LEUCROTTA EXPLORATION INC.

Q3 2021 RESULTS

FORWARD WITH FORTITUDE

Financial and operating results for the three and nine months ended **SEPTEMBER 30, 2021**

HIGHLIGHTS

- Drilled 4-well pad at Mica, BC expected to be completed in Q4 2021.
- September 30, 2021 adjusted working capital (2) balance of $45.5 million.
- Increased adjusted funds flow (1) by 231% to $1.9 million in Q3 2021 from $0.6 million in Q3 2020.

FINANCIAL RESULTS	**THREE MONTHS ENDED SEPTEMBER 30**			**NINE MONTHS ENDED SEPTEMBER 30**		
($000s, except per share amounts)	**2021**	2020	% Change	**2021**	2020	% Change
OIL AND NATURAL GAS SALES	**6,954**	5,841	19	**23,854**	17,071	40
CASH FLOW FROM OPERATING ACTIVITIES	**967**	368	163	**5,142**	975	427
Per share - basic and diluted	**-**	-	-	**0.02**	-	100
ADJUSTED FUNDS FLOW (1)	**1,939**	586	231	**6,595**	548	1,103
Per share - basic and diluted	**0.01**	-	100	**0.03**	-	100
NET EARNINGS (LOSS)	**66,545**	(2,525)	(2,735)	**66,120**	(94,158)	(170)
Per share - basic and diluted	**0.27**	(0.01)	(2,800)	**0.29**	(0.47)	(162)
CAPITAL EXPENDITURES	**13,981**	647	2,061	**18,215**	13,321	37
PROCEEDS ON SALE OF PROPERTIES AND EQUIPMENT	**-**	-	-	**30,000**	8,206	266
ADJUSTED WORKING CAPITAL (DEFICIENCY) (2)				**45,503**	(4,421)	(1,129)
COMMON SHARES OUTSTANDING (000S)						
Weighted average - basic	**247,641**	200,525	23	**231,694**	200,525	16
Weighted average - diluted	**247,952**	200,525	24	**231,737**	200,525	16
End of period - basic				**247,641**	200,525	23
End of period - fully diluted				**290,111**	218,527	33

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

(2) Adjusted working capital (deficiency) includes current assets less current liabilities excluding the effects of any current portion of risk management contracts. Adjusted working capital (deficiency) 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.

OPERATING RESULTS [1]	Three Months Ended September 30			Nine Months Ended September 30		
	2021	2020	% Change	**2021**	2020	% Change
Daily production [2]						
Oil and condensate (bbls/d)	**299**	542	(45)	**390**	648	(40)
Other NGLs (bbls/d)	**26**	248	(90)	**34**	278	(88)
Oil and NGLs (bbls/d)	**325**	790	(59)	**424**	926	(54)
Natural gas (mcf/d)	**8,953**	13,739	(35)	**10,840**	14,036	(23)
Oil equivalent (boe/d)	**1,817**	3,080	(41)	**2,231**	3,266	(32)
Oil and natural gas sales						
Oil and condensate ($/bbl)	**81.52**	45.19	80	**72.70**	36.87	97
Other NGLs ($/bbl)	**34.91**	22.95	52	**30.68**	20.04	53
Oil and NGLs ($/bbl)	**77.74**	38.21	103	**69.34**	31.81	118
Natural gas ($/mcf)	**5.62**	2.42	132	**5.35**	2.34	129
Oil equivalent ($/boe)	**41.59**	20.62	102	**39.16**	19.08	105
Royalties						
Oil and NGLs ($/bbl)	**11.61**	1.93	502	**9.02**	1.49	505
Natural gas ($/mcf)	**0.50**	0.06	733	**0.41**	0.05	720
Oil equivalent ($/boe)	**4.55**	0.76	499	**3.69**	0.63	486
Net operating expenses [3]						
Oil and NGLs ($/bbl)	**9.17**	10.19	(10)	**9.26**	9.87	(6)
Natural gas ($/mcf)	**0.86**	1.04	(17)	**0.87**	0.99	(12)
Oil equivalent ($/boe)	**5.89**	7.24	(19)	**6.00**	7.05	(15)
Transportation and marketing expenses						
Oil and NGLs ($/bbl)	**0.74**	0.32	131	**0.80**	0.84	(5)
Natural gas ($/mcf)	**1.23**	1.45	(15)	**1.40**	1.56	(10)
Oil equivalent ($/boe)	**6.20**	6.53	(5)	**6.93**	6.95	(-)
Operating netback [3]						
Oil and NGLs ($/bbl)	**56.22**	25.77	118	**50.26**	19.61	156
Natural gas ($/mcf)	**3.03**	(0.13)	(2,431)	**2.67**	(0.26)	(1,127)
Oil equivalent ($/boe)	**24.95**	6.09	310	**22.54**	4.45	407
Depletion and depreciation ($/boe)	**(7.67)**	(10.08)	(24)	**(7.94)**	(8.82)	(10)
Asset (impairment) reversal ($/boe)	**397.21**	-	100	**109.04**	(98.22)	(211)
General and administrative expenses ($/boe)	**(6.78)**	(3.94)	72	**(6.96)**	(3.77)	85
Share based compensation ($/boe)	**(2.26)**	(0.64)	253	**(2.59)**	(0.31)	735
Gain on sale of equipment ($/boe)	**-**	-	-	**-**	1.68	(100)
Finance expense ($/boe)	**(0.63)**	(0.33)	91	**(0.57)**	(0.25)	128
Finance income ($/boe)	**0.38**	-	100	**0.29**	-	100
Realized loss on risk management contracts ($/boe)	**(3.72)**	-	100	**(2.35)**	-	100
Unrealized loss on risk management contracts ($/boe)	**(3.67)**	-	100	**(2.97)**	-	100
Deferred income tax recovery ($/boe)	**0.20**	-	100	**0.06**	-	100
Net earnings (loss) ($/boe)	**398.01**	(8.90)	(4,572)	**108.55**	(105.24)	(203)

(1) "bbls" and "bbls/d" refers to barrels and barrels per day, "mcf" and "mcf/d" refers to thousand cubic feet and thousand cubic feet per day, and "boe" and "boe/d" refers to barrel of oil equivalent and barrel of oil equivalent per day. 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) "Natural gas" refers to shale gas; "Oil and condensate" refers to condensate, light crude oil, and tight oil combined; "Other NGLs" refers to butane, propane and ethane combined; "Oil and NGLs" refers to light and medium crude oil, tight oil, and NGLs combined, "Oil equivalent" refers to the total oil equivalent of shale gas, light and medium crude oil, tight oil, and NGLs combined, using the conversion rate of six thousand cubic feet of shale gas to one barrel of oil equivalent as described above. Readers are referred to the "Product Types" section for a complete breakdown of sales volumes for applicable periods by specific product types of shale gas, light and medium crude oil, tight oil, and NGLs.

