WELL POSITIONED

LEUCROTTA
EXPLORATION INC.

ANNUAL REPORT 2016

LEUCROTTA
EXPLORATION INC.

Q4 2016 FINANCIAL AND OPERATING RESULTS

HIGHLIGHTS

- Materially extended the mapping and productive boundaries of the Lower Montney Turbidite Light Oil Resource Play with the drilling of three delineation wells (two horizontal and one vertical).
- Expanded pipeline/infrastructure system in Q4 2016 and into Q1 2017 with four previously drilled wells being put on-stream in Q1 2017.
- Maintained a cash and working capital balance of $26.1 million at December 31, 2016.
- Subsequent to year-end entered into a purchase and sale agreement to acquire certain lands located within the Company's core Doe/Mica area for an aggregate cash purchase price of approximately $36.0 million. The acquisition is expected to close on or about May 31, 2017.
- Subsequent to year-end entered into an agreement with a syndicate of underwriters with respect to an offering of common shares and flow-through common shares by way of a short form prospectus for gross proceeds of $80.0 million (the "Offering"). The Offering is for an aggregate of 33,333,400 common shares at a price of $2.25 per common share and 1,852,000 common shares on a flow-through basis at a price of $2.70 per flow-through common share, closing on April 26, 2017.

	Three Months Ended December 31			Year Ended December 31		
($000s, except per share amounts)	**2016**	2015	% Change	**2016**	2015	% Change
Oil and natural gas sales	**2,281**	2,819	(19)	**8,844**	10,859	(19)
Funds (used in) from operations [(1)]	**(98)**	464	(121)	**(996)**	615	(262)
Per share - basic and diluted	**-**	-	-	**(0.01)**	-	(100)
Net (loss) earnings	**(1,657)**	(15,205)	(89)	**(12,182)**	11,412	(207)
Per share - basic and diluted	**(0.01)**	(0.09)	(89)	**(0.07)**	0.07	(200)
Capital expenditures and acquisitions	**11,718**	29,544	(60)	**22,574**	59,237	(62)
Proceeds from:						
Property dispositions	**-**	-	-	**-**	79,342	(100)
Sale of gas plant equipment	**-**	-	-	**4,000**	-	100
Working capital				**26,063**	45,633	(43)
Common shares outstanding (000s)						
Weighted average - basic and diluted	**165,227**	165,227	-	**165,227**	165,227	-
End of period - basic				**165,227**	165,227	-
End of period - diluted				**189,297**	189,272	-

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

OPERATING RESULTS [1]	**Three Months Ended December 31**			**Year Ended December 31**		
	2016	2015	% Change	**2016**	2015	% Change
Daily production						
Oil and NGLs (bbls/d)	**234**	479	(51)	**317**	316	-
Natural gas (mcf/d)	**3,543**	3,585	(1)	**4,325**	6,112	(29)
Oil equivalent (boe/d)	**824**	1,076	(23)	**1,038**	1,335	(22)
Revenue						
Oil and NGLs ($/bbl)	**53.60**	46.85	14	**45.04**	45.74	(2)
Natural gas ($/mcf)	**3.46**	2.29	51	**2.30**	2.50	(8)
Oil equivalent ($/boe)	**30.08**	28.47	6	**23.35**	22.29	5
Royalties						
Oil and NGLs ($/bbl)	**6.99**	8.90	(21)	**4.69**	6.91	(32)
Natural gas ($/mcf)	**0.16**	0.12	33	**0.06**	0.08	(25)
Oil equivalent ($/boe)	**2.68**	4.37	(39)	**1.67**	1.98	(16)
Production expenses						
Oil and NGLs ($/bbl)	**26.24**	16.58	58	**18.52**	12.58	47
Natural gas ($/mcf)	**1.76**	0.96	83	**1.27**	1.16	9
Oil equivalent ($/boe)	**15.02**	10.56	42	**10.96**	8.29	32
Transportation expenses						
Oil and NGLs ($/bbl)	**6.04**	5.35	13	**5.24**	4.54	15
Natural gas ($/mcf)	**0.47**	0.32	47	**0.44**	0.30	47
Oil equivalent ($/boe)	**3.71**	3.46	7	**3.43**	2.47	39
Operating netback [2]						
Oil and NGLs ($/bbl)	**14.33**	16.02	(11)	**16.59**	21.71	(24)
Natural gas ($/mcf)	**1.07**	0.89	20	**0.53**	0.96	(45)
Oil equivalent ($/boe)	**8.67**	10.08	(14)	**7.29**	9.55	(24)
Depletion and depreciation ($/boe)	**(13.07)**	(52.91)	(75)	**(13.07)**	(17.67)	(26)
Asset impairment ($/boe)	**-**	(83.53)	(100)	**-**	(18.91)	(100)
General and administrative expenses ($/boe)	**(11.08)**	(7.50)	48	**(11.11)**	(9.46)	17
Share based compensation ($/boe)	**(7.11)**	(10.82)	(34)	**(9.36)**	(11.02)	(15)
Finance expenses ($/boe)	**(0.81)**	(0.46)	76	**(0.49)**	(0.49)	-
Finance income ($/boe)	**1.54**	2.26	(32)	**1.35**	1.38	(2)
(Loss) gain on sale of assets ($/boe)	**-**	(3.35)	(100)	**(6.77)**	93.19	(107)
Deferred tax expense ($/boe)	**-**	(7.28)	(100)	**-**	(23.14)	(100)
Net (loss) earnings ($/boe)	**(21.86)**	(153.51)	(86)	**(32.16)**	23.43	(237)

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

(2) Operating netback does not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. Please refer to the "Non-GAAP Measures" section in the MD&A for more details.

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

April 24, 2017

The MD&A should be read in conjunction with the audited financial statements and related notes for the years ended December 31, 2016 and 2015. The audited financial statements and financial data contained in the MD&A have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). All dollar amounts are expressed in Canadian currency, unless otherwise noted.

DESCRIPTION OF BUSINESS

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

FREQUENTLY RECURRING TERMS

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

NON-GAAP MEASURES

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

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

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

UPDATE

In Q4 2016 and early Q1 2017, Leucrotta completed its infrastructure project to tie-in four previously drilled delineation wells and has drilled three additional step-out/delineation wells that materially extend the productive boundaries of the Company's Lower Montney Turbidite Light Oil Resource Play.

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

The three step-out/delineation wells materially extended the productive boundaries of the Lower Montney Turbidite Light Oil Resource Play. The 8-4 well was drilled 5.2 km north and west of the previously drilled 8-22 well. The well encountered light oil in the Lower Montney Turbidite zone and was tested over a 7-day period with an average production of 1,060 boe/d(1). The 12-06 well was drilled 11.7 kms south of the 13-07 oil well and 4.4 kms north of the 13-19 liquids-rich gas well. The well encountered oil pay and was tested over a 7-day period with average production of 550 boe/d(1). The third step-out /delineation well was a vertical stratigraphic test drilled at 4-30 north of the Peace River. Located 7.4 km northwest of the 8-4 well, the well was logged and cored in the Upper, Middle and Lower Montney. The well encountered 55 metres of pay in the Lower Montney with core porosities on par with the core porosities in the 13-7 well. The 4-30 vertical well confirms the geological mapping and oil charge of a major northern extension of the Lower Montney Turbidite Light Oil Resource Play. Analysis of Upper and Middle Montney in the 4-30 wellbore showed potential as exploratory future targets.

Subsequent to year-end, Leucrotta signed agreements to acquire an additional 18.5 sections of land located in its core Doe/Mica Montney area and initiated a bought-deal financing for gross proceeds of $80 million to fund the acquisition and a portion of the future capital programs. Leucrotta has estimated that it will have approximately $50 million of cash and no debt on completion of the financing and funding the land acquisitions.

On a go forward basis, Leucrotta will continue its capital program focused primarily on the delineation and development of its Doe/Mica core area.

(1) See "Test Results and Production Rates" section for more details.

SUMMARY OF FINANCIAL RESULTS

	Three Months Ended December 31		Year Ended December 31		
($000s, except per share amounts)	**2016**	2015	**2016**	2015	2014
Oil and natural gas sales	**2,281**	2,819	**8,844**	10,859	29,322
Funds (used in) from operations	**(98)**	464	**(996)**	615	15,210
Per share - basic and diluted	**-**	-	**(0.01)**	-	0.12
Net (loss) earnings	**(1,657)**	(15,205)	**(12,182)**	11,412	3,090
Per share - basic and diluted	**(0.01)**	(0.09)	**(0.07)**	0.07	0.02
Total assets			**241,635**	253,038	242,784
Total long-term liabilities			**6,820**	6,673	7,286
Working capital			**26,063**	45,633	25,003

The Company experienced a reduction in oil and natural gas sales and funds (used in) from operations for the three months ended December 31, 2016 compared to the same period in 2015 due to natural declines in production. The significant net loss in Q4 2015 was the result of impairment on the Company's non-Montney assets.

