the comparative periods in 2017. The increase was mainly the result of production growth from successful drilling at Doe/Mica and higher oil and NGLs commodity prices, partially offset by significantly lower natural gas prices.

PROCESSING AND MARKETING REVENUE (\$000s)	Three Months Ended June 30			Six Months Ended June 30		
	2018	2017	% Change	2018	2017	% Change
Sale of purchased natural gas	295	70	321	295	1,309	(77)
Processing revenue	176	-	100	422	-	100
Marketing revenue	152	-	100	304	-	100
<b>Total</b>	<b>623</b>	<b>70</b>	<b>790</b>	<b>1,021</b>	<b>1,309</b>	<b>(22)</b>

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

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

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

Commodity Pricing	Three Months Ended June 30			Six Months Ended June 30		
	2018	2017	% Change	2018	2017	% Change
<b>Oil and NGLs</b>						
Corporate price (\$CDN/bbl)	65.09	53.91	21	63.44	55.68	14
Canadian light sweet (\$CDN/bbl)	77.82	59.72	30	73.95	62.27	19
West Texas Intermediate ("WTI") (\$US/bbl)	67.88	48.27	41	65.38	50.09	31
<b>Natural gas</b>						
Corporate price (\$CDN/mcf)	1.27	3.02	(58)	1.92	2.95	(35)
AECO price (\$CDN/mcf)	1.20	2.79	(57)	1.63	2.74	(41)
<b>Exchange rate</b>						
\$US/\$CAD exchange rate	0.7748	0.7440	4	0.7828	0.7499	4

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 83.6% and 85.8% of Canadian light sweet prices for the three and six months ended June 30, 2018, respectively, down from 90.3% and 89.4% for the comparative periods in 2017.

Corporate average natural gas prices were 105.8% and 117.8% of AECO prices for the three and six months ended June 30, 2018, respectively, compared to 108.2% and 107.7% for the comparative periods in 2017.

Leucrotta's liquids mix during the second quarter of 2018 was approximately 67% oil, condensate and pentanes, 11% butane and 22% propane (Q2 2017 - 77% oil, condensate and pentanes, 8% butane and 15% 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 (\$000s)	Three Months Ended June 30			Six Months Ended June 30		
	2018	2017	% Change	2018	2017	% Change
Oil and NGLs	65	473	(86)	65	633	(90)
Natural gas	-	85	(100)	-	194	(100)
<b>Total</b>	<b>65</b>	<b>558</b>	<b>(88)</b>	<b>65</b>	<b>827</b>	<b>(92)</b>
<b>Average Royalty Rate (% of sales)</b>						
Oil and NGLs	1.2	15.8	(92)	0.5	11.2	(96)
Natural gas	-	2.6	(100)	-	3.6	(100)
<b>Combined</b>	<b>0.9</b>	<b>8.8</b>	<b>(90)</b>	<b>0.4</b>	<b>7.5</b>	<b>(95)</b>

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 six months ended June 30, 2018, the Company began receiving credits to offset royalties from BC's Infrastructure Royalty Credit Program ("IRCP") resulting from infrastructure built in 2017 and wells drilled and tied-into the related infrastructure. During the three and six months ended June 30, 2018, the Company realized \$0.6 million and \$1.4 million, respectively, of credits to offset royalties

payable and has \$nil credits remaining. 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 \$2.0 million in remaining royalty credits.

NET OPERATING EXPENSES (\$000s)	Three Months Ended June 30			Six Months Ended June 30		
	2018	2017	% Change	2018	2017	% Change
Oil and NGLs	706	394	79	1,357	938	45
Natural gas	1,491	1,114	34	3,018	1,912	58
Operating expenses	2,197	1,508	46	4,375	2,850	54
Less: processing revenue	(176)	-	100	(422)	-	100
Net operating expenses (non-GAAP)	2,021	1,508	34	3,953	2,850	39
Average net operating expenses						
Oil and NGLs (\$/bbl)	8.27	7.10	16	7.21	9.21	(22)
Natural gas (\$/mcf)	0.94	1.01	(7)	0.86	1.04	(17)
Combined (\$/boe)	6.37	6.30	1	5.70	6.98	(18)

Per unit net operating expenses were \$6.37/boe and \$5.70/boe for the three and six months ended June 30, 2018, respectively, compared to \$6.30/boe and \$6.98/boe in the comparative periods in 2017. The large decrease in the six months ended June 30, 2018 from the comparative period in 2017 was the result of increased production from the tie-in of previously drilled wells into the Company's Doe gas plant thereby spreading the fixed gas plant expenses over a larger production base. Despite these economies of scale, the second quarter of 2018 saw increased maintenance, property taxes and carbon taxes over Q2 2017 bringing net operating expenses per boe back up to 2017 levels.