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

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

November 15, 2021

The MD&A should be read in conjunction with the unaudited condensed interim financial statements and related notes for the three and nine months ended September 30, 2021 and the audited financial statements and MD&A for the year ended December 31, 2020. The unaudited condensed interim financial statements and financial data contained in the MD&A have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). All dollar amounts are expressed in Canadian currency, unless otherwise noted.

DESCRIPTION OF BUSINESS

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

OIL AND GAS TERMS

The Company uses the following frequently recurring oil and gas industry terms in the MD&A:

Liquids

bbls	Barrels
Bbl/d	Barrels per day
NGLs	Natural gas liquids (includes condensate, pentane, butane, propane, and ethane)
Condensate	Pentane and heavier hydrocarbons

Natural Gas

Mcf	Thousands of cubic feet
Mcf/d	Thousands of cubic feet per day
MMbtu	Million of British thermal units
MMbtu/d	Million of British thermal units per day

Oil Equivalent

Boe	Barrels of oil equivalent
Boe/d	Barrels of oil equivalent per day

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.

NOTE REGARDING PRODUCT TYPES

The Company uses the following references to sales volumes in the MD&A:

Natural gas refers to shale gas
Oil and condensate refers to condensate, light and medium crude oil, and tight oil combined
Other NGLs refers to butane, propane and ethane combined
Oil and NGLs refers to light and medium crude oil, tight oil, and NGLs combined
Oil equivalent refers to the total oil equivalent of shale gas, light and medium crude oil, tight oil, and NGLs combined, using the conversion rate of six thousand cubic feet of shale gas to one barrel of oil equivalent as described above.

Readers are referred to the "Product Types" section for a complete breakdown of sales volumes for applicable periods by specific product types of shale gas, light and medium crude oil, tight oil, and NGLs.

NON-GAAP MEASURES

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

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

Management uses adjusted working capital (deficiency) as a measure to assess the Company's financial position. Adjusted working capital (deficiency) includes current assets less current liabilities excluding the effects of any current portion of risk management contracts. Adjusted working capital (deficiency) is reconciled to working capital (deficiency) under the heading "Liquidity and Capital Resources".

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

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

UPDATE

Operations

In Q3 2021, Leucrotta successfully drilled its 4-well Montney test pad at Mica and commenced completing these wells in early Q4 2021. The Mica pad wells were drilled with approximately 2,400 metre horizontal laterals and completed with approximately 130 frac stages per well. This compares to 1,500 metre horizontal lengths and 28-41 frac stages utilized during the delineation phase. Testing of the wells will be completed in November and wells will start producing soon thereafter.

The drilling of the initial pad is the first step in our long-term plan to develop our existing land base, with an intermediate goal of achieving production of 30,000 boe/d within the next 5 years.

Financial

Leucrotta ended Q3 2021 with $45.5 million of adjusted working capital and no debt. We anticipate that Leucrotta will end 2022 with no debt and >$25 million of adjusted working capital.

SUMMARY OF FINANCIAL RESULTS

	Three Months Ended September 30			Nine Months Ended September 30		
($000s, except per share amounts)	**2021**	2020	% Change	**2021**	2020	% Change
Oil and natural gas sales	**6,954**	5,841	19	**23,854**	17,071	40
Cash flow from operating activities	**967**	368	163	**5,142**	975	427
Per share - basic and diluted	**-**	-	-	**0.02**	-	100
Adjusted funds flow (1)	**1,939**	586	231	**6,595**	548	1,103
Per share - basic and diluted	**0.01**	-	100	**0.03**	-	100
Net earnings (loss)	**66,545**	(2,525)	(2,735)	**66,120**	(94,158)	(170)
Per share - basic and diluted	**0.27**	(0.01)	(2,800)	**0.29**	(0.47)	(162)
Total assets				**307,275**	222,692	38
Total long-term liabilities				**14,249**	15,205	(6)
Adjusted working capital (deficiency) (2)				**45,503**	(4,421)	(1,129)

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

(2) Adjusted working capital (deficiency) includes current assets less current liabilities excluding the effects of any current portion of risk management contracts. Adjusted working capital (deficiency) 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 for more details.

The Company experienced a significant increase in oil and natural gas sales, cash flow from operating activities, and adjusted funds flow for the three and nine months ended September 30, 2021 compared to the same periods in 2020 mainly due to rising commodity prices (see discussion below).

The large net loss in the nine months ended September 30, 2020 was due to the impairment charge of $87.9 million recorded in Q1 2020 and the large net earnings in the three and nine months ended September 30, 2021 was due to the impairment reversal of $66.4 million.

PRODUCTION	Three Months Ended September 30			Nine Months Ended September 30		
	2021	2020	% Change	**2021**	2020	% Change
Average Daily Production (1)						
Oil and condensate (bbls/d)	**299**	542	(45)	**390**	648	(40)
Other NGLs (bbls/d)	**26**	248	(90)	**34**	278	(88)
Oil and NGLs (bbls/d)	**325**	790	(59)	**424**	926	(54)
Natural gas (mcf/d)	**8,953**	13,739	(35)	**10,840**	14,036	(23)
Oil equivalent (boe/d)	**1,817**	3,080	(41)	**2,231**	3,266	(32)

(1) "Natural gas" refers to shale gas; "Oil and condensate" refers to condensate, light and medium crude oil, and tight oil combined; "Other NGLs" refers to butane, propane and ethane combined; "Oil and NGLs" refers to light and medium crude oil, tight oil, and NGLs combined, "Oil equivalent" refers to the total oil equivalent of shale gas, light and medium crude oil, tight oil, and NGLs combined, using the conversion rate of six thousand cubic feet of shale gas to one barrel of oil equivalent as described above. Readers are referred to the "Product Types" section for a complete breakdown of sales volumes for applicable periods by specific product types of shale gas, light and medium crude oil, tight oil, and NGLs.

Daily production decreased to 1,817 boe/d and 2,231 boe/d for the three and nine months ended September 30, 2021, respectively, from 3,080 boe/d and 3,266 boe/d for the comparative periods in 2020. The decrease in production was the result of the sale of certain natural gas assets in Doe, BC in Q2 2021 which were producing approximately 375 boe/d and facility turnarounds in Q3 2021. Furthermore, the comparative periods of 2020 had flush oil production from Two Rivers, BC wells brought on production in March 2020.

Leucrotta's production profile for the third quarter of 2021 shifted in favour of natural gas from the comparative quarter in 2020 (production profile was consistent with Q2 2021). The Q3 2021 weighting was 82% natural gas (Q3 2020 - 74%) and 18% oil and NGLs (Q3 2020 - 26%). The shift of weighting from oil and NGLs to natural gas was due to new marketing agreements in which lower priced butane and propane NGL volumes are no longer being extracted from the natural gas sales volumes leading to higher heat content natural gas being sold into the Chicago market.