For the year ended December 31, 2016, oil and natural gas sales and funds (used in) from operations decreased from 2015 mainly due to natural declines in production and from the sale of certain oil and natural gas properties in Q2 2015 resulting in lower production for 2016. Both years ended December 31, 2016 and 2015 saw large decreases in oil and natural gas sales and funds (used in) from operations from 2014 due to a significant decline in oil, NGLs, and natural gas commodity prices from 2014 through 2015 and 2016 and from the sale of certain oil and natural gas properties in Q2 2015 resulting in lower production for both 2016 and 2015 compared to 2014.

The significant net earnings in the year ended December 31, 2015 compared to the net loss in 2016 and lower net earnings in 2014 was mainly the result of the significant gain on the sale of oil and gas properties and equipment which was partially offset by impairment charges on non-Montney assets.

The decrease in working capital is mainly the result of capital expenditures during 2016.

PRODUCTION	Three Months Ended December 31			Year Ended December 31		
	2016	2015	% Change	**2016**	2015	% Change
Average Daily Production						
Oil and NGLs (bbls/d)	**234**	479	(51)	**317**	316	-
Natural gas (mcf/d)	**3,543**	3,585	(1)	**4,325**	6,112	(29)
Combined (boe/d)	**824**	1,076	(23)	**1,038**	1,335	(22)

Daily production for the fourth quarter of 2016 decreased 23% to 824 boe/d from 1,076 boe/d for the comparative quarter in 2015 due to natural declines. Year-to-date production decreased 22% to 1,038 boe/d in 2016 from 1,335 boe/d in 2015 due to natural declines as well as the sale of oil and natural gas properties in Northeast BC (producing approximately 1,300 boe/d at the time of sale) in Q2 2015. Production volumes are expected to increase in Q1 2017 to an average of approximately 1,800 boe/d with the tie-in of four previously drilled Montney wells in February and March. These wells include 2 Liquids-rich Lower Montney Turbidite gas wells, 1 Lower Montney Turbidite oil well, and 1 Liquids-rich Upper Montney gas well.

Leucrotta's production profile for the fourth quarter of 2016 saw a decrease in liquids weighting from the fourth quarter of 2015. The Q4 2016 weighting was 72% natural gas (2015 - 55%) and 28% oil and NGLs (2015 - 45%). The high liquids weighting in Q4 2015 was influenced by new light oil production from Mica and Stoddart that had flush production and has since declined.

Year-to-date, Leucrotta's production profile for 2016 saw an increase in liquids weighting over 2015 due to the sale of certain oil and natural gas properties during Q2 2015 which were gas weighted and also new light oil production from Mica and Stoddart. The 2016 weighting was 69% natural gas (2015 - 76%) and 31% oil and NGLs (2015 - 24%).

REVENUE	Three Months Ended December 31			Year Ended December 31		
($000s)	**2016**	2015	% Change	**2016**	2015	% Change
Oil and NGLs	**1,152**	2,064	(44)	**5,209**	5,279	(1)
Natural gas	**1,129**	755	50	**3,635**	5,580	(35)
Total	**2,281**	2,819	(19)	**8,844**	10,859	(19)
Average Sales Price						
Oil and NGLs ($/bbl)	**53.60**	46.85	14	**45.04**	45.74	(2)
Natural gas ($/mcf)	**3.46**	2.29	51	**2.30**	2.50	(8)
Combined ($/boe)	**30.08**	28.47	6	**23.35**	22.29	5

Revenue totaled $2.3 million for the fourth quarter of 2016, down 19% from $2.8 million for the comparative quarter in 2015. For the year ended December 31, 2016, revenue decreased 19% to $8.8 million from $10.9 million for 2015. The decrease in revenue was due to declines in production partially offset by marginally stronger oil, NGLs, and natural gas commodity prices.

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

Commodity Pricing	**Three Months Ended December 31**			**Year Ended December 31**		
	2016	2015	% Change	**2016**	2015	% Change
Oil and NGLs						
Corporate price ($CDN/bbl)	**53.60**	46.85	14	**45.04**	45.74	(2)
Canadian light sweet ($CDN/bbl)	**60.76**	52.55	16	**52.80**	57.45	(8)
West Texas Intermediate ("WTI") ($US/bbl)	**49.29**	42.18	17	**43.32**	48.80	(11)
Natural gas						
Corporate price ($CDN/mcf)	**3.46**	2.29	51	**2.30**	2.50	(8)
AECO price ($CDN/mcf)	**3.11**	2.48	25	**2.18**	2.70	(19)
Exchange rate						
$US/$CAD exchange rate	**0.7492**	0.7492	-	**0.7553**	0.7834	(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.

The Company's corporate average oil and NGLs prices were 88.2% and 85.3% of Canadian light sweet prices for the three months and year ended December 31, 2016, respectively, compared to 89.2% and 79.6% for the comparative periods in 2015.

Corporate average natural gas prices were 111.3% and 105.5% of AECO prices for the three months and year ended December 31, 2016, respectively, up from 92.3% and 92.6% for the comparative periods in 2015. The increase in the Company's corporate natural gas price compared to AECO was due to having a larger portion of the Company's natural gas sales in 2015 priced on an interruptible basis off indexes other than AECO. This pricing issue was alleviated in Q4 2015 with new firm transportation and pricing contracts.

Leucrotta's liquids mix during the fourth quarter of 2016 was approximately 81% light oil, condensate and pentanes, 7% butane and 12% propane which was consistent with Q4 2015.

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

ROYALTIES	**Three Months Ended December 31**			**Year Ended December 31**		
($000s)	**2016**	2015	% Change	**2016**	2015	% Change
Oil and NGLs	**150**	392	(62)	**542**	797	(32)
Natural gas	**53**	41	29	**92**	168	(45)
Total	**203**	433	(53)	**634**	965	(34)
Average Royalty Rate (% of sales)						
Oil and NGLs	**13.0**	19.0	(32)	**10.4**	15.1	(31)
Natural gas	**4.7**	5.4	(13)	**2.5**	3.0	(17)
Combined	**8.9**	15.4	(42)	**7.2**	8.9	(19)

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

For the fourth quarter of 2016, oil, NGLs, and natural gas royalties totaled $0.2 million (8.9% of revenue) compared to $0.4 million (15.4% of revenue) for the comparative quarter in 2015. For the year ended December 31, 2016, oil, NGLs, and natural gas royalties totaled $0.6 million (7.2% of revenue) compared to $1.0 million (8.9% of revenue) for 2015.

Oil and NGLs royalties have decreased to 13.0% and 10.4% for the three months and year ended December 31, 2016, respectively, from 19.0% and 15.1% in the comparative periods in 2015. The decrease in oil and NGLs royalties is due to higher royalty properties being divested and shut-in in Q4 2015 and also due to deep gas royalty credits on new natural gas wells which also affects royalties for NGLs on those wells.

Natural gas royalties have slightly decreased to 4.7% and 2.5% for the three months and year ended December 31, 2016, respectively, compared to 5.4% and 3.0% in the comparative periods in 2015. The decrease is due to deep gas royalty credits on new natural gas wells.

PRODUCTION EXPENSES	**Three Months Ended December 31**			**Year Ended December 31**		
($000s)	**2016**	2015	% Change	**2016**	2015	% Change
Oil and NGLs	**564**	731	(23)	**2,142**	1,452	48
Natural gas	**575**	315	83	**2,007**	2,589	(22)
Total	**1,139**	1,046	9	**4,149**	4,041	3
Average expense						
Oil and NGLs ($/bbl)	**26.24**	16.58	58	**18.52**	12.58	47
Natural gas ($/mcf)	**1.76**	0.96	83	**1.27**	1.16	9
Combined ($/boe)	**15.02**	10.56	42	**10.96**	8.29	32

Per unit production expenses increased to $15.02/boe and $10.96/boe for the three months and year ended December 31, 2016, respectively, from $10.56/boe and $8.29/boe in the comparative periods in 2015. The increase in oil and NGLs production expenses for the year was mainly due to new light oil production from Mica and Stoddart which carries higher production expenses due to water handling and disposal, emulsion hauling and treating, and other normal costs associated with the production of oil. The increase was also due to the sale of oil and natural gas properties during the second quarter of 2015 which lowered overall production and also left a larger percentage of higher-cost properties within the Company. The large increase in production expenses per boe in Q4 2016 over both Q4 2015 and Q3 2016 ($11.12/boe) was due to the reduction in 3rd party volumes at its Doe gas plant which bore a portion of the plant's fixed costs. This will be mitigated in Q1 2017 with increased production volumes of the Company after the tie-in of its own previously drilled wells during February and March. The actual cost increase was very minimal being $0.1 million (9%) for Q4 2016 over Q4 2015 and $0.1 million (3%) for the year 2016 over 2015.