#### NET TRANSPORTATION AND MARKETING EXPENSES

(\$000s)	Three Months Ended June 30			Six Months Ended June 30		
	2018	2017	% Change	2018	2017	% Change
Oil and NGLs transportation	96	206	(53)	359	379	(5)
Natural gas transportation	770	837	(8)	1,635	1,699	(4)
Transportation expenses	866	1,043	(17)	1,994	2,078	(4)
Purchased natural gas	205	54	280	205	1,140	(82)
Transportation and marketing expenses	1,071	1,097	(2)	2,199	3,218	(32)
Less: sale of purchased natural gas	(295)	(70)	321	(295)	(1,309)	(77)
Less: marketing revenue	(152)	-	100	(304)	-	100
Net transportation expenses (non-GAAP)	624	1,027	(39)	1,600	1,909	(16)
Average net transportation and marketing expenses						
Oil and NGLs (\$/bbl)	1.13	3.72	(70)	1.91	3.72	(49)
Natural gas (\$/mcf)	0.38	0.74	(49)	0.41	0.83	(51)
Combined (\$/boe)	1.97	4.29	(54)	2.31	4.67	(51)

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 \$1.97/boe and \$2.31/boe for the three and six months ended June 30, 2018, respectively, compared to \$4.29/boe and \$4.67/boe for the comparative periods in 2017.

The decrease in natural gas transportation in the first half of 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 first half of 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. Net transportation and marketing expenses also deduct the marketing revenue the Company generates from the premium received on assigned unutilized firm transportation.

OPERATING NETBACK	Three Months Ended June 30			Six Months Ended June 30		
	2018	2017	% Change	2018	2017	% Change
<b>Oil and NGLs (\$/bbl)</b>						
Revenue	65.09	53.91	21	63.44	55.68	14
Royalties	(0.75)	(8.53)	(91)	(0.34)	(6.22)	(95)
Net operating expenses	(8.27)	(7.10)	16	(7.21)	(9.21)	(22)
Net transportation and marketing expenses	(1.13)	(3.72)	(70)	(1.91)	(3.72)	(49)
Operating netback	54.94	34.56	59	53.98	36.53	48
<b>Natural gas (\$/mcf)</b>						
Revenue	1.27	3.02	(58)	1.92	2.95	(35)
Royalties	-	(0.08)	(100)	-	(0.11)	(100)
Net operating expenses	(0.94)	(1.01)	(7)	(0.86)	(1.04)	(17)
Net transportation and marketing expenses	(0.38)	(0.74)	(49)	(0.41)	(0.83)	(51)
Operating netback	(0.05)	1.19	(104)	0.65	0.97	(33)
<b>Combined (\$/boe)</b>						
Revenue	23.09	26.40	(13)	25.60	27.17	(6)
Royalties	(0.20)	(2.33)	(91)	(0.09)	(2.02)	(96)
Net operating expenses	(6.37)	(6.30)	1	(5.70)	(6.98)	(18)
Net transportation and marketing expenses	(1.97)	(4.29)	(54)	(2.31)	(4.67)	(51)
Operating netback	14.55	13.48	8	17.50	13.50	30

During the three and six months ended June 30, 2018, Leucrotta generated an operating netback of \$14.55/boe and \$17.50/boe, respectively, up from \$13.48/boe and \$13.50/boe for the comparative periods in 2017. The large increase in oil and NGLs netbacks was mainly due to higher commodity prices and lower net transportation expenses per boe and royalty credits from BC's IRCP. The large decrease in natural gas netbacks stems mainly from lower prices received in 2018 compared to 2017.

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

(\$/boe)	Three Months Ended June 30			Six Months Ended June 30		
	2018	2017	% Change	2018	2017	% Change
<b>Operating netback</b>	14.55	13.48	8	17.50	13.50	30
Depletion and depreciation	(9.25)	(9.95)	(7)	(9.31)	(10.13)	(8)
General and administrative expenses	(4.15)	(5.02)	(17)	(3.65)	(5.59)	(35)
Share based compensation	(8.32)	(1.68)	395	(4.20)	(1.91)	120
Finance expense	(0.26)	(0.32)	(19)	(0.20)	(0.28)	(29)
Finance income	0.25	0.47	(47)	0.25	0.50	(50)
<b>Net (loss) earnings (GAAP)</b>	(7.18)	(3.02)	138	0.39	(3.91)	(110)