OIL AND NATURAL GAS SALES	Three Months Ended September 30			Nine Months Ended September 30		
($000s)	**2021**	2020	% Change	**2021**	2020	% Change
Oil and condensate	**2,241**	2,253	(1)	**7,749**	6,542	18
Other NGLs	**85**	524	(84)	**284**	1,529	(81)
Oil and NGLs	**2,326**	2,777	(16)	**8,033**	8,071	(-)
Natural gas	**4,628**	3,064	51	**15,821**	9,000	76
Total	**6,954**	5,841	19	**23,854**	17,071	40
Average Sales Price						
Oil and condensate ($/bbl)	**81.52**	45.19	80	**72.70**	36.87	97
Other NGLs ($/bbl)	**34.91**	22.95	52	**30.68**	20.04	53
Oil and NGLs ($/bbl)	**77.74**	38.21	103	**69.34**	31.81	118
Natural gas production sales and transportation revenue ($/mcf)	**5.62**	2.42	132	**5.35**	2.34	129
Combined ($/boe)	**41.59**	20.62	102	**39.16**	19.08	105

Oil and natural gas sales totaled $7.0 million and $23.9 million for the three and nine months ended September 30, 2021, respectively, compared to $5.8 million and $17.1 million for the comparative periods in 2020. The increase was due to the large rise in oil and condensate, other NGLs, and natural gas commodity prices partially offset by production declines. The large increase in commodity prices is primarily due to the global economic recovery and the return of energy demand as jurisdictions around the world ease restrictions in the post COVID-19 pandemic environment.

PROCESSING REVENUE	Three Months Ended September 30			Nine Months September 30		
($000s)	**2021**	2020	% Change	**2021**	2020	% Change
Processing revenue	**156**	178	(12)	**683**	312	119

Processing revenue relates to fees received from third parties for gas processed through the Company's gas plant. The large increase in the three and nine months ended September 30, 2021 over the comparative periods in 2020 was due to high commodity prices for natural gas received which also impacted demand for processing and processing fees received.

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

Commodity Pricing	Three Months Ended September 30			Nine Months Ended September 30		
	2021	2020	% Change	**2021**	2020	% Change
Oil and NGLs						
Corporate price ($CDN/bbl)	**77.74**	38.21	103	**69.34**	31.81	118
Canadian light sweet ($CDN/bbl)	**84.18**	49.05	72	**76.37**	44.13	73
West Texas Intermediate ("WTI") ($US/bbl)	**70.56**	40.93	72	**64.82**	38.32	69
Natural gas						
Corporate price ($CDN/mcf)	**5.62**	2.42	132	**5.35**	2.34	129
AECO price ($CDN/mcf)	**3.58**	2.27	58	**3.27**	2.10	56
Chicago City Gate ($US/mmbtu)	**4.14**	1.85	124	**3.99**	1.74	129
Exchange rate						
CDN/US dollar exchange rate	**0.7939**	0.7510	6	**0.7994**	0.7392	8

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 sales points and marketing contracts negotiated for products, the mix of oil and NGLs, and various other factors. Leucrotta's differences are mainly the result of higher heat content natural gas production that is priced higher than AECO reference prices as well as the diversification of sales points and marketing contracts for products.

The Company's corporate average oil and NGLs prices were 92.3% and 90.8% of Canadian light sweet prices for the three and nine months ended September 30, 2021, respectively, compared to 77.9% and 72.1% for the comparative periods in 2020. The increase was the result of the new marketing agreements described earlier in which lower priced butane and propane NGL volumes are no longer being extracted from the natural gas sales volumes leading to higher heat content natural gas being sold into the Chicago market. Leucrotta's liquids mix during the third quarter of 2021 was approximately 91% oil, condensate and pentanes, 5% butane and 4% propane (Q3 2020 - 69% oil, condensate and pentanes, 11% butane and 20% propane).

Corporate average natural gas prices were 107.8% and 107.2% of Chicago City Gate price (converted to Canadian dollars) for the three and nine months ended September 30, 2021, respectively, up from 98.2% and 99.4% for the comparative periods in 2020 due to selling higher heat content natural gas into the Chicago market as described above.

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.

At September 30, 2021, the Company had the following commodity price contracts outstanding:

Commodity	Period	Type of Contract	Quantity	Contract Price
Oil	October 1, 2021 - December 31, 2021	Financial - Swap	80 bbls/d	WTI CDN $59.60/bbl
Oil	October 1, 2021 - December 31, 2021	Financial - Swap	70 bbls/d	WTI CDN $90.10/bbl
Oil	January 1, 2022 - March 31, 2022	Financial - Swap	150 bbls/d	WTI CDN $88.00/bbl
Natural Gas	October 1, 2021 - December 31, 2021	Financial - Swap	2,900 MMBtu/d	Chicago NGI USD $2.6325/MMBtu
Natural Gas	October 1, 2021 - December 31, 2021	Financial - Swap	2,100 MMBtu/d	Chicago NGI USD $5.0100/MMBtu

For the three and nine months ended September 30, 2021, the realized loss on the risk management contracts was $0.6 million (September 30, 2020 - $nil) and $1.4 million (September 30, 2020 - $nil), respectively, and the unrealized loss was $0.6 million (September 30, 2020 - $nil) and $1.8 million (September 30, 2020 - $nil), respectively.

ROYALTIES	Three Months Ended September 30			Nine Months Ended September 30		
($000s)	**2021**	2020	% Change	**2021**	2020	% Change
Oil and NGLs	**347**	141	146	**1,045**	377	177
Natural gas	**413**	75	451	**1,200**	187	542
Total	**760**	216	252	**2,245**	564	298
Average Royalty Rate (% of sales)						
Oil and NGLs	**14.9**	5.1	192	**13.0**	4.7	177
Natural gas	**8.9**	2.4	271	**7.6**	2.1	262
Combined	**10.9**	3.7	195	**9.4**	3.3	185

The Company pays royalties to provincial governments (Crown) 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.

Royalties totaled $0.8 million and $2.2 million for the three and nine months ended September 30, 2021, respectively, compared to $0.2 million and $0.6 million for the comparative periods in 2020. The large increase for three and the nine months ended September 30, 2021 stems from higher natural gas prices resulting in higher natural gas royalties and the quicker utilization of available credits, which were used to reduce royalties otherwise payable on all commodities.

During the three and nine months ended September 30, 2021, the Company realized credits of $0.1 million (September 30, 2020 - $0.3 million) and $0.7 million (September 30, 2020 - $0.5 million), respectively, to offset royalties payable. These credits stem from the British Columbia Government's Infrastructure Royalty Credit Program resulting from infrastructure built and wells drilled and tied-into the related infrastructure and the Company has $nil credits remaining.