TRANSPORTATION EXPENSES	**Three Months Ended December 31**			**Year Ended December 31**		
($000s)	**2016**	2015	% Change	**2016**	2015	% Change
Oil and NGLs	**130**	236	(45)	**607**	523	16
Natural gas	**152**	107	42	**694**	680	2
Total	**282**	343	(18)	**1,301**	1,203	8
Average expense						
Oil and NGLs ($/bbl)	**6.04**	5.35	13	**5.24**	4.54	15
Natural gas ($/mcf)	**0.47**	0.32	47	**0.44**	0.30	47
Combined ($/boe)	**3.71**	3.46	7	**3.43**	2.47	39

Transportation expenses are mainly third-party pipeline tariffs incurred to deliver production to the purchasers at main hubs. Transportation costs increased to $3.71/boe and $3.43/boe for the three months and year ended December 31, 2016, respectively, compared to $3.46/boe and $2.47/boe for the comparative periods in 2015. While Q4 2016 was consistent with Q4 2015, the increase for year-to-date 2016 over 2015 was mainly due to transportation costs associated with new light oil production from Mica and Stoddart and also the sale of oil and natural gas properties during the second quarter of 2015 which yielded very low transportation costs.

OPERATING NETBACK	**Three Months Ended December 31**			**Year Ended December 31**		
	2016	2015	% Change	**2016**	2015	% Change
Oil and NGLs ($/bbl)						
Revenue	**53.60**	46.85	14	**45.04**	45.74	(2)
Royalties	**(6.99)**	(8.90)	(21)	**(4.69)**	(6.91)	(32)
Production expenses	**(26.24)**	(16.58)	58	**(18.52)**	(12.58)	47
Transportation expenses	**(6.04)**	(5.35)	13	**(5.24)**	(4.54)	15
Operating netback	**14.33**	16.02	(11)	**16.59**	21.71	(24)
Natural gas ($/mcf)						
Revenue	**3.46**	2.29	51	**2.30**	2.50	(8)
Royalties	**(0.16)**	(0.12)	33	**(0.06)**	(0.08)	(25)
Production expenses	**(1.76)**	(0.96)	83	**(1.27)**	(1.16)	9
Transportation expenses	**(0.47)**	(0.32)	47	**(0.44)**	(0.30)	47
Operating netback	**1.07**	0.89	20	**0.53**	0.96	(45)
Combined ($/boe)						
Revenue	**30.08**	28.47	6	**23.35**	22.29	5
Royalties	**(2.68)**	(4.37)	(39)	**(1.67)**	(1.98)	(16)
Production expenses	**(15.02)**	(10.56)	42	**(10.96)**	(8.29)	32
Transportation expenses	**(3.71)**	(3.46)	7	**(3.43)**	(2.47)	39
Operating netback	**8.67**	10.08	(14)	**7.29**	9.55	(24)

During the three months and year ended December 31, 2016, Leucrotta generated an operating netback of $8.67/boe and $7.29/boe, respectively, down significantly from $10.08/boe and $9.55/boe for the comparative periods in 2015. The decrease was mainly due to increased production expenses and transportation costs resulting from higher costs associated with new light oil production in Mica and Stoddart, the sale of oil and natural gas properties during the second quarter of 2015 which yielded lower costs and also the reduction in 3rd party volumes at its Doe gas plant which bore a portion of the plant's fixed costs.

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

	Three Months Ended December 31			Year Ended December 31		
($/boe)	**2016**	2015	% Change	**2016**	2015	% Change
Operating netback	**8.67**	10.08	(14)	**7.29**	9.55	(24)
Depletion and depreciation	**(13.07)**	(52.91)	(75)	**(13.07)**	(17.67)	(26)
Asset impairment	**-**	(83.53)	(100)	**-**	(18.91)	(100)
General and administrative expenses	**(11.08)**	(7.50)	48	**(11.11)**	(9.46)	17
Share based compensation	**(7.11)**	(10.82)	(34)	**(9.36)**	(11.02)	(15)
Finance expenses	**(0.81)**	(0.46)	76	**(0.49)**	(0.49)	-
Finance income	**1.54**	2.26	(32)	**1.35**	1.38	(2)
(Loss) gain on sale of assets	**-**	(3.35)	(100)	**(6.77)**	93.19	(107)
Deferred tax recovery (expense)	**-**	(7.28)	(100)	**-**	(23.14)	(100)
Net (loss) earnings (GAAP)	**(21.86)**	(153.51)	(86)	**(32.16)**	23.43	(237)

DEPLETION AND DEPRECIATION	Three Months Ended December 31			Year Ended December 31		
	2016	2015	% Change	**2016**	2015	% Change
Depletion and depreciation ($000s)	**991**	5,239	(81)	**4,951**	8,607	(42)
Depletion and depreciation ($/boe)	**13.07**	52.91	(75)	**13.07**	17.67	(26)

The Company calculates depletion on property, plant, and equipment mainly based on proved plus probable reserves. Some facilities in Stoddart and certain gas plant equipment, where the production and reserves do not represent the useful life of the assets, are depreciated over twenty years. Depletion and depreciation for the three months and year ended December 31, 2016 was both $13.07/boe compared to $52.91/boe and $17.67/boe, respectively, for the comparative periods in 2015. The decreases in 2016 were the result of successful drilling results adding proved plus probable reserves to the Company's reserve base at Mica and Doe. The depletion rate in Q4 2015 was unusually high due to adjustments to the Company's reserve base on certain non-core properties which reflected the sharp decline and outlook for commodity prices, as well as the lack of future development capital allocated to the non-core properties. As a result, the Company recorded accelerated depletion of $3.8 million at December 31, 2015. These properties have no assigned proved plus probable reserves, minimal production, and considered unlikely to be developed by the Company in the future.

IMPAIRMENT OF ASSETS

At December 31, 2016, the Company evaluated its property, plant, and equipment CGUs for indicators of impairment or impairment reversals and no indicators were identified, therefore, an impairment test was not performed.

During the year ended December 31, 2015, there were indicators of impairment identified in the Company's CGUs as a result of significant and sustained declines in the forward commodity prices for oil and natural gas. An impairment test was performed on property, plant and equipment assets based on value in use and were primarily based on the net present value of cash flows from oil and natural gas reserves at a pre-tax discount rate of 10 percent. For the year ended December 31, 2015, the Company recorded property, plant, and equipment impairments of $4.6 million relating to its non-Montney CGU mainly as a result of weakening oil and natural gas commodity prices and limited planned capital expenditures in this CGU to maintain their reserve values.

At December 31, 2016, the Company performed an impairment assessment on its exploration and evaluation assets ("E&E") and determined there were no indicators of impairment. Accordingly, an impairment test was not performed.

During the year ended December 31, 2015, the Company incurred $0.9 million of impairment related to non-core lands which were soon to be expiring and of which the Company had no future plans to develop those lands. In addition, during the year ended December 31, 2015 there were indicators of impairment in the Company's non-Montney CGU that the carrying amount of E&E is not likely to be recovered and an impairment test was performed on those E&E assets. E&E assets were evaluated at the CGU level by comparing carrying amounts to the fair value less costs of disposal based on recent land sales prices in the areas in which the Company owns undeveloped land. The impairment tests resulted in an impairment charge totaling $3.7 million in the non-Montney CGU.

GENERAL AND ADMINISTRATIVE	Three Months Ended December 31			Year Ended December 31		
($000s)	**2016**	2015	% Change	**2016**	2015	% Change
G&A expenses (gross)	**1,119**	1,129	(1)	**4,725**	5,354	(12)
G&A capitalized	**(259)**	(358)	(28)	**(413)**	(640)	(35)
G&A recoveries	**(20)**	(28)	(29)	**(106)**	(107)	(1)
G&A expenses (net)	**840**	743	13	**4,206**	4,607	(9)
G&A expenses ($/boe)	**11.08**	7.50	48	**11.11**	9.46	17

General and administrative expenses ("G&A") were consistent in 2016 from 2015 at $0.8 million and $4.2 million for the three months and year ended December 31, 2016, respectively, compared to $0.7 million and $4.6 million for the comparative periods in 2015. Even though overall G&A costs remained consistent, per boe G&A was higher in 2016 due to natural declines in production resulting in spreading gross G&A costs over a lower production volume.

SHARE BASED COMPENSATION	Three Months Ended December 31			Year Ended December 31		
	2016	2015	% Change	**2016**	2015	% Change
Share based compensation ($000s)	**539**	1,072	(50)	**3,546**	5,369	(34)
Share based compensation ($/boe)	**7.11**	10.82	(34)	**9.36**	11.02	(15)

The Company accounts for its share based compensation plans using the fair value method. Under this method, compensation cost is charged to earnings over the vesting period for stock options and warrants granted to officers, directors, employees, and consultants with a corresponding increase to contributed surplus. The fair value of the performance warrants was determined based on a Monte Carlo simulation and the fair value of stock options and purchase warrants was measured based on the Black-Scholes-Merton option-pricing model.