DEPLETION AND DEPRECIATION	Three Months Ended June 30			Six Months Ended June 30		
	2018	2017	% Change	2018	2017	% Change
Depletion and depreciation (\$000s)	2,936	2,381	23	6,460	4,137	56
Depletion and depreciation (\$/boe)	9.25	9.95	(7)	9.31	10.13	(8)

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 six months ended June 30, 2018 was \$9.25/boe and \$9.31/boe, respectively, consistent with \$9.95/boe and \$10.13/boe for the comparative periods 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 (\$000s)	Three Months Ended June 30			Six Months Ended June 30		
	2018	2017	% Change	2018	2017	% Change
G&A expenses (gross)	1,366	1,251	9	2,760	2,590	7
G&A capitalized	(47)	(128)	(63)	(225)	(375)	(40)
G&A recoveries	(1)	79	(101)	(2)	69	(103)
G&A expenses (net)	1,318	1,202	10	2,533	2,284	11
G&A expenses (\$/boe)	4.15	5.02	(17)	3.65	5.59	(35)

General and administrative ("G&A") expenses were \$4.15/boe and \$3.65/boe for the three and six months ended June 30, 2018, respectively, compared to \$5.02/boe and \$5.59/boe for the comparative periods in 2017. G&A expenses in the first half of 2018 were consistent to the comparative periods in 2017 but decreased on a per boe basis due to increased production in 2018.

SHARE BASED COMPENSATION	Three Months Ended June 30			Six Months Ended June 30		
	2018	2017	% Change	2018	2017	% Change
Share based compensation (\$000s)	2,641	401	559	2,912	781	273
Share based compensation (\$/boe)	8.32	1.68	395	4.20	1.91	120

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

Share based compensation expense increased to \$2.6 million and \$2.9 million for the three and six months ended June 30, 2018, respectively, compared to \$0.4 million and \$0.8 million for the comparative periods in 2017. In May 2018, the expiry term for previously granted stock options, performance warrants and purchase warrants was extended to 6 years from the original term of 4 or 5 years. The incremental fair value of the modifications was \$3.8 million and \$3.1 million was recognized during the three months ended June 30, 2018 based on the percentage of modified awards that were vested as at May 30, 2018 with the remaining expense to be recognized ratably as the awards vest. The incremental fair value was estimated immediately before and as at the date of modification using a Black-Scholes-Merton option pricing model.

FINANCE EXPENSE (\$000s)	Three Months Ended June 30			Six Months Ended June 30		
	2018	2017	% Change	2018	2017	% Change
Interest expense	30	38	(21)	44	40	10
Accretion of decommissioning obligations	51	38	34	97	76	28
Finance expense	81	76	7	141	116	22
Finance expense (\$/boe)	0.26	0.32	(19)	0.20	0.28	(29)

Interest expense during the first half of 2018 remained consistent with the comparable period of 2017.

Accretion expense has increased for the three and six months ended June 30, 2018 compared to the same periods in 2017 due to drilling activity adding more wells.

#### FINANCE INCOME

For the three and six months ended June 30, 2018, finance income totaled \$0.1 million and \$0.2 million, respectively, consistent with \$0.1 million and \$0.2 million for the comparative periods in 2017. Finance income relates to interest earned on cash in the bank.

#### 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 June 30, 2018 total approximately \$308.6 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:

(\$000s)	Three Months Ended June 30			Six Months Ended June 30		
	2018	2017	% Change	2018	2017	% Change
Cash flow from operating activities	4,579	3,384	35	10,510	3,695	184
Add (deduct):						
Decommissioning expenditures	94	-	100	94	-	100
Change in non-cash working capital	(1,325)	(1,287)	3	(869)	(302)	188
Adjusted funds flow (non-GAAP)	3,348	2,097	60	9,735	3,393	187

Adjusted funds flow was \$3.3 million (\$0.02 per basic and diluted share) and \$9.7 million (\$0.05 per basic and diluted share) for the three and six months ended June 30, 2018, respectively, compared to \$2.1 million (\$0.01 per basic and diluted share) and \$3.4 million (\$0.02 per basic and diluted share) for the comparative periods in 2017. The increase was mainly the result of production growth from successful drilling at Doe/Mica, higher oil and NGLs commodity prices, and royalty credits from BC's IRCP, partially offset by significantly lower natural gas prices.