Further credits to reduce royalties are expected in the future as royalties continue to be payable on wells already tied-in to completed and approved infrastructure projects and as new infrastructure is built and wells are drilled and tied-into related infrastructure that was approved for credits under the program and become royalty payable. The timing of receipt of future credits is dependent on commodity prices and production levels and thus cannot be readily forecast; correspondingly, royalty rates reported in future quarters will fluctuate, likely materially, as these credits are recognized. This credit program is in addition to BC's Natural Gas Deep Well Royalty Credit Program where the Company currently has $0.4 million in remaining royalty credits.

NET OPERATING EXPENSES	**Three Months Ended September 30**			**Nine Months Ended September 30**		
($000s)	**2021**	2020	% Change	**2021**	2020	% Change
Oil and NGLs	**275**	741	(63)	**1,073**	2,504	(57)
Natural gas	**867**	1,488	(42)	**3,264**	4,115	(21)
Operating expenses	**1,142**	2,229	(49)	**4,337**	6,619	(34)
Less: processing revenue	**(156)**	(178)	(12)	**(683)**	(312)	119
Net operating expenses (non-GAAP)	**986**	2,051	(52)	**3,654**	6,307	(42)
Average net operating expenses						
Oil and NGLs ($/bbl)	**9.17**	10.19	(10)	**9.26**	9.87	(6)
Natural gas ($/mcf)	**0.86**	1.04	(17)	**0.87**	0.99	(12)
Combined ($/boe)	**5.89**	7.24	(19)	**6.00**	7.05	(15)

Per unit net operating expenses were $5.89/boe and $6.00/boe for the three and nine months ended September 30, 2021, respectively, down from $7.24/boe and $7.05/boe in the comparative periods in 2020. The decrease is mainly the result of higher processing revenue received stemming from the higher natural gas prices in 2021 creating more processing demand and higher processing fees.

TRANSPORTATION AND MARKETING EXPENSES	**Three Months Ended September 30**			**Nine Months Ended September 30**		
($000s)	**2021**	2020	% Change	**2021**	2020	% Change
Oil and NGLs transportation	**22**	24	(8)	**92**	214	(57)
Natural gas transportation	**1,015**	1,827	(44)	**4,131**	6,001	(31)
Transportation and marketing expenses	**1,037**	1,851	(44)	**4,223**	6,215	(32)
Average transportation and marketing expenses						
Oil and NGLs ($/bbl)	**0.74**	0.32	131	**0.80**	0.84	(5)
Natural gas ($/mcf)	**1.23**	1.45	(15)	**1.40**	1.56	(10)
Combined ($/boe)	**6.20**	6.53	(5)	**6.93**	6.95	(-)

Transportation and marketing expenses are mainly third-party pipeline tariffs from firm transportation agreements to deliver production to the purchasers at main hubs. Transportation and marketing expenses remained consistent on a per boe basis at $6.20/boe and $6.93/boe for the three and nine months ended September 30, 2021, respectively, compared to $6.53/boe and $6.95/boe for the comparative periods in 2020.

OPERATING NETBACK	Three Months Ended September 30			Nine Months Ended September 30		
	2021	2020	% Change	**2021**	2020	% Change
Oil and NGLs ($/bbl)						
Revenue	**77.74**	38.21	103	**69.34**	31.81	118
Royalties	**(11.61)**	(1.93)	502	**(9.02)**	(1.49)	505
Net operating expenses	**(9.17)**	(10.19)	(10)	**(9.26)**	(9.87)	(6)
Transportation and marketing expenses	**(0.74)**	(0.32)	131	**(0.80)**	(0.84)	(5)
Operating netback	**56.22**	25.77	118	**50.26**	19.61	156
Natural gas ($/mcf)						
Revenue	**5.62**	2.42	132	**5.35**	2.34	129
Royalties	**(0.50)**	(0.06)	733	**(0.41)**	(0.05)	720
Net operating expenses	**(0.86)**	(1.04)	(17)	**(0.87)**	(0.99)	(12)
Transportation and marketing expenses	**(1.23)**	(1.45)	(15)	**(1.40)**	(1.56)	(10)
Operating netback (loss)	**3.03**	(0.13)	(2,431)	**2.67**	(0.26)	(1,127)
Combined ($/boe)						
Revenue	**41.59**	20.62	102	**39.16**	19.08	105
Royalties	**(4.55)**	(0.76)	499	**(3.69)**	(0.63)	486
Net operating expenses	**(5.89)**	(7.24)	(19)	**(6.00)**	(7.05)	(15)
Transportation and marketing expenses	**(6.20)**	(6.53)	(5)	**(6.93)**	(6.95)	(-)
Operating netback	**24.95**	6.09	310	**22.54**	4.45	407

During the three and nine months ended September 30, 2021, Leucrotta generated an operating netback of $24.95/boe and $22.54/boe, respectively, up significantly from $6.09/boe and $4.45/boe for the comparative periods in 2020 mainly due to rising commodity prices. Oil and condensate, other NGLs and natural gas commodity prices rose a combined 102% and 105% in the three and nine months ended September 30, 2021, respectively, compared to the same periods in 2020.

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

	Three Months Ended September 30			Nine Months Ended September 30		
($/boe)	**2021**	2020	% Change	**2021**	2020	% Change
Operating netback	**24.95**	6.09	310	**22.54**	4.45	407
Depletion and depreciation	**(7.67)**	(10.08)	(24)	**(7.94)**	(8.82)	(10)
Asset (impairment) reversal	**397.21**	-	100	**109.04**	(98.22)	(211)
General and administrative expenses	**(6.78)**	(3.94)	72	**(6.96)**	(3.77)	85
Share based compensation	**(2.26)**	(0.64)	253	**(2.59)**	(0.31)	735
Gain on sale of assets	**-**	-	-	**-**	1.68	(100)
Finance expense	**(0.63)**	(0.33)	91	**(0.57)**	(0.25)	128
Finance income	**0.38**	-	100	**0.29**	-	100
Realized loss on risk management contracts	**(3.72)**	-	100	**(2.35)**	-	100
Unrealized loss on risk management contracts	**(3.67)**	-	100	**(2.97)**	-	100
Deferred income tax recovery	**0.20**	-	100	**0.06**	-	100
Net earnings (loss)	**398.01**	(8.90)	(4,572)	**108.55**	(105.24)	(203)

DEPLETION AND DEPRECIATION	Three Months Ended September 30			Nine Months Ended September 30		
	2021	2020	% Change	**2021**	2020	% Change
Depletion and depreciation ($000s)	**1,283**	2,858	(55)	**4,835**	7,893	(39)
Depletion and depreciation ($/boe)	**7.67**	10.08	(24)	**7.94**	8.82	(10)

The Company calculates depletion on property, plant, and equipment (“PP&E”) mainly based on proved plus probable reserves. Depletion and depreciation for the three and nine months ended September 30, 2021 decreased to $1.3 million (September 30, 2020 - $2.9 million) and $4.8 million (September 30, 2020 - $7.9 million) as a result of the impairments taken in Q1 2020 and Q4 2020. On a per boe basis, depletion and depreciation for the three and nine months ended September 30, 2021 decreased to $7.67/boe and $7.94/boe, respectively, from $10.08/boe and $8.82/boe for the comparative periods in 2020.