Share based compensation expense decreased to $0.5 million ($7.11/boe) for the fourth quarter of 2016 from $1.1 million ($10.82/boe) for the comparative quarter in 2015. Share based compensation expense decreased to $3.5 million ($9.36/boe) for the year ended December 31, 2016 from $5.4 million ($11.02/boe) in 2015. The decrease is mainly due to using the graded (accelerated) amortization method whereby more expense is recognized earlier in the stock options and warrants expected life. In the year ended December 31, 2016 only 25 thousand stock options were granted.

FINANCE EXPENSES	Three Months Ended December 31			Year Ended December 31		
($000s)	**2016**	2015	% Change	**2016**	2015	% Change
Interest expense	**32**	14	129	**60**	102	(41)
Accretion of decommissioning obligations	**29**	32	(9)	**126**	139	(9)
Finance expenses	**61**	46	33	**186**	241	(23)
Finance expenses ($/boe)	**0.81**	0.46	76	**0.49**	0.49	-

Interest expense increased in Q4 2016 compared to Q4 2015 due to increased letters of guarantees issued during 2016 related to firm transportation commitments. Year-to-date interest costs have decreased in 2016 compared to 2015 due to lower credit facility fees.

Accretion expense has remained consistent for the three months and year ended December 31, 2016 compared to the same periods in 2015.

FINANCE INCOME

Finance income relates to interest earned on cash in the bank. For the three months and year ended December 31, 2016, finance income totaled $0.1 million and $0.5 million, respectively, down from $0.2 million and $0.7 million for the comparative periods in 2015 due to decreased cash balances in the bank resulting mainly from capital expenditures through 2015 and 2016.

DEFERRED INCOME TAXES

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

Estimated tax pools at December 31, 2016 total approximately $221.9 million (December 31, 2015 - $202.3 million).

FUNDS (USED IN) FROM OPERATIONS

Funds used in operations for the fourth quarter of 2016 was $0.1 million ($nil per basic and diluted share) compared to funds from operations of $0.5 million ($nil per basic and diluted share) for the comparative quarter in 2015. For the year ended December 31, 2016 funds used in operations was $1.0 million ($0.01 per basic and diluted share) compared to funds from operations of $0.6 million ($nil per basic and diluted share) in 2015. The decrease was mainly due the decline in production and higher costs associated with new oil wells in Mica and Stoddart partially offset by better oil, NGLs, and natural gas commodity prices.

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

	Three Months Ended December 31			Year Ended December 31		
($000s)	**2016**	2015	% Change	**2016**	2015	% Change
Cash flow used in operating activities	**(945)**	(1,422)	(34)	**(328)**	(216)	52
Add back (deduct):						
Decommissioning expenditures	**-**	33	(100)	**-**	90	(100)
Change in non-cash working capital	**847**	1,853	(54)	**(668)**	741	(190)
Funds (used in) from operations (non-GAAP)	**(98)**	464	(121)	**(996)**	615	(262)

NET (LOSS) EARNINGS

For the three months ended December 31, 2016 the Company incurred a net loss of $1.7 million compared to $15.2 million for the comparative period in 2015. The significant net loss in Q4 2015 was the result of an impairment on the Company's non-Montney assets.

For the year ended December 31, 2016 the Company had a net loss of $12.2 million compared to net earnings of $11.4 million for the comparative period in 2015. The significant net earnings in the year ended December 31, 2015 compared to the net loss in 2016 was the result from the sale of the oil and natural gas properties and equipment in Q2 2015 as the Company recorded a gain on sale of $45.7 million thus significantly increasing net earnings in 2015.

CAPITAL EXPENDITURES	Three Months Ended December 31			Year Ended December 31		
($000s)	**2016**	2015	% Change	**2016**	2015	% Change
Property acquisitions	**500**	9,141	(95)	**4,034**	9,141	(56)
Land	**188**	5,818	(97)	**847**	6,241	(86)
Drilling, completions, and workovers	**6,619**	10,810	(39)	**7,658**	19,460	(61)
Equipment	**4,318**	3,617	19	**9,643**	23,682	(59)
Geological and geophysical	**93**	129	(28)	**392**	636	(38)
Office equipment	**-**	29	(100)	**-**	77	(100)
Total expenditures	**11,718**	29,544	(60)	**22,574**	59,237	(62)
Sale of gas plant equipment	**-**	-	-	**4,000**	-	100
Property dispositions	**-**	-	-	**-**	79,342	(100)

Capital expenditures have declined significantly for the year ended December 31, 2016 from 2015 due to the low oil and natural gas commodity price environment and the Company's preference at this time to preserve its positive cash balance in order to react to opportunities as they arise and dictate the pace of development. During 2016 the Company added Montney acreage adjacent to its Montney land base through both Crown land sales and private land acquisitions as well as began the pipeline system and infrastructure required to tie-in previously drilled wells to the Company's Doe gas plant. This pipeline and infrastructure spending continued into Q1 2017 and four previously drilled wells were subsequently tied-in and began producing. In the fourth quarter of 2016 the Company drilled three net wells in the Montney resulting in two successful horizontal light oil wells at Mica (one completed in Q4 2016 and the other in Q1 2017) and one vertical test well.

During the year ended December 31, 2015 the Company spent the majority of its expenditures on its Montney play at Doe and gas plant equipment. The Company drilled four net wells in the Montney at Doe and Mica which resulted in two successful liquids-rich horizontal natural gas wells, one successful horizontal light oil well and one vertical test well. The Company also continued to add Montney acreage adjacent to its Montney land base through both Crown land sales and private land acquisitions. Throughout the year, the Company also spent money on infrastructure and facilities at Stoddart for the Baldonnel light oil play. During the second quarter of 2015 the Company sold a portion of its oil and natural gas properties and equipment located in Northeast BC for a cash consideration of $79.3 million. The sold assets were producing approximately 1,300 boe/d.

LIQUIDITY AND CAPITAL RESOURCES

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

($000s)	**December 31, 2016**	December 31, 2015	% Change
Current assets	**35,714**	58,740	(39)
Less:			
Current liabilities	**(9,651)**	(13,107)	(26)
Working capital	**26,063**	45,633	(43)

At December 31, 2016, the Company had working capital of $26.1 million and $nil had been drawn on the revolving credit facility.

The Company has a $5.0 million revolving operating demand loan credit facility with a Canadian chartered bank. The revolving credit facility bears interest at prime plus a range of 0.50% to 2.50% and is secured by a $100 million fixed and floating charge debenture on the assets of the Company. At December 31, 2016, $nil had been drawn on the revolving credit facility. At December 31, 2016, the Company had outstanding letters of guarantee of $2.0 million which reduce the amount that can be borrowed under the credit facility. The next review of the revolving credit facility by the bank is scheduled on or before May 1, 2017.

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 $8.4 million of securities of Leucrotta common shares and a margin payable of $1.2 million. The cross-guarantee is intended to be temporary in nature and will be removed as soon as practicable. Significant trading restrictions (blackouts) are placed on all insiders of the Company due to the fact that Leucrotta is a small entity in a large emerging play whereby most operations are material. The cross-guarantee has allowed the President to comply with corporate governance mandates. The $1.0 million has been segregated on the statement of financial position as restricted cash at December 31, 2016.

The ongoing global economic conditions have continued to impact the liquidity in financial and capital markets, restrict access to financing, and cause significant volatility in commodity prices. Despite the economic downturn and financial market volatility, the Company was able to create financial flexibility with the sale of oil and gas properties and equipment for $79.3 million in Q2 2015, sale of gas plant equipment for $4.0 million in Q3 2016, and has a working capital balance of $26.1 million.

Subsequent to December 31, 2016, the Company entered into a purchase and sale agreement to acquire certain lands located within the Company's core Doe/Mica area for an aggregate cash purchase price of approximately $36.0 million. The acquisition is expected to close on or about May 31, 2017.

Subsequent to December 31, 2016, the Company also entered into an agreement with a syndicate of underwriters with respect to an offering of common shares and flow-through common shares by way of a short form prospectus for gross proceeds of $80.0 million (the "Offering"). The Offering is for an aggregate of 33,333,400 common shares at a price of $2.25 per common share and 1,852,000 common shares on a flow-through basis at a price of $2.70 per flow-through common share, closing on about April 26, 2017. The proceeds of the Offering will be used to fund the aforementioned acquisition and the Company's 2017 capital program. The Company has until December 31, 2018 to incur the required Canadian exploration expenditures of $5.0 million.