Cash flow from operations increased for the three and six months ended June 30, 2018 to \$4.6 million (\$0.02 per basic and diluted share) and \$10.5 million (\$0.05 per basic and diluted share), respectively, from \$3.4 million (\$0.02 per basic and diluted share) and \$3.7 million (\$0.02 per basic and diluted share) for the comparative periods in 2017. Consistent with adjusted funds flow, the increase was mainly the result of production growth from successful drilling at Doe/Mica, higher oil and NGLs commodity prices, and royalty credits from BC's IRCP, partially offset by significantly lower natural gas prices. 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 loss for the three months ended June 30, 2018 was \$2.3 million (\$0.01 per basic and diluted share) compared to \$0.7 million (\$nil per basic and diluted share) for the comparative period in 2017. For the six months ended June 30, 2018, the Company had net



earnings of \$0.3 million (\$nil per basic and diluted share) compared to a net loss of \$1.6 million (\$0.01 per basic and diluted share) for the comparative period in 2017.

Despite the aforementioned increase in oil and natural gas sales and adjusted funds flow, net earnings in 2018 were negatively impacted by non-cash share based compensation expense related to the expiry term extension of existing stock options, performance warrants and purchase warrants.

CAPITAL EXPENDITURES (\$000s)	Three Months Ended June 30			Six Months Ended June 30		
	2018	2017	% Change	2018	2017	% Change
Property acquisitions (net)	-	31,915	(100)	-	35,550	(100)
Land	193	908	(79)	1,030	1,142	(10)
Drilling, completions, and workovers	984	5,194	(81)	9,092	10,485	(13)
Equipment	1,045	4,507	(77)	3,409	13,410	(75)
Geological and geophysical	178	286	(38)	304	741	(59)
Office equipment	-	-	-	25	-	100
<b>Total expenditures</b>	<b>2,400</b>	<b>42,810</b>	<b>(94)</b>	<b>13,860</b>	<b>61,328</b>	<b>(77)</b>

During the first half 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 half of 2017 the Company completed its Mica 12-06 well drilled in Q4 2016 and drilled and completed an offset well to Mica 8-22 (A8-22). 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) and substantially completed the tie-in of Mica 8-4. The Company also 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. There were no reserves attached to any of the net acquisition lands.

## LIQUIDITY AND CAPITAL RESOURCES

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

(\$000s)	June 30, 2018	December 31, 2017	% Change
Current assets	18,000	29,224	(38)
Less:			
Current liabilities	(3,533)	(10,564)	(67)
<b>Working capital</b>	<b>14,467</b>	<b>18,660</b>	<b>(22)</b>

At June 30, 2018, the Company had working capital of \$14.5 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 June 30, 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 \$7.1 million of securities of Leucrotta common shares and a margin payable of \$1.0 million. The cross-guarantee is not intended to be long-term 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 June 30, 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 June 30, 2018:

(\$000s)	Total	Less than One Year	One to Three Years	After Three Years
Accounts payable and accrued liabilities	3,533	3,533	-	-
Decommissioning obligations	9,353	-	-	9,353
Office leases	1,067	320	640	107
Firm transportation agreements	16,749	6,373	10,376	-
<b>Total contractual obligations</b>	<b>30,702</b>	<b>10,226</b>	<b>11,016</b>	<b>9,460</b>

Transportation commitments include contracts to transport natural gas and NGLs through third-party owned pipeline systems. The Company currently has commitments of 18 mmcf/d escalating to 33.3 mmcf/d in 2019.

Subsequent to June 30, 2018, the Company entered into a contract to transport natural gas and NGLs through third party owned pipeline systems for a total commitment of \$1.4 million commencing in November 2018 for a term of 5 months. This commitment has not been reflected in the above table.

#### 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)	June 30, 2018	August 28, 2018
Voting common shares	200,517	200,525
Warrants	15,141	15,135
Stock options	11,435	11,423
Total	227,093	227,083

#### SUMMARY OF QUARTERLY RESULTS

	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017	Q4 2016	Q3 2016
Average Daily Production								
Oil and NGLs (bbls/d)	938	1,144	1,290	857	609	514	234	300
Natural gas (mcf/d)	15,297	18,216	15,071	13,593	12,122	8,197	3,543	4,138
Combined (boe/d)	3,487	4,180	3,802	3,123	2,629	1,881	824	989
(\$000s, except per share amounts)								
Oil and natural gas sales	7,327	10,426	9,301	5,723	6,317	4,783	2,233	2,264
Adjusted funds flow	3,348	6,387	4,462	1,747	2,097	1,296	(98)	(124)
Per share - basic and diluted	0.02	0.03	0.02	0.01	0.01	0.01	-	-
Net earnings (loss)	(2,280)	2,546	(5,072)	(1,549)	(723)	(878)	(1,657)	(4,994)
Per share - basic and diluted	(0.01)	0.01	(0.03)	(0.01)	-	(0.01)	(0.01)	(0.03)

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

#### 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:

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

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

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

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

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

The Company applied IFRS 15 to all of its contracts with customers using the modified retrospective method. Management reviewed the Company's revenue streams and major contracts with customers using the IFRS 15 principles-based five-step model and concluded that there were no material changes to earnings or timing of when production revenue is recognized. However, it was determined that certain transactions in respect of third party marketing arrangements that optimized the Company's transportation capacity were previously presented net within transportation expenses have been reclassified and presented separately in the 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 June 30, 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 June 30, 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 June 30, 2018, \$2.2 million (98%) 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 June 30, 2018, the Company did not deem any outstanding accounts receivable to be uncollectable (June 30, 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 \$14.5 million including \$14.5 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.