Included in depletion and depreciation expense for the three and nine months ended September 30, 2021, is $23 thousand (September 30, 2020 - $23 thousand) and $68 thousand (September 30, 2020 - $68 thousand), respectively, related to the right-of-use asset for the Company’s head office lease and $nil (September 30, 2020 - $0.5 million) and $nil (September 30, 2020 - $0.9 million), respectively, related to land lease expiries.

IMPAIRMENT OF PROPERTY, PLANT, AND EQUIPMENT AND EXPLORATION AND EVALUATION ASSETS

At September 30, 2021, the Company evaluated its PP&E Montney CGU for indicators of impairment or impairment reversals. At September 30, 2021, indicators of impairment reversal were determined to exist in the Company’s Montney CGU primarily as a result of significant and sustained increase in forward commodity benchmark prices for oil and condensate, natural gas and other NGLs.

The recoverable amount of the Company's Montney CGU, comprised of primarily natural gas and NGLs reserves, was determined using the value in use methodology based on the net present value of cash flows from oil and natural gas reserves at pre-tax discount rates ranging from 10 to 20 percent depending on the underlying composition and risk profile of the reserve category. At September 30, 2021, the Company determined that the recoverable amount of $117.3 million, net of associated decommissioning obligations, of the Company's Montney CGU exceeded the carrying amount and accordingly, an impairment reversal of $66.4 million was recorded.

At September 30, 2021, the Company evaluated its exploration and evaluation assets for indicators of impairment or impairment reversals and as a result of this assessment management determined that an impairment test was not required to be performed.

At December 31, 2020, the Company evaluated its Montney CGU for indicators of impairment or impairment reversals. The Company made the decision to reduce its Future Development Capital ("FDC") and long dated developments to better match the go forward development plan. As a result of this re-alignment, indicators of impairment were determined to exist in the Company's Montney CGU as a result of reducing the reserve bookings and FDC for the Upper Montney at Doe and for the Lower Montney at Two Rivers East where significant drilling and infrastructure capital would be required and is not anticipated at the current time.

The recoverable amount of the Montney CGU was determined using the value in use methodology based on the net present value of cash flows from oil and natural gas reserves at pre-tax discount rates ranging from 10 to 20 percent depending on the underlying composition and risk profile of the reserve category. The oil and natural gas commodity price estimates used in the impairment test were based on an average of three independent third party reserve evaluators. At December 31, 2020, the Company determined that the carrying amount of the Company's Montney CGU exceeded the recoverable amount, net of associated decommissioning obligations, of $66.8 million and accordingly, an impairment charge of $13.5 million was recorded.

At December 31, 2020, the Company evaluated its exploration and evaluation assets for indicators of impairment or impairment reversals and as a result of this assessment management determined that an impairment test was not required to be performed.

At March 31, 2020, indicators of impairment were determined to exist in the Company's Montney CGU primarily as a result of significant and sustained declines in forward commodity benchmark prices for oil, natural gas and NGLs and a sustained market capitalization deficiency relative to the book value of the Company's shareholders' equity.

The recoverable amount of the Company's Montney CGU was determined using the value in use methodology based on the net present value of cash flows from oil and natural gas reserves at pre-tax discount rates ranging from 10 to 17.5 percent depending on the underlying composition and risk profile of the reserve category. The oil and natural gas commodity price estimates used in the impairment test were based on an average of three independent third party reserve evaluators. At March 31, 2020, the Company determined that the carrying amount of the Company's Montney CGU exceeded the recoverable amount, net of associated decommissioning obligations, of $86.5 million and accordingly, an impairment charge of $84.8 million was recorded. An additional $2.4 million of impairment was recorded prior to the transfer of certain assets from exploration and evaluation assets to PP&E and an additional $0.7 million of impairment was recorded upon transfer of certain assets to assets held for sale for a total impairment expense of $87.9 million for the three months ended March 31, 2020.

GENERAL AND ADMINISTRATIVE	**Three Months Ended September 30**			**Nine Months Ended September 30**		
($000s)	**2021**	2020	% Change	**2021**	2020	% Change
G&A expenses (gross)	**1,366**	1,122	22	**4,525**	3,548	28
G&A capitalized	**(231)**	(6)	3,750	**(286)**	(174)	64
G&A recoveries	**(3)**	-	100	**(5)**	(2)	150
G&A expenses (net)	**1,132**	1,116	1	**4,234**	3,372	26
G&A expenses ($/boe)	**6.78**	3.94	72	**6.96**	3.77	85

General and administrative ("G&A") expenses were $6.78/boe and $6.96/boe for the three and nine months ended September 30, 2021, respectively, compared to $3.94/boe and $3.77/boe for the comparative periods in 2020. G&A expenses in the first nine months of 2021 increased as the result of increased legal costs, director fees and bad debts expense. This increase was more pronounced on a per boe basis as production declined from the sale of certain natural gas assets in Doe, BC.

SHARE BASED COMPENSATION	**Three Months Ended September 30**			**Nine Months Ended September 30**		
	2021	2020	% Change	**2021**	2020	% Change
Share based compensation ($000s)	**380**	181	110	**1,580**	279	466
Share based compensation ($/boe)	**2.26**	0.64	253	**2.59**	0.31	735

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 granted to officers, directors, employees, and consultants with a corresponding increase to contributed surplus.

Share based compensation expense increased to $0.4 million and $1.6 million for the three and nine months ended September 30, 2021, respectively, compared to $0.2 million and $0.3 million for the comparative periods in 2020. The increase in expense is mainly due to using the graded (accelerated) amortization method whereby more expense is recognized earlier in the stock option's life. 7.0 million stock options were granted during Q3 2020 and another 4.8 million stock options were granted during the nine months ended September 30, 2021, contributing to the large increase in share based compensation for 2021. The Company also recorded a one-time share based compensation charge of $0.4 million upon the issuance of flow-through common shares and flow-through warrants to certain officers and directors of the Company in Q2 2021 as the fair value of the flow-through unit received exceeded the price paid.

FINANCE EXPENSE	**Three Months Ended September 30**			**Nine Months Ended September 30**		
($000s)	**2021**	2020	% Change	**2021**	2020	% Change
Interest expense	**43**	63	(32)	**177**	110	61
Accretion of decommissioning obligations	**63**	30	110	**171**	116	47
Finance expense	**106**	93	14	**348**	226	54
Finance expense ($/boe)	**0.63**	0.33	91	**0.57**	0.25	128

Interest expense includes interest payments on the credit facility and the interest expense on lease obligations. Interest expense increased during the nine months ended September 30, 2021 compared to the same period in 2020 due to the Company drawing more on the credit facility in the first three months in 2021 compared to 2020. Interest expense decreased significantly for the three months ended September 30, 2021 compared to the same period in 2020 after receiving the proceeds on equity financings and the sale of certain natural gas assets.