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

CONTRACTUAL OBLIGATIONS

The following is a summary of the Company's contractual obligations and commitments at December 31, 2016:

($000s)	Total	Less than One Year	One to Three Years	After Three Years
Accounts payable and accrued liabilities	9,651	9,651	-	-
Decommissioning obligations	6,820	-	-	6,820
Office leases	1,081	585	496	-
Firm transportation agreements	23,814	3,878	13,507	6,429
Total contractual obligations	41,366	14,114	14,003	13,249

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

OFF BALANCE SHEET ARRANGEMENTS

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

OUTSTANDING SHARE DATA

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

(000s)	**December 31, 2016**	April 24, 2017
Voting common shares	**165,227**	165,261
Warrants	**15,150**	15,141
Stock options	**8,920**	8,895
Total	**189,297**	189,297

SUMMARY OF QUARTERLY RESULTS

	Q4 2016	Q3 2016	Q2 2016	Q1 2016	Q4 2015	Q3 2015	Q2 2015	Q1 2015
Average Daily Production								
Oil and NGLs (bbls/d)	**234**	300	319	412	479	157	243	387
Natural gas (mcf/d)	**3,543**	4,138	4,549	5,031	3,585	2,244	7,320	11,428
Combined (boe/d)	**824**	989	1,078	1,251	1,076	531	1,463	2,291
($000s, except per share amounts)								
Oil and natural gas sales	**2,281**	2,309	1,953	2,301	2,819	972	2,777	4,291
Funds (used in) from operations	**(98)**	(124)	(491)	(283)	464	(808)	(207)	1,166
Per share - basic and diluted	**-**	-	-	-	-	(0.01)	-	0.01
Net (loss) earnings	**(1,657)**	(4,994)	(2,758)	(2,773)	(15,205)	(3,086)	31,519	(1,816)
Per share - basic and diluted	**(0.01)**	(0.03)	(0.02)	(0.02)	(0.09)	(0.02)	0.19	(0.01)

In Q2 and Q3 2015, production decreased significantly due to the sale of certain oil and gas properties which were producing approximately 1,300 boe/d at the time of disposition. Production increased again in Q4 2015 and Q1 2016 from the successful drilling activities in Northeast BC and then decreased in Q2 through Q4 2016 due to natural declines. In 2015 and 2016, the production declines caused a large decrease in oil and natural gas sales, funds from operations and net earnings. Q2 2015 net earnings saw a significant boost from a gain on the sale of oil and gas properties and equipment of $45.7 million. The large net loss in Q4 2015 was mainly the result of impairment charges on non-Montney assets and derecognizing the deferred income tax asset. The increased loss in Q3 2016 from Q2 2016 was the result of a loss on the sale of certain gas plant equipment of $2.6 million.

CHANGES IN ACCOUNTING POLICIES AND NEW STANDARDS NOT YET ADOPTED

On January 1, 2016, the Company adopted the amendments made to IFRS 11 – Joint Arrangements, which provided new guidance on the accounting for the acquisition of an interest in a joint operation that constitutes a business. There was no impact to the Company as a result of adopting the amended standard.

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

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

On January 13, 2016, the IASB issued IFRS 16 "Leases". The new standard is effective for annual periods beginning on or after January 1, 2019. Earlier application is permitted for entities that apply IFRS 15 "Revenue from Contracts with Customers" at or before the date of initial adoption of IFRS 16. IFRS 16 will replace IAS 17 "Leases". This standard introduces a single lessee accounting model and requires a lessee to recognize assets and liabilities for all leases with a term of more than 12 months, unless the underlying asset is of low value. A lessee is required to recognize a right-of-use asset representing its right to use the underlying asset and a lease liability representing its obligation to make lease payments. The Company intends to adopt IFRS 16 in its financial statements for the annual period beginning on January 1, 2019. The Company is currently identifying contracts that will be classified as leases and evaluating the impact of this standard on its financial statements.

CRITICAL ACCOUNTING ESTIMATES

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

RISK ASSESSMENT

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

Reserves and reserve replacement

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

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

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

Operational risks

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

Market risk

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

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

Interest rate risk
The Company is exposed to interest rate risk when it borrows funds at floating interest rates. The Company currently does not use interest rate hedges or fixed interest rate contracts to manage the Company's exposure to interest rate fluctuations. The amount drawn on the Company's credit facility at December 31, 2016 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 December 31, 2016, the Company did not have any commodity price contracts outstanding.

Credit risk

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

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

The maximum exposure to credit risk is represented by the carrying amount of cash and cash equivalents, restricted cash, and accounts receivable on the statement of financial position. At December 31, 2016, $1.0 million (68%) of the Company's outstanding accounts receivable were current and $0.1 million (5%) were outstanding for more than 90 days. During the year ended December 31, 2016, the Company did not deem any outstanding accounts receivable to be uncollectable.

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

Liquidity risk

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

The Company has commitments for firm transportation over five years for a total of $23.8 million. The Company has a working capital balance of $26.1 million including $33.0 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 RESULTS AND PRODUCTION RATES

The 8-4-82-14W6 well was production tested for 7 days after the original cleanup and produced at an average rate of 1,060 boe/d (50% gas, 50% Oil and Condensate) over that period, excluding load fluid and energizing fluid. At the end of the test, flowing wellhead pressure and production rates were stable.

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

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

FORWARD-LOOKING INFORMATION

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

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

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

ADDITIONAL INFORMATION

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

INDEPENDENT AUDITORS' REPORT

To the Shareholders of Leucrotta Exploration Inc.

We have audited the accompanying financial statements of Leucrotta Exploration Inc., which comprise the statements of financial position as at December 31, 2016 and December 31, 2015, the statements of operations and comprehensive (loss) earnings, shareholders' equity and cash flows for the years then ended, and notes, comprising a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Financial Statements

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

Auditors' Responsibility

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on our judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, we consider internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

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

Opinion

In our opinion, the financial statements present fairly, in all material respects, the financial position of Leucrotta Exploration Inc. as at December 31, 2016 and December 31, 2015, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

KPMG LLP

Chartered Professional Accountants

April 24, 2017
Calgary, Canada

Leucrotta Exploration Inc.
Statements of Financial Position

($000s)	**Note**	**December 31 2016**	December 31 2015
Assets			
Current assets			
Cash and cash equivalents		**32,997**	53,804
Restricted cash	(4)	**1,000**	2,131
Accounts receivable		**1,518**	2,535
Prepaid expenses and deposits		**199**	270
		35,714	58,740
Property, plant, and equipment	(6)	**117,381**	108,553
Exploration and evaluation assets	(7)	**88,540**	85,745
		205,921	194,298
		241,635	253,038
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		**9,651**	13,107
Decommissioning obligations	(9)	**6,820**	6,673
		16,471	19,780
Shareholders' Equity			
Shareholders' capital	(10)	**213,875**	283,587
Contributed surplus		**12,493**	8,405
Reserve from common-control transaction	(10)	**-**	(69,712)
Retained earnings (deficit)		**(1,204)**	10,978
		225,164	233,258
		241,635	253,038
Commitments	(21)		
Subsequent events	(22)		

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

Approved on behalf of the Board of Directors

Rob Zakresky
Director

Tom Medvedic
Director

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

($000s, except per share amounts)	Note	Years Ended December 31 2016	2015
Revenue			
Oil and natural gas sales		**8,844**	10,859
Royalties		**(634)**	(965)
		8,210	9,894
Expenses			
Production		**4,149**	4,041
Transportation		**1,301**	1,203
Depletion and depreciation	(6)	**4,951**	8,607
Asset impairment	(6,7)	**-**	9,216
General and administrative		**4,206**	4,607
Share based compensation	(11)	**3,546**	5,369
Loss (gain) on sale of assets	(5)	**2,563**	(45,404)
Finance income		**(510)**	(674)
Finance expense	(14)	**186**	241
		20,392	(12,794)
(Loss) earnings before taxes		**(12,182)**	22,688
Taxes			
Deferred income tax expense	(15)	**-**	(11,276)
Net (loss) earnings and comprehensive (loss) earnings		**(12,182)**	11,412
Net (loss) earnings per share			
Basic and diluted	(12)	**(0.07)**	0.07

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

Leucrotta Exploration Inc.
Statements of Shareholders' Equity

($000s)	Shareholders' Capital	Contributed Surplus	Reserve from common-control transaction	Retained Earnings (Deficit)	Total Equity
Balance, December 31, 2014	283,587	1,955	(69,712)	(434)	215,396
Net earnings	-	-	-	11,412	11,412
Share based compensation	-	6,450	-	-	6,450
Balance, December 31, 2015	283,587	8,405	(69,712)	10,978	233,258
Balance, December 31, 2015	283,587	8,405	(69,712)	10,978	233,258
Net loss	-	-	-	(12,182)	(12,182)
Share based compensation	-	4,088	-	-	4,088
Reclassification	(69,712)	-	69,712	-	-
Balance, December 31, 2016	213,875	12,493	-	(1,204)	225,164

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

Leucrotta Exploration Inc.
Statements of Cash Flows

		Years Ended December 31	
($000s)	Note	2016	2015
Operating Activities			
Net (loss) earnings		**(12,182)**	11,412
Depletion and depreciation	(6)	**4,951**	8,607
Asset impairment	(6,7)	**-**	9,216
Share based compensation	(11)	**3,546**	5,369
Finance expense	(14)	**186**	241
Interest paid	(14)	**(60)**	(102)
Loss (gain) on sale of assets	(5)	**2,563**	(45,404)
Deferred income tax expense	(15)	**-**	11,276
Decommissioning expenditures	(9)	**-**	(90)
Change in non-cash working capital	(20)	**668**	(741)
		(328)	(216)
Investing Activities			
Capital expenditures - property, plant, and equipment	(6)	**(10,190)**	(23,490)
Capital expenditures - exploration and evaluation assets	(7)	**(8,350)**	(26,606)
Property acquisitions	(5,7)	**(4,034)**	(9,141)
Disposition of oil and natural gas properties and equipment	(5)	**4,000**	79,342
Change in non-cash working capital	(20)	**(1,905)**	(7,414)
		(20,479)	12,691
Change in cash and cash equivalents		**(20,807)**	12,475
Cash and cash equivalents, beginning of year		**53,804**	41,329
Cash and cash equivalents, end of year		**32,997**	53,804

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

1. REPORTING ENTITY

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

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

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

2. BASIS OF PRESENTATION

(a) Statement of compliance

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

The financial statements were authorized for issuance by the Board of Directors on April 24, 2017.