### **TEST RATES**

The A10-08-83-16W6 well was production tested for 6 days after the original cleanup and produced at an average rate of 1,100 boe/d (48% gas, 52% Oil and Condensate) over that period, excluding load fluid and energizing fluid. At the end of the test, flowing wellhead pressure and production rates were stable.

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

### **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](http://www.sedar.com).

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

(\$000s)	Note	June 30 2018	December 31 2017
<b>Assets</b>			
Current assets			
Cash and cash equivalents		14,534	23,747
Restricted cash		1,000	1,000
Accounts receivable		2,235	4,104
Prepaid expenses and deposits		231	373
		<b>18,000</b>	29,224
Property, plant, and equipment	(4)	154,259	156,395
Exploration and evaluation assets	(5)	138,453	127,422
		<b>292,712</b>	283,817
		<b>310,712</b>	313,041
<b>Liabilities</b>			
Current liabilities			
Accounts payable and accrued liabilities		3,533	10,564
Decommissioning obligations	(7)	9,353	8,718
		<b>12,886</b>	19,282
<b>Shareholders' Equity</b>			
Shareholders' capital	(8)	288,824	288,787
Contributed surplus		18,162	14,398
Deficit		(9,160)	(9,426)
		<b>297,826</b>	293,759
		<b>310,712</b>	313,041
Commitments and subsequent event	(14)		

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

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

(\$000s, except per share amounts)	Note	Three Months Ended June 30		Six Months Ended June 30	
		2018	2017	2018	2017
<b>Revenue</b>					
Oil and natural gas sales	(12)	<b>7,327</b>	6,317	<b>17,753</b>	11,100
Processing and marketing	(12)	<b>623</b>	70	<b>1,021</b>	1,309
Royalties	(12)	<b>(65)</b>	(558)	<b>(65)</b>	(827)
		<b>7,885</b>	5,829	<b>18,709</b>	11,582
<b>Expenses</b>					
Operating		<b>2,197</b>	1,508	<b>4,375</b>	2,850
Transportation and marketing	(13)	<b>1,071</b>	1,097	<b>2,199</b>	3,218
Depletion and depreciation	(4)	<b>2,936</b>	2,381	<b>6,460</b>	4,137
General and administrative		<b>1,318</b>	1,202	<b>2,533</b>	2,284
Share based compensation	(9)	<b>2,641</b>	401	<b>2,912</b>	781
Finance income		<b>(79)</b>	(113)	<b>(177)</b>	(203)
Finance expense		<b>81</b>	76	<b>141</b>	116
		<b>10,165</b>	6,552	<b>18,443</b>	13,183
Net (loss) earnings and comprehensive (loss) earnings		<b>(2,280)</b>	(723)	<b>266</b>	(1,601)
Net (loss) earnings per share					
Basic and diluted	(10)	<b>(0.01)</b>	-	-	(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	-	-	(1,601)	(1,601)
Issue of shares (net of share issue costs and flow-through share premium)	74,780	-	-	74,780
Exercise of warrants and stock options	106	(30)	-	76
Share based compensation	-	974	-	974
<b>Balance, June 30, 2017</b>	<b>288,761</b>	<b>13,437</b>	<b>(2,805)</b>	<b>299,393</b>
Balance, December 31, 2017	288,787	14,398	(9,426)	293,759
Net earnings	-	-	266	266
Exercise of stock options	37	(11)	-	26
Share based compensation	-	3,775	-	3,775
<b>Balance, June 30, 2018</b>	<b>288,824</b>	<b>18,162</b>	<b>(9,160)</b>	<b>297,826</b>