Accretion expense increased for the three and nine months ended September 30, 2021 compared to the same periods in 2020 mainly as the result of increasing interest and inflation rates.

FINANCE INCOME

Finance income relates to interest earned on cash in the bank. Finance income for the three and nine months ended September 30, 2021, totaled $0.1 million (September 30, 2020 - $nil) and $0.2 million (September 30, 2020 - $3 thousand), respectively. The increase corresponds to the increase in the Company's cash balance over the comparative periods due to the equity financings and the sale of certain natural gas assets during the first nine months of 2021.

DEFERRED INCOME TAXES

The Company has not realized the net deferred income tax asset as it is not probable that future taxable profits, based on the estimated cash flows derived from the independently evaluated reserve report, would be sufficient to realize the deferred income tax asset at this time.

Estimated tax pools at September 30, 2021 total approximately $310.6 million (December 31, 2020 - $325.8 million).

CASH FLOW FROM OPERATING ACTIVITIES AND ADJUSTED FUNDS FLOW

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

	Three Months Ended September 30			**Nine Months Ended September 30**		
($000s)	**2021**	2020	% Change	**2021**	2020	% Change
Cash flow from operating activities	**967**	368	163	**5,142**	975	427
Add (deduct):						
Transaction costs on property disposition	**-**	-	-	**750**	-	100
Decommissioning expenditures	**9**	27	(67)	**51**	105	(51)
Change in non-cash working capital	**963**	191	404	**652**	(532)	(223)
Adjusted funds flow (non-GAAP)	**1,939**	586	231	**6,595**	548	1,103

Adjusted funds flow was $1.9 million ($0.01 per basic and diluted share) and $6.6 million ($0.03 per basic and diluted share) for the three and nine months ended September 30, 2021, respectively, compared to $0.6 million ($nil per basic and diluted share) and $0.6 million ($nil per basic and diluted share) for the comparative periods in 2020. The increase was mainly due to the large rise in oil and condensate, other NGLs, and natural gas commodity prices primarily due to the global economic recovery and the return of energy demand as jurisdictions around the world ease restrictions in the post COVID-19 pandemic environment.

Cash flow from operating activities increased for the three and nine months ended September 30, 2021 to $1.0 million ($nil per basic and diluted share) and $5.1 million ($0.02 per basic and diluted share), respectively, from $0.4 million ($nil per basic and diluted share) and $1.0 million ($nil per basic and diluted share) for the comparative periods in 2020. The increase period over period is due to similar reasons as stated above. Cash flow from operating activities differs from adjusted funds flow due to the inclusion of changes in non-cash working capital, expenditures on decommissioning obligations and transaction costs on property dispositions.

NET EARNINGS (LOSS)

Net earnings for the three and nine months ended September 30, 2021 increased to $66.5 million ($0.27 per basic and diluted share) and $66.1 million ($0.29 per basic and diluted share), respectively, compared to net losses of $2.5 million ($0.01 per basic and diluted share) and $94.2 million ($0.47 per basic and diluted share) for the comparative periods in 2020. Along with significantly higher cash flow from operating activities in both the three and nine months ended September 30, 2021 compared to the same periods in 2020, the large net earnings in the three and nine months ended September 30, 2021 was due to the reversal of impairment of $66.4 million. The large net loss in the nine months ended September 30, 2020 was the result of the impairment charge of $87.9 million recorded in Q1 2020.

CAPITAL EXPENDITURES	Three Months Ended September 30			Nine Months Ended September 30		
($000s)	**2021**	2020	% Change	**2021**	2020	% Change
Land	**224**	246	(9)	**513**	869	(41)
Drilling, completions, and workovers	**11,140**	55	20,155	**14,468**	5,817	149
Equipment	**2,509**	300	736	**3,075**	6,512	(53)
Geological and geophysical	**108**	46	135	**159**	123	29
Total expenditures	**13,981**	647	2,061	**18,215**	13,321	37
Proceeds on sale of properties and equipment	**-**	-	-	**30,000**	8,206	266

During the first nine months of 2021, the Company drilled its 4-well test pad at Mica, BC utilizing longer laterals and will use materially greater frac intensity in its completions scheduled for Q4 2021. The Company also completed its Basal Montney well at Mica, BC that was previously drilled in Q1 2019.

On April 1, 2021, the Company disposed of certain natural gas assets located in Doe, BC for gross proceeds of $30.0 million ($29.25 million net of transaction costs). The disposed assets were comprised of 10.25 sections of non-strategic lands with three wells producing approximately 375 boe/d and one shut-in well.

The Company halted capital expenditures in Q2 2020 after completing the Two Rivers, BC facility due to the negative global impact of COVID-19 on commodity prices. During the first nine months of 2020, Company drilled, completed and tied-in a second Montney well at Two Rivers. The Company also completed construction of the Two Rivers facility and commenced production of two Montney wells (B16-05 drilled and completed in Q1 2020 and A10-08 drilled and completed in Q4 2017). During Q2 2020, the Company received proceeds of $6.0 million from a third party related to the Two Rivers property and lands and proceeds of $2.2 million and future operating credits of $1.5 million related to the sale of certain non-core facility assets.

LIQUIDITY AND CAPITAL RESOURCES

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

($000s)	**September 30, 2021**	December 31, 2020	% Change
Current assets	**53,419**	4,070	1,213
Less:			
Current liabilities	**(9,578)**	(9,730)	(2)
Working capital (deficiency)	**43,841**	(5,660)	(875)
Less: Risk management contracts liability (asset)	**1,662**	(147)	(1,231)
Adjusted working capital (deficiency) (non-GAAP)	**45,503**	(5,807)	(884)

At September 30, 2021, the Company had adjusted working capital of $45.5 million.

During the nine months ended September 30, 2021, the Company entered into a credit agreement with a new lender comprised of a $10.0 million revolving operating demand loan credit facility. The new credit agreement fully replaced the previous $6.0 million credit facility, which was comprised of a $2.0 million demand loan facility and $4.0 million demand letter of credit facility. The revolving credit facility bears interest at prime plus a range of 1.75% to 3.75% and is secured by a floating charge debenture on all the assets of the Company. The undrawn portion of the credit facility is subject to a standby fee in the range of 0.75% to 1.25%. The new 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 lender, 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 definition of current assets and current liabilities excludes unrealized risk management contracts. The Company was compliant with this covenant at September 30, 2021. The next review of the credit facility by the lender is scheduled to occur on or before November 30, 2021.