(b) Basis of measurement

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

(c) Functional and presentation currency

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

(d) Use of estimates and judgments

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

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

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

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

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

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

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

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

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

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

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

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

3. SIGNIFICANT ACCOUNTING POLICIES

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

(a) Joint arrangements

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

(b) Financial instruments

Non-derivative financial instruments

The Company's financial instruments comprise cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities, and credit facility, all of which are measured at amortized cost. Financial instruments at amortized cost are recognized initially at fair value net of any directly attributable transaction costs. Subsequent to initial recognition, financial instruments at amortized cost are measured using the effective interest method, less any impairment losses.

Cash and cash equivalents and restricted cash
Cash and cash equivalents and restricted cash comprise cash on hand, term deposits held with banks, and other short-term highly liquid investments with original maturities of three months or less, measured at amortized cost. Any transaction costs are recognized in profit or loss as incurred.

Financial assets and liabilities are offset and the net amount presented on the statement of financial position if, and only if, the Company has a legal right to offset the amounts and intends to either settle on a net basis or to realize the asset and settle the liability simultaneously.

Derivative financial instruments

From time to time, the Company may enter into certain financial derivative contracts in order to manage the exposure to market risks from fluctuations in commodity prices. These instruments are not used for trading or speculative purposes. The

Company does not designate financial derivative contracts as effective accounting hedges, and thus does not apply hedge accounting, even though the Company considers all commodity contracts to be economic hedges. As a result, all financial derivative contracts are classified as fair value through profit or loss and are measured at fair value, with changes therein recognized in profit or loss. Transaction costs are recognized in profit or loss when incurred.

Share capital

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

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

Recognition and measurement

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

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

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

Development and production costs
Items of property, plant, and equipment, which include oil and natural gas development and production assets, are measured at cost less accumulated depletion and depreciation and accumulated impairment losses. The cost of development and production assets includes: transfers from exploration and evaluation assets, which generally include the cost to drill the well and the cost of the associated land upon determination of technical feasibility and commercial viability; the cost to complete and tie-in the well; facility costs; the cost of recognizing provisions for future restoration and decommissioning obligations; geological and geophysical costs; and directly attributable overhead.

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

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

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

Subsequent costs

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

Non-monetary asset swaps

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

Depletion and depreciation

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

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

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

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

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

Leased assets

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

(d) Impairment

Financial assets

A financial asset is assessed at each reporting date to determine whether there is any objective evidence that it is impaired. A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset. An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate.

All impairment losses are recognized in profit or loss. An impairment loss is reversed if the reversal can be related objectively to an event occurring after the impairment loss was recognized. For financial assets measured at amortized cost, the reversal is recognized in profit or loss.

Non-financial assets

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

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

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

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

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

(e) Business combinations

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

(f) Share based compensation

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

(g) Provisions

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

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

(h) Revenue

Revenue from the sale of oil and natural gas is recorded when the significant risks and rewards of ownership of the product are transferred to the buyer which is usually when legal title passes to the external party.

(i) Finance income and expense

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

(j) Income tax

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

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

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

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

(k) Per share amounts

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

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

On January 1, 2016, the Company adopted the amendments made to IFRS 11 – Joint Arrangements, which provided new guidance on the accounting for the acquisition of an interest in a joint operation that constitutes a business. There was no impact to the Company as a result of adopting the amended standard.

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

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

On January 13, 2016, the IASB issued IFRS 16 "Leases". The new standard is effective for annual periods beginning on or after January 1, 2019. Earlier application is permitted for entities that apply IFRS 15 "Revenue from Contracts with Customers" at or before the date of initial adoption of IFRS 16. IFRS 16 will replace IAS 17 "Leases". This standard introduces a single lessee accounting model and requires a lessee to recognize assets and liabilities for all leases with a term of more than 12 months, unless the underlying asset is of low value. A lessee is required to recognize a right-of-use asset representing its right to use the underlying asset and a lease liability representing its obligation to make lease payments. The Company intends to adopt IFRS 16 in its financial statements for the annual period beginning on January 1, 2019. The Company is currently identifying contracts that will be classified as leases and evaluating the impact of this standard on its financial statements.

4. RESTRICTED CASH

	December 31, 2016	December 31, 2015
Cross-guarantee on margin account	**1,000**	1,000
Letters of guarantees	**-**	1,131
	1,000	2,131

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 $8.4 million of securities of Leucrotta common shares and a margin payable of $1.2 million. The cross-guarantee is intended to be temporary in nature and will be removed as soon as practicable. Significant trading restrictions (blackouts) are placed on all insiders of the Company due to the fact that Leucrotta is a small entity in a large emerging play whereby most operations are material. The cross-guarantee has allowed the President to comply with corporate governance mandates.

During the year ended December 31, 2016, the Company revised its credit facility (see note 8) and no longer has a set-off agreement on its borrowing base and therefore outstanding letters of guarantee have been removed from restricted cash.

5. PROPERTY ACQUISITIONS AND DISPOSITIONS

a) Property acquisitions

During the year ended December 31, 2016, the Company closed three property acquisitions for total cash consideration of $4.0 million (2015 – one property acquisition for $9.1 million). Net assets acquired were undeveloped land in the Company's core area of Northeast BC adding to the Company's undeveloped land inventory in the area with a focus on the Montney formation.

b) Equipment disposition

During the year ended December 31, 2016, the Company sold certain gas plant equipment for cash proceeds of $4.0 million.

c) Property disposition

During the year ended December 31, 2015, the Company sold a portion of its assets located in the Greater Dawson area in Northeast BC for a cash consideration of approximately $79.3 million. The sold assets were producing approximately 1,300 boe/d.

Book value of net assets disposed	
Property, plant, and equipment	31,565
Exploration and evaluation assets	3,097
Decommissioning obligations	(1,056)
	33,606
Consideration	
Cash	79,342
Gain on sale of assets	45,736

d) Property swap

During the year ended December 31, 2015, the Company completed a property swap in which it disposed of non-core producing assets located at Flatrock, BC in exchange for undeveloped land located in its core Dawson area in Northeast BC. The sold assets were producing approximately 75 boe/d.

Book value of net assets disposed	
Property, plant, and equipment	1,969
Decommissioning obligations	(617)
	1,352
Consideration	
Exploration and evaluation assets	1,020
Loss on swap of assets	(332)

6. PROPERTY, PLANT, AND EQUIPMENT

Cost	**Total**
Balance, December 31, 2014	105,393
Additions	23,490
Dispositions	(41,411)
Transfer from exploration and evaluation assets	40,726
Change in decommissioning obligations	1,011
Capitalized share based compensation	202
Balance, December 31, 2015	129,411
Additions	**10,190**
Dispositions	**(6,563)**
Transfer from exploration and evaluation assets	**10,086**
Change in decommissioning obligations	**21**
Capitalized share based compensation	**45**
Balance, December 31, 2016	**143,190**

Accumulated Depletion, Depreciation, and Impairment	Total
Balance, December 31, 2014	15,540
Depletion and depreciation	8,607
Impairment	4,588
Dispositions	(7,877)
Balance, December 31, 2015	20,858
Depletion and depreciation	**4,951**
Balance, December 31, 2016	**25,809**

Net Book Value	Total
December 31, 2015	108,553
December 31, 2016	**117,381**

During the year ended December 31, 2016, approximately $0.1 million (2015 - $0.2 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 year ended December 31, 2016 included an estimated $95.7 million (2015 - $69.0 million) for future development costs associated with proved plus probable undeveloped reserves and excluded approximately $2.8 million (2015 - $1.4 million) for the estimated salvage value of production equipment and facilities and approximately $nil (2015 - $28.2 million) of newly constructed equipment not in use.

At December 31, 2015, the Company had adjustments to its reserve base on certain non-core properties which reflected the sharp decline and outlook for commodity prices, as well as the lack of future development capital allocated to the non-core properties. As a result, the Company recorded accelerated depletion of $3.8 million at December 31, 2015. These properties have no assigned proved plus probable reserves, minimal production, and considered unlikely to be developed by the Company in the future.