*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 June 30		Six Months Ended June 30	
		2018	2017	2018	2017
<b>Operating Activities</b>					
Net (loss) earnings		<b>(2,280)</b>	(723)	<b>266</b>	(1,601)
Depletion and depreciation	(4)	<b>2,936</b>	2,381	<b>6,460</b>	4,137
Share based compensation	(9)	<b>2,641</b>	401	<b>2,912</b>	781
Finance expense		<b>81</b>	76	<b>141</b>	116
Interest paid		<b>(30)</b>	(38)	<b>(44)</b>	(40)
Decommissioning expenditures	(7)	<b>(94)</b>	-	<b>(94)</b>	-
Change in non-cash working capital	(11)	<b>1,325</b>	1,287	<b>869</b>	302
		<b>4,579</b>	3,384	<b>10,510</b>	3,695
<b>Financing Activities</b>					
Issue of shares		-	80,001	-	80,001
Share issue costs		-	(4,388)	-	(4,388)
Exercise of warrants and stock options		-	28	<b>26</b>	76
		-	75,641	<b>26</b>	75,689
<b>Investing Activities</b>					
Capital expenditures - property, plant, and equipment	(4)	<b>(749)</b>	(9,339)	<b>(3,526)</b>	(20,721)
Capital expenditures - exploration and evaluation assets	(5)	<b>(1,651)</b>	(1,556)	<b>(10,334)</b>	(5,057)
Property acquisitions (net)		-	(31,915)	-	(35,550)
Change in non-cash working capital	(11)	<b>(3,532)</b>	(337)	<b>(5,889)</b>	(1,210)
		<b>(5,932)</b>	(43,147)	<b>(19,749)</b>	(62,538)
Change in cash and cash equivalents		<b>(1,353)</b>	35,878	<b>(9,213)</b>	16,846
Cash and cash equivalents, beginning of period		<b>15,887</b>	13,965	<b>23,747</b>	32,997
Cash and cash equivalents, end of period		<b>14,534</b>	49,843	<b>14,534</b>	49,843

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

**Leucrotta Exploration Inc.**  
**Notes to the Condensed Interim Financial Statements**  
**Three and Six Months Ended June 30, 2018**  
(unaudited)

*(Tabular amounts in 000s, unless otherwise stated)*

**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 – 5<sup>th</sup> 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 August 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:

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

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

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

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

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

The Company applied IFRS 15 to all of its contracts with customers using the modified retrospective method. Management reviewed the Company's revenue streams and major contracts with customers using the IFRS 15 principles-based five-step model and concluded that there were no material changes to earnings or timing of when production revenue is recognized. However, it was determined that certain transactions in respect of third party marketing arrangements that optimized the Company's transportation capacity were previously presented net within transportation expenses have been reclassified and presented separately in the 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

<b>Cost</b>	<b>Total</b>
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	<b>3,526</b>
Change in decommissioning obligations	<b>632</b>
Capitalized share based compensation	<b>166</b>
<b>Balance, June 30, 2018</b>	<b>196,402</b>
<b>Accumulated Depletion, Depreciation, and Impairment</b>	<b>Total</b>
Balance, December 31, 2016	25,809
Depletion and depreciation	10,212
Dispositions	(338)
Balance, December 31, 2017	35,683
Depletion and depreciation	<b>6,460</b>
<b>Balance, June 30, 2018</b>	<b>42,143</b>
<b>Net Book Value</b>	<b>Total</b>
December 31, 2017	156,395
<b>June 30, 2018</b>	<b>154,259</b>

During the three and six months ended June 30, 2018, \$nil (June 30, 2017 - \$0.1 million) and \$0.1 million (June 30, 2017 - \$0.3 million), 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 June 30, 2018 included an estimated \$166.1 million (June 30, 2017 - \$79.9 million) for future development costs associated with proved plus probable undeveloped reserves and excluded approximately \$3.7 million (June 30, 2017 - \$3.5 million) for the estimated salvage value of production equipment and facilities.

#### 5. EXPLORATION AND EVALUATION ASSETS

	<b>Total</b>
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	<b>10,334</b>
Capitalized share based compensation	<b>697</b>
<b>Balance, June 30, 2018</b>	<b>138,453</b>

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 and six months ended June 30, 2018, approximately \$nil (June 30, 2017 - \$nil) and \$0.1 million (June 30, 2017 - \$nil), respectively, 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 June 30, 2018, \$nil had been drawn on the revolving credit facility. At June 30, 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 June 30, 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 \$15.6 million (December 31, 2017 - \$14.7 million) which is estimated to be incurred over the next 32 years. At June 30, 2018, a risk-free rate of 2.15% (December 31, 2017 - 2.15%) was used to calculate the net present value of the decommissioning obligations.