At September 30, 2021, $nil had been drawn on the credit facility (December 31, 2020 - $5.8 million). At September 30, 2021, the Company had outstanding letters of guarantee of $3.5 million which reduce the amount that can be borrowed under the credit facility.

The Company has $1.4 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 President's margin account holds $2.4 million of securities of Leucrotta common shares and a margin payable of $1.4 million. The cross-guarantee is not intended to be long-term in nature and will be removed as soon as practicable. The cross-guarantee has allowed the President to comply with corporate governance mandates. The $1.4 million has been segregated on the statement of financial position as restricted cash at September 30, 2021 (December 31, 2020 - $1.4 million).

Management anticipates that the Company will continue to have adequate liquidity to fund budgeted capital investments through a combination of its 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. On March 31, 2021, the Company closed a bought-deal public financing for gross proceeds of $33.0 million and on April 1, 2021, the Company closed its disposition of certain natural gas assets for gross proceeds of $30.0 million.

CONTRACTUAL OBLIGATIONS

The following is a summary of the Company's contractual obligations and commitments at September 30, 2021:

($000s)	Total	Less than One Year	One to Three Years	After Three Years
Accounts payable and accrued liabilities	7,733	7,733	-	-
Lease obligations	8	8	-	-
Risk management contracts	1,662	1,662	-	-
Onerous contract	175	175	-	-
Decommissioning obligations	14,249	-	815	13,434
Operating commitments	1,006	33	359	614
Firm transportation agreements	17,036	6,687	10,066	283
Total contractual obligations	41,869	16,298	11,240	14,331

Transportation commitments include contracts to transport natural gas and NGLs through third-party owned pipeline systems. The Company currently has commitments of 13.4 mmcf/d of firm transportation to deliver natural gas to the Alliance Trading Pool (ATP) through October 31, 2023. The Company has also committed to 14.2 mmcf/d of firm transportation to deliver natural gas to Chicago through October 31, 2024.

Operating commitments include the non-lease variable components of the head office lease.

During the three months ended September 30, 2021, the Company signed a new head office lease beginning December 1, 2021 to November 30, 2027, with the first year of the lease comprising a rent-free period. Base rent averages $126 thousand per year and operating expenses are anticipated to be approximately $194 thousand per year. The Company will recognize a lease liability and related right-of-use asset on commencement of the lease.

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 other than the fixed payment component of the head office lease have been treated as operating commitments 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)	**September 30, 2021**	November 15, 2021
Voting common shares	**247,641**	247,641
Warrants	**24,473**	24,473
Stock options	**17,997**	16,031
Total	**290,111**	288,145

SUMMARY OF QUARTERLY RESULTS

	Q3 2021	Q2 2021	Q1 2021	Q4 2020	Q3 2020	Q2 2020	Q1 2020	Q4 2019
Average Daily Production								
Oil and NGLs (bbls/d)	**325**	431	519	645	790	1,128	862	765
Natural gas (mcf/d)	**8,953**	10,559	13,053	13,508	13,739	16,019	12,354	12,392
Oil equivalent (boe/d)	**1,817**	2,191	2,695	2,897	3,080	3,797	2,921	2,830
($000s, except per share amounts)								
Oil and natural gas sales	**6,954**	6,426	10,474	6,515	5,841	5,439	5,791	6,870
Cash flow from (used in)								
operating activities	**967**	(744)	4,919	212	368	(798)	1,405	2,098
Per share - basic and diluted	**-**	(-)	0.02	-	-	(-)	0.01	0.01
Adjusted funds flow (used) (1)	**1,939**	866	3,790	807	586	(798)	760	2,316
Per share - basic and diluted	**0.01**	-	0.02	-	-	(-)	-	0.01
Net (loss) earnings	**66,545**	(1,592)	1,167	(16,697)	(2,525)	(2,189)	(89,444)	(6,140)
Per share - basic and diluted	**0.27**	(0.01)	0.01	(0.08)	(0.01)	(0.01)	(0.45)	(0.03)

(1) Adjusted funds flow (used) and adjusted funds flow (used) per share do not have any standardized meaning prescribed by IFRS and therefore may not be comparable to similar measures used by other companies. Please refer to the “Non-GAAP Measures” section for more details and the “Cash Flow From Operating Activities and Adjusted Funds Flow” section for a reconciliation from cash flow from operating activities.

The Company experienced a significant increase in oil and natural gas sales, cash flow from operating activities, and adjusted funds flow for the first nine months of 2021 mainly due to rising oil and condensate, other NGLs and natural gas commodity prices. Production decreased in Q2 2021 due to the sale of certain natural gas assets in Doe, BC. Production increased in the second quarter of 2020 due to flush production from start-up at Two Rivers, BC. Production for the other quarters decreased due to natural declines. Oil and natural gas sales, cash flow from (used in) from operating activities and adjusted funds flow (used) generally followed the same trend as production with some exceptions based on volatility of commodity prices received. Declines in oil and condensate, other NGLs and natural gas commodity pricing throughout 2020 negatively affected cash flow from (used in) operating activities, adjusted funds flow (used) and net earnings (loss). The increased net losses in Q1 2020 and Q4 2020 were the result of impairment charges of $87.9 million and $13.5 million, respectively. The large increase in net earnings in Q3 2021 was the result of reversal of impairment of $66.4 million.

All accounting policies are consistent with those of the previous financial year. Refer to note 3 of the audited financial statements for the year ended December 31, 2020 for the Company’s significant accounting policies.

CRITICAL ACCOUNTING ESTIMATES

Management is required to make estimates, judgments, and assumptions in the application of IFRS that affect the reported amounts of assets and liabilities at the date of the financial statements and revenues and expenses for the period then ended. Certain of these estimates may change from period to period resulting in a material impact on the Company’s results from operations and financial position. See note 2d in the notes to the Company’s audited financial statements for the year ended December 31, 2020 for full descriptions of the use of estimates and judgments.

Coronavirus disease (COVID-19) estimation uncertainty

In early March 2020, the World Health Organization declared the COVID-19 coronavirus outbreak to be a global pandemic. The current and expected impacts on global commerce are anticipated to be far-reaching. To date there have been significant stock market declines and volatility, significant volatility in commodity and foreign exchange markets, restrictions on the conduct of business in many jurisdictions and the global movement of people and some goods have become restricted. There is significant ongoing uncertainty surrounding COVID-19 and the extent and duration of the impacts that it may have on demand and prices for the commodities Leucrotta produces, on its suppliers, on its employees and on global financial markets. The situation is dynamic and the ultimate duration and magnitude of the impact on the economy and the financial effect to the Company is not known at this time. Estimates and judgments made by management in the preparation of financial statements are subject to a higher degree of measurement uncertainty during this volatile period. In the current environment, assumptions about future commodity prices, exchange rates, and interest rates are subject to greater variability than normal, which could in the future significantly affect the valuation of Leucrotta's assets, both financial and non-financial. As an understanding of the longer-term impacts of COVID-19 on commodity, credit and equity markets develops, there is amplified potential for changes in estimates and judgments in the future.