Impairment

At December 31, 2016, the Company evaluated its property, plant, and equipment CGUs for indicators of impairment or impairment reversals and no indicators were identified, therefore, an impairment test was not performed.

During the year ended December 31, 2015, there were indicators of impairment identified in the Company's CGUs as a result of significant and sustained declines in the forward commodity prices for oil and natural gas. An impairment test was performed on property, plant, and equipment assets based on value in use using the following commodity price estimates of the Company's independent reserve evaluators:

Year	West Texas Intermediate Oil ($US/bbl)	Foreign Exchange Rate (USD/CDN)	Edmonton Light, Sweet Oil ($CDN/bbl)	AECO Gas Price ($CDN/mmbtu)
2016	44.00	0.725	55.86	2.76
2017	52.00	0.750	64.00	3.27
2018	58.00	0.775	68.39	3.45
2019	64.00	0.800	73.75	3.63
2020	70.00	0.825	78.79	3.81
2021	75.00	0.850	82.35	3.90
2022	80.00	0.850	88.24	4.10
2023	85.00	0.850	94.12	4.30
2024	87.88	0.850	96.48	4.50
2025	89.63	0.850	98.41	4.60
Escalate Thereafter	2.0% per year		2.0% per year	2.0% per year

The impairment tests at December 31, 2015 were primarily based on the net present value of cash flows from oil and natural gas reserves at a pre-tax discount rate of 10 percent. For the year ended December 31, 2015, the Company recorded property, plant, and equipment impairments of $4.6 million relating to its non-Montney CGU mainly as a result of weakening oil and natural gas commodity prices, and limited planned capital expenditures in this CGU to maintain their reserve values and the recent decision to explore sale or swap opportunities on its non-Montney assets in an effort to focus on and maximize value from its core Montney assets. At December 31, 2015 the recoverable amount of the non-Montney CGU, net of decommissioning obligations, is estimated to be $9.3 million.

7. EXPLORATION AND EVALUATION ASSETS

	Total
Balance, December 31, 2014	96,550
Property acquisitions	9,141
Additions	27,626
Dispositions	(3,097)
Transfer to property, plant, and equipment	(40,726)
Impairment	(4,628)
Capitalized share based compensation	879
Balance, December 31, 2015	85,745
Property acquisitions	**4,034**
Additions	**8,350**
Transfer to property, plant, and equipment	**(10,086)**
Capitalized share based compensation	**497**
Balance, December 31, 2016	**88,540**

Exploration and evaluation assets ("E&E") consist of the Company's exploration projects which are pending the determination of proved or probable reserves. Additions represent the Company's share of costs incurred on exploration and evaluation assets during the period, consisting primarily of undeveloped land and drilling costs until the drilling of the well is complete and the results have been evaluated. All expenditures for the years ended December 31, 2016 and 2015 related to Northeast BC. Included in additions for the year ended December 31, 2015 was $1.0 million of non-cash additions from a property swap (see note 5).

During the year ended December 31, 2016, approximately $0.3 million (2015 - $0.4 million), respectively, of directly attributable general and administrative costs were capitalized as expenditures on exploration and evaluation assets.

At December 31, 2016, the Company performed an impairment assessment on its exploration and evaluation assets ("E&E") and determined there were no indicators of impairment. Accordingly, an impairment test was not performed.

During the year ended December 31, 2016, the Company incurred $nil (2015 - $0.9 million) of impairment related to non-core lands which were soon to be expiring and of which the Company had no future plans to develop those lands. As at December 31, 2015 there were indicators of impairment in the Company's non-Montney CGU that the carrying amount of E&E assets was not likely to be recovered and an impairment test was performed on those E&E assets. E&E assets were evaluated at the CGU level by comparing carrying amounts to the fair value less costs of disposal based on recent land sales prices in the areas in which the Company owns undeveloped land. The impairment tests resulted in an impairment charge totaling $3.7 million in the non-core non-Montney CGU.

8. CREDIT FACILITY

The Company has a $5.0 million revolving operating demand loan credit facility with a Canadian chartered bank. The revolving credit facility bears interest at prime plus a range of 0.50% to 2.50% and is secured by a $100 million fixed and floating charge debenture on the assets of the Company. At December 31, 2016, $nil had been drawn on the revolving credit facility. At December 31, 2016, the Company had outstanding letters of guarantee of $2.0 million which reduce the amount that can be borrowed under the credit facility. The next review of the revolving credit facility by the bank is scheduled on or before May 1, 2017.

The Company's credit facility includes a covenant requiring the Company to maintain an adjusted working capital ratio of not less than one-to-one. The working capital ratio, as defined by its creditor, is calculated as current assets plus any undrawn amounts available on its credit facility less current liabilities excluding any current portion drawn on the credit facility. The Company was compliant with this covenant at December 31, 2016.

9. DECOMMISSIONING OBLIGATIONS

The Company's decommissioning obligations result from its ownership interest in oil and natural gas assets including well sites and gathering systems. The total decommissioning obligation is estimated based on the Company's net ownership interest in all wells and facilities, estimated costs to abandon and reclaim the wells and facilities, and the estimated timing of the costs to be incurred in future periods. The total undiscounted amount of the estimated cash flows (adjusted for inflation at 2% per year) required to settle the decommissioning obligations is approximately $12.1 million (December 31, 2015 - $11.4 million) which is estimated to be incurred over the next 34 years. At December 31, 2016, a risk-free rate of 2.2% (December 31, 2015 – 2.0%) was used to calculate the net present value of the decommissioning obligations.

	Year Ended December 31, 2016	Year Ended December 31, 2015
Balance, beginning of year	**6,673**	7,286
Provisions incurred	**339**	466
Provisions settled	**-**	(90)
Dispositions	**-**	(1,673)
Revisions in estimated cash flows	**-**	90
Revisions due to change of discount rates	**(318)**	455
Accretion	**126**	139
Balance, end of year	**6,820**	6,673

10. SHAREHOLDERS' CAPITAL

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

Voting Common Shares	**Number**	**Amount**
Balance, December 31, 2014 and 2015	165,227	283,587
Reclassification of Reserve from common-control transaction	-	(69,712)
Balance, December 31, 2016	**165,227**	**213,875**

In connection with the arrangement on June 12, 2014 involving Crocotta Energy Inc. ("Crocotta") and Long Run Exploration Ltd., the reserve created from the common-control transaction represents the difference between the fair value of the Leucrotta shares issued to existing Crocotta shareholders and the net book value of the acquired assets and assumed liabilities, and has been reclassified to Shareholders' Capital as at December 31, 2016.

11. SHARE BASED COMPENSATION PLANS

Stock options

The Company has authorized and reserved for issuance 16.5 million common shares under a stock option plan enabling certain officers, directors, employees, and consultants to purchase common shares. The Company will not issue options exceeding 10% of the shares outstanding at the time of the option grants (the performance warrants described below are aggregated with any options for the 10% limit). Under the plan, the exercise price of each option equals the market price of the Company's shares on the date of the grant and an option's maximum term is ten years. At December 31, 2016, 8.9 million options were outstanding at an average exercise price of $1.09 per share.

	Number of Options	**Weighted Average Exercise Price ($)**
Balance, December 31, 2014	4,672	1.29
Granted	4,248	0.87
Forfeited	(25)	0.93
Balance, December 31, 2015	8,895	1.09
Granted	**25**	**1.40**
Balance, December 31, 2016	**8,920**	**1.09**
Exercisable, December 31, 2016	4,522	1.16

The following table summarizes the stock options outstanding and exercisable at December 31, 2016:

	Options Outstanding			**Options Exercisable**	
Exercise Price	**Number**	**Weighted Average Remaining Life**	**Weighted Average Exercise Price**	**Number**	**Weighted Average Exercise Price**
$0.80 to $1.00	4,230	2.9	0.87	1,407	0.87
$1.01 to $1.29	4,690	2.0	1.29	3,115	1.29
	8,920	2.4	1.09	4,522	1.16

During the year ended December 31, 2016, the Company recognized $1.6 million (2015 - $1.6 million) of share based compensation related to the stock options. At December 31, 2016 there was $0.9 million remaining as unrecognized share based compensation related to the stock options.

Performance Warrants

The Company has 7.5 million performance warrants outstanding to certain officers, directors, employees, and consultants to purchase common shares at an exercise price of $1.70. The performance warrants expire on August 18, 2019 and are subject to both time vesting equally over three years and performance vesting as follows:

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

	Number	Exercise Price
Balance, December 31, 2014, 2015 and 2016	**7,500**	**1.70**
Exercisable, December 31, 2016	4,500	1.70

During the year ended December 31, 2016, the Company recognized $1.4 million (2015 - $2.5 million) of share based compensation related to the performance warrants. At December 31, 2016 there was $0.5 million remaining as unrecognized share based compensation related to the performance warrants. No new performance warrants were granted during the year ended December 31, 2016. The remaining life of the performance warrants at December 31, 2016 is 2.6 years (December 31, 2015 – 3.6 years).