	Six Months Ended June 30, 2018	Year Ended December 31, 2017
Balance, beginning of period	8,718	6,820
Provisions incurred	409	1,604
Provisions settled	(94)	(296)
Dispositions	-	(239)
Revisions in estimated cash flows	214	435
Revisions due to change of discount rates	9	232
Accretion	97	162
<b>Balance, end of period</b>	<b>9,353</b>	<b>8,718</b>

## 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
<b>Balance, June 30, 2018</b>	<b>200,517</b>	<b>288,824</b>

## 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 June 30, 2018, 11.4 million options were outstanding at an average exercise price of \$1.25 per share.

	Number of Options	Weighted Average Exercise Price (\$)
Balance, December 31, 2016	8,920	1.09
Granted	2,626	1.78
Exercised	(76)	1.09
Balance, December 31, 2017	11,470	1.25
Granted	25	1.70
Exercised	(20)	1.29
Forfeited	(40)	1.47
<b>Balance, June 30, 2018</b>	<b>11,435</b>	<b>1.25</b>
<b>Exercisable, June 30, 2018</b>	<b>7,391</b>	<b>1.13</b>

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:

	Six Months Ended June 30	
	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	-

During the three and six months ended June 30, 2018, the Company recognized \$1.6 million (June 30, 2017 - \$0.2 million) and \$1.9 million (June 30, 2017 - \$0.4 million), respectively, of share based compensation related to the stock options (including the stock option modification, see below). At June 30, 2018 there was \$1.4 million remaining as unrecognized share based compensation related to both the original stock option grants and the modification incremental fair value.

#### Stock option modification

In May 2018, the expiry term for previously granted stock options was extended to 6 years from the original term of 4 or 5 years. The incremental fair value of the stock option modification was \$1.5 million and \$1.2 million was recognized during the three months ended June 30, 2018 based on the percentage of modified options that were vested. The incremental fair value was estimated immediately before and as at the date of modification using a Black-Scholes-Merton option pricing model with the following weighted average assumptions:

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

#### Performance Warrants

	Number of Warrants	Exercise Price
Balance, December 31, 2016	7,500	1.70
Exercised	(9)	1.70
<b>Balance, December 31, 2017 and June 30, 2018</b>	<b>7,491</b>	<b>1.70</b>
<b>Exercisable, June 30, 2018</b>	<b>4,491</b>	<b>1.70</b>

During the three and six months ended June 30, 2018, the Company recognized \$0.6 million (June 30, 2017 - \$0.1 million) and \$0.6 million (June 30, 2017 - \$0.3 million), respectively, of share based compensation related to the performance warrants (including the performance warrant modification, see below). At June 30, 2018 there was \$0.4 million remaining as unrecognized share based compensation related to the performance warrant modification incremental fair value.

### Performance warrant modification

In May 2018, the expiry term for previously granted performance warrants was extended to 6 years from the original term of 5 years. The incremental fair value of the performance warrant modification was \$1.0 million and \$0.6 million was recognized during the three months ended June 30, 2018 based on the percentage of modified performance warrants that were vested. The incremental fair value was estimated immediately before and as at the date of modification using a Black-Scholes-Merton option pricing model with the following weighted average assumptions:

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

### Purchase Warrants

The Company has 7.65 million purchase warrants outstanding to certain officers, directors, employees, and consultants to purchase common shares at an exercise price of \$2.04 expiring on September 12, 2020 vesting equally over three years.

	Number of Warrants	Exercise Price
<b>Balance, December 31, 2016 and 2017 and June 30, 2018</b>	<b>7,650</b>	<b>2.04</b>
<b>Exercisable, June 30, 2018</b>	<b>7,650</b>	<b>2.04</b>

During the three and six months ended June 30, 2018, the Company recognized \$1.3 million (June 30, 2017 - \$0.1 million) and \$1.3 million (June 30, 2017 - \$0.3 million), respectively, of share based compensation related to the purchase warrants. At June 30, 2018 there was \$nil remaining as unrecognized share based compensation related to the purchase warrants.

### Purchase warrant modification

In May 2018, the expiry term for previously granted purchase warrants was extended to 6 years from the original term of 5 years. The incremental fair value of the purchase warrant modification was \$1.3 million and \$1.3 million was recognized during the three months ended June 30, 2018 based on the percentage of modified purchase warrants that were vested. The incremental fair value was estimated immediately before and as at the date of modification using a Black-Scholes-Merton option pricing model with the following weighted average assumptions:

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

## 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 June 30		Six Months Ended June 30	
	2018	2017	2018	2017
Weighted average number of shares - basic	200,517	190,795	200,517	178,087
Dilutive effect of share based compensation plans	-	-	3,216	-
Weighted average number of shares - diluted	200,517	190,795	203,733	178,087

For the three months ended June 30, 2018, 11.4 million stock options (June 30, 2017 - 8.9 million), 7.7 million purchase warrants (June 30, 2017 - 7.7 million) and 7.5 million performance warrants (June 30, 2017 - 7.5 million) were anti-dilutive due to the net loss.