Purchase Warrants

The Company has 7.65 million purchase warrants outstanding to certain officers, directors, employees, and consultants to purchase common shares at an exercise price of $2.04 expiring on September 12, 2019 vesting equally over three years.

	Number of Warrants	Exercise Price
Balance, December 31, 2014, 2015 and 2016	**7,650**	**2.04**
Exercisable, December 31, 2016	5,100	2.04

During the year ended December 31, 2016, the Company recognized $1.1 million (2015 - $2.4 million) of share based compensation related to the purchase warrants. At December 31, 2016 there was $0.4 million remaining as unrecognized share based compensation related to the purchase warrants. No new purchase warrants were granted during the year ended December 31, 2016. The remaining life of the purchase warrants at December 31, 2016 is 2.7 years (December 31, 2015 – 3.7 years).

Share based compensation

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

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

There were no performance warrants or purchase warrants granted during the years ended December 31, 2016 and 2015.

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

	December 31, 2016	December 31, 2015
Risk-free interest rate (%)	**0.5**	0.6
Expected life (years)	**3.5**	3.5
Expected volatility (%)	**63.3**	62.3
Expected dividend yield (%)	**-**	-
Forfeiture rate (%)	**5.0**	5.0
Weighted average fair value of options granted ($ per option)	**0.63**	0.39

12. PER SHARE AMOUNTS

There were 8.9 million stock options, 7.7 million purchase warrants and 7.5 million performance warrants that were excluded from the weighted-average share calculations for the years ended December 31, 2015 and 2016 because they were anti-dilutive.

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

	December 31, 2016	December 31, 2015
Weighted average number of shares - basic	**165,227**	165,227
Dilutive effect of share based compensation plans	**-**	-
Weighted average number of shares - diluted	**165,227**	165,227

13. KEY MANAGEMENT PERSONNEL

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

	December 31, 2016	December 31, 2015
Short-term wages and benefits	**1,690**	1,785
Share based compensation (1)	**3,189**	5,125
Total (2,3)	**4,879**	6,910

(1) Represents the amortization of share based compensation expense associated with the Company's share based compensation plans granted to key management personnel inclusive of any capitalized portion.
(2) Balances outstanding and payable at December 31, 2016 were $nil (2015 - $nil).
(3) At December 31, 2016, key management personnel included 12 individuals (2015 – 12 individuals).

14. FINANCE EXPENSE

Finance expense includes the following:

	December 31, 2016	December 31, 2015
Interest expense	**60**	102
Accretion of decommissioning obligations	**126**	139
Finance expense	**186**	241

15. INCOME TAXES

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

	December 31, 2016	December 31, 2015
(Loss) earnings before taxes	**(12,182)**	22,688
Statutory income tax rate	**26.5%**	26.0%
Expected income tax (recovery) expense	**(3,228)**	5,899
Increase (decrease) in income taxes resulting from:		
Share based compensation and other non-deductible amounts	**953**	1,443
Changes in statutory income tax rate	**-**	(301)
Change in unrecognized deferred income tax asset	**2,275**	4,235
Income tax expense	**-**	11,276

The tax rate consists of the combined federal and provincial statutory tax rates for the Company for the years ended December 31, 2016 and December 31, 2015. The tax rate increase in 2016 reflects the impact of an entire year of the Alberta corporate tax rate increase from 10% to 12% effective July 1, 2015.

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

(b) Recognized deferred tax balances for the years ended December 31, 2016 and 2015 are as follows:

	Balance December 31, 2014	**Recognized in Earnings or Loss**	**Recognized in Equity**	**Balance December 31, 2015 and 2016**
Deferred income tax assets:				
Oil and natural gas properties and equipment	8,795	(8,795)	-	-
Decommissioning obligations	1,858	(1,858)	-	-
Share issue costs	623	(623)	-	-
Net deferred income tax asset	11,276	(11,276)	-	-

At December 31, 2016, the Company has estimated federal tax pools of $221.9 million (December 31, 2015 - $202.3 million) available for deduction against future taxable income.

(c) Unrecognized deductible temporary differences are as follows:

	December 31, 2016	December 31, 2015
Oil and natural gas properties and equipment	**11,913**	5,692
Decommissioning obligations	**6,820**	6,673
Share issue costs	**1,381**	1,912
Non-capital losses	**4,454**	1,705
Unrecognized deductible temporary differences	**24,568**	15,982

Non-capital losses of $4.5 million will expire between 2035 and 2036.

16. FAIR VALUE OF FINANCIAL INSTRUMENTS

Cash and cash equivalents, restricted cash, accounts receivable, accounts payable and accrued liabilities

The fair value of cash and cash equivalents, restricted cash, accounts receivable, and accounts payable and accrued liabilities at December 31, 2016 and December 31, 2015 approximated their carrying value due to their short term to maturity.

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

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

During the years ended December 31, 2016 and 2015, there were no transfers between level 1, level 2, and level 3 classified assets and liabilities.

17. FINANCIAL RISK MANAGEMENT

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

Market risk

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

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

Interest rate risk
The Company is exposed to interest rate risk when it borrows funds at floating interest rates. The Company currently does not use interest rate hedges or fixed interest rate contracts to manage the Company's exposure to interest rate fluctuations. The amount drawn on the Company's credit facility at December 31, 2016 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. A $1.00/boe increase or decrease in commodity prices would have impacted net earnings by approximately $0.4 million for the year ended December 31, 2016 (2015 - $0.5 million).

The Company did not enter into commodity price contracts to manage future cash flows as at December 31, 2016.

Credit risk

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

Company generally grants unsecured credit but routinely assesses the financial strength of its customers and joint interest partners.

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

The maximum exposure to credit risk is represented by the carrying amount of cash and cash equivalents, restricted cash, and accounts receivable on the statement of financial position. At December 31, 2016, $1.0 million (68%) of the Company's outstanding accounts receivable were current and $0.1 million (5%) were outstanding for more than 90 days. During the year ended December 31, 2016, the Company did not deem any outstanding accounts receivable to be uncollectable.

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

Liquidity risk

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

See note 21 for a summary of contractual commitments at December 31, 2016. The Company's accounts payable and accrued liabilities are all due within the current operating period.

18. CAPITAL MANAGEMENT

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

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

	December 31, 2016	December 31, 2015
Shareholders' equity	**225,164**	233,258
Working capital	**26,063**	45,633

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

19. SUPPLEMENTAL DISCLOSURES

Presentation of expenses

The Company's statements of operations and comprehensive (loss) earnings is prepared primarily by nature of expense, with the exception of employee compensation costs which are included in general and administrative expenses. Included in general and administrative expenses for the year ended December 31, 2016 are $3.1 million of wages and benefits (2015 - $3.4 million).

20. SUPPLEMENTAL CASH FLOW INFORMATION

	December 31, 2016	December 31, 2015
Restricted cash	**1,131**	(2,131)
Accounts receivable	**1,017**	856
Prepaid expenses and deposits	**71**	115
Accounts payable and accrued liabilities	**(3,456)**	(6,995)
Change in non-cash working capital	**(1,237)**	(8,155)
Relating to:		
Investing	**(1,905)**	(7,414)
Operating	**668**	(741)
Change in non-cash working capital	**(1,237)**	(8,155)

21. COMMITMENTS

The following is a summary of the Company's commitments at December 31, 2016:

	2017	**2018**	**2019**	**2020**	**2021**	**Thereafter**	**Total**
Office leases	585	496	-	-	-	-	1,081
Firm transportation agreements	3,878	5,613	7,894	6,429	-	-	23,814
	4,463	6,109	7,894	6,429	-	-	24,895

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

22. SUBSEQUENT EVENTS

Subsequent to December 31, 2016 the Company entered into a purchase and sale agreement to acquire certain lands located within the Company's core Doe/Mica area for an aggregate cash purchase price of approximately $36.0 million. The acquisition is expected to close on or about May 31, 2017.

Subsequent to December 31, 2016 the Company also entered into an agreement with a syndicate of underwriters with respect to an offering of common shares and flow-through common shares by way of a short form prospectus for gross proceeds of $80.0 million (the "Offering"). The Offering is for an aggregate of 33,333,400 common shares at a price of $2.25 per common share and 1,852,000 common shares on a flow-through basis at a price of $2.70 per flow-through common share, closing on April 26, 2017. The proceeds of the Offering will be used to fund the aforementioned acquisition and the Company's 2017 capital program. The Company has until December 31, 2018 to incur the required Canadian exploration expenditures of $5.0 million.

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

LEUCROTTA
EXPLORATION INC.

For further information, please visit our website at **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

LEUCROTTA
EXPLORATION INC.

LEUCROTTA EXPLORATION INC.
700, 639 – 5th Avenue SW
Calgary, Alberta T2P 0M9

P 403.705.4525 **E** info@leucrotta.ca