For the six months ended June 30, 2018, 2.6 million stock options (June 30, 2017 - 8.9 million), 7.7 million purchase warrants (June 30, 2017 - 7.7 million) and 7.5 million performance warrants (June 30, 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 June 30		Six Months Ended June 30	
	2018	2017	2018	2017
Accounts receivable	1,410	1,016	1,869	(567)
Prepaid expenses and deposits	63	48	142	74
Accounts payable and accrued liabilities	(3,680)	(114)	(7,031)	(415)
Change in non-cash working capital	(2,207)	950	(5,020)	(908)
Relating to:				
Investing	(3,532)	(337)	(5,889)	(1,210)
Operating	1,325	1,287	869	302
Change in non-cash working capital	(2,207)	950	(5,020)	(908)

## 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 June 30		Six Months Ended June 30	
	2018	2017	2018	2017
Oil and condensate	4,503	2,585	9,821	4,971
Other natural gas liquids	1,052	402	2,127	693
Natural gas	1,772	3,330	5,805	5,436
Oil and natural gas sales	7,327	6,317	17,753	11,100

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 June 30		Six Months Ended June 30	
	2018	2017	2018	2017
Natural gas production sales	1,072	2,486	4,305	3,762
Transportation revenue	700	844	1,500	1,674
Natural gas sales	1,772	3,330	5,805	5,436

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

	Three Months Ended June 30		Six Months Ended June 30	
	2018	2017	2018	2017
Sale of purchased natural gas	295	70	295	1,309
Processing revenue	176	-	422	-
Marketing revenue	152	-	304	-
Processing and marketing revenue	623	70	1,021	1,309

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 95% for the six month period ended June 30, 2018 (June 30, 2017 – 99%).

During the six months ended June 30, 2018, the Company began receiving credits to offset royalties from the British Columbia Government's Infrastructure Royalty Credit Program resulting from infrastructure built in 2017 and wells drilled and tied-into the

related infrastructure. During the three and six months ended June 30, 2018, the Company realized credits of \$0.6 million and \$1.4 million, respectively, to offset royalties payable.

### 13. TRANSPORTATION AND MARKETING EXPENSES

	Three Months Ended June 30		Six Months Ended June 30	
	2018	2017	2018	2017
Pipeline tariffs from firm transportation agreements	866	1,043	1,994	2,078
Purchased natural gas	205	54	205	1,140
Transportation and marketing expenses	1,071	1,097	2,199	3,218

### 14. COMMITMENTS

The following is a summary of the Company's contractual obligations and commitments at June 30, 2018:

	2018	2019	2020	2021	2022	Thereafter	Total
Office leases	160	320	320	267	-	-	1,067
Firm transportation agreements	2,426	7,894	6,429	-	-	-	16,749
	2,586	8,214	6,749	267	-	-	17,816

Transportation commitments include contracts to transport natural gas and NGLs through third-party owned pipeline systems. The Company currently has commitments of 18 mmcf/d escalating to 33.3 mmcf/d in 2019.

Subsequent to June 30, 2018, the Company entered into a contract to transport natural gas and NGLs through third party owned pipeline systems for a total commitment of \$1.4 million commencing in November 2018 for a term of 5 months. This commitment has not been reflected in the above table.

# 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.**  
Director

**Tom J. Medvedic, CA**  
Director

## BANK

National Bank of Canada  
1800, 311 – 6th Avenue SW  
Calgary, Alberta T2P 3H2

## TRANSFER AGENT

Computershare  
100 University Avenue, 8th Floor  
Toronto, Ontario M5J 2Y1

## LEGAL COUNSEL

Gowling WLG (Canada) LLP  
1600, 421 – 7th Avenue SW  
Calgary, Alberta T2P 4K9

## AUDITORS

KPMG LLP  
3100, 205 – 5th Avenue SW  
Calgary, Alberta T2P 4B9

## INDEPENDENT ENGINEERS

GLJ Petroleum Consultants Ltd.  
4100, 400 – 3rd Avenue SW  
Calgary, Alberta T2P 4H2



For further information,  
please visit our website at  
[www.leucrotta.ca](http://www.leucrotta.ca) or contact:

**Robert J. Zakresky**  
President & CEO  
P 403.705.4525

**Nolan Chicoine**  
VP Finance & CFO  
P 403.705.4525

**Leucrotta Exploration Inc.**  
Suite 700, 639 – 5th Avenue SW  
Calgary, Alberta T2P 0M9  
P 403.705.4525  
F 403.705.4526

## 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).