RISK ASSESSMENT

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

Reserves and reserve replacement

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

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

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

Operational risks

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

Market risk

Market risk is the risk that the fair value of future cash flows of a financial instrument will fluctuate because of changes in market prices. Market risk is comprised of foreign currency risk, interest rate risk, and other price risk, such as commodity price risk. The objective of market risk management is to manage and control market price exposures within acceptable limits, while maximizing returns. The Company may use financial derivatives or physical delivery sales contracts to manage market risks. All such transactions are conducted within risk management tolerances that are reviewed by the Board of Directors. As required under the terms of the Company's credit facility, the Company is subject to an upper limit on fixed price contracts of 75% for the first year and 65% in the second year of its future production up to a two year period.

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

Interest rate risk
The Company is exposed to interest rate risk when it borrows funds at floating interest rates or has cash invested at floating rates. The Company currently does not use interest rate hedges or fixed interest rate contracts to manage the Company's exposure to interest rate fluctuations. The amount drawn on the Company's credit facility at September 30, 2021 was $nil.

Commodity price risk
Oil and natural gas prices are impacted by not only the relationship between the Canadian and US dollar but also by world economic events that dictate the levels of supply and demand. The Company's oil, natural gas, and NGLs production is marketed and sold on the spot market to area aggregators based on daily spot prices that are adjusted for product quality and transportation costs. The Company's cash flow from product sales will therefore be impacted by fluctuations in commodity prices. In addition, the Company may enter into commodity price contracts to manage future cash flows. At September 30, 2021, the Company had the following commodity price contracts outstanding:

Commodity	Period	Type of Contract	Quantity	Contract Price
Oil	October 1, 2021 - December 31, 2021	Financial - Swap	80 bbls/d	WTI CDN $59.60/bbl
Oil	October 1, 2021 - December 31, 2021	Financial - Swap	70 bbls/d	WTI CDN $90.10/bbl
Oil	January 1, 2022 - March 31, 2022	Financial - Swap	150 bbls/d	WTI CDN $88.00/bbl
Natural Gas	October 1, 2021 - December 31, 2021	Financial - Swap	2,900 MMBtu/d	Chicago NGI USD $2.6325/MMBtu
Natural Gas	October 1, 2021 - December 31, 2021	Financial - Swap	2,100 MMBtu/d	Chicago NGI USD $5.0100/MMBtu

Credit risk

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

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

The maximum exposure to credit risk is represented by the carrying amount of cash and cash equivalents, restricted cash, and accounts receivable on the statement of financial position. At September 30, 2021, $2.8 million (91%) of the Company's outstanding accounts receivable were current and $0.1 million (4%) were outstanding for more than 90 days. During the nine months ended September 30, 2021, the Company deemed $0.1 million of outstanding accounts receivable to be uncollectable (September 30, 2020 - $43 thousand).

Cash and cash equivalents and restricted cash consist of bank balances placed with financial institutions with strong investment grade ratings which management believes the risk of loss to be remote. The Company manages the credit risk exposure related to risk management contracts by selecting investment grade financial institution counterparties and by not entering into contracts for trading or speculative purposes.

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.

As at September 30, 2021, the Company has adjusted working capital of $45.5 million (see "Non-GAAP Measures") and $nil drawn on the $10.0 million credit facility (see "Liquidity and Capital Resources" section for more detail on the full credit facility). Management anticipates that the Company will continue to have adequate liquidity to fund budgeted capital investments through a combination of its cash flow, equity, and debt. On March 31, 2021, the Company closed a bought-deal public financing for gross proceeds of $33.0 million and on April 1, 2021, the Company closed its disposition of certain natural gas assets for gross proceeds of $30.0 million.

The global impact of COVID-19 as well as the recent declines in spot prices for oil have resulted in significant declines in financial markets and has forecasted a great deal of uncertainty. As a result, oil and gas companies are subject to liquidity risks in maintaining their revenues and earnings as well as ongoing and future development and operating expenditure requirements. These and other factors may adversely affect the Company's liquidity and the Company's ability to generate income and cash flows in the future. In light of the current volatility and difficulty in reliably estimating the length or severity of these developments, and hence their financial impact, the preparation of financial forecasts is challenging. At September 30, 2021, the Company remains in compliance with all terms of its credit facility and based on current available information, management expects to comply with all terms during at least the subsequent 12-month period.

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.

PRODUCT TYPES

The Company uses the following references to sales volumes in the MD&A:

Natural gas refers to shale gas
Oil and condensate refers to condensate, light and medium crude oil, and tight oil combined
Other NGLs refers to butane, propane and ethane combined
Oil and NGLs refers to light and medium crude oil, tight oil, and NGLs combined
Oil equivalent refers to the total oil equivalent of shale gas, light and medium crude oil, tight oil, and NGLs combined, using the conversion rate of six thousand cubic feet of shale gas to one barrel of oil equivalent as described above.

The following is a complete breakdown of sales volumes for applicable periods by specific product types of shale gas, light and medium crude oil, tight oil, and NGLs:

Sales Volumes by Product Type	Q1 2021	Q2 2021	Q3 2021	YTD Q3 2021
Condensate (bbls/d)	124	79	68	90
Other NGLs (bbls/d)	41	34	26	34
NGLs (bbls/d)	165	113	94	124
Light and medium crude oil (bbls/d)	-	-	-	-
Tight oil (bbls/d)	354	318	231	300
Condensate (bbls/d)	124	79	68	90
Oil and condensate (bbls/d)	478	397	299	390
Other NGLs (bbls/d)	41	34	26	34
Oil and NGLs (bbls/d)	519	431	325	424
Shale gas (mcf/d)	13,053	10,559	8,953	10,840
Natural gas (mcf/d)	13,053	10,559	8,953	10,840
Oil equivalent (boe/d)	2,695	2,191	1,817	2,231

Sales Volumes by Product Type	Q1 2020	Q2 2020	Q3 2020	YTD Q3 2020	Q4 2020	Q4 2019
Condensate (bbls/d)	144	166	145	153	125	151
Other NGLs (bbls/d)	271	317	248	278	94	265
NGLs (bbls/d)	415	483	393	431	219	416
Light and medium crude oil (bbls/d)	41	-	-	14	-	34
Tight oil (bbls/d)	406	645	397	481	426	315
Condensate (bbls/d)	144	166	145	153	125	151
Oil and condensate (bbls/d)	591	811	542	648	551	500
Other NGLs (bbls/d)	271	317	248	278	94	265
Oil and NGLs (bbls/d)	862	1,128	790	926	645	765
Shale gas (mcf/d)	12,354	16,019	13,739	14,036	13,508	12,392
Natural gas (mcf/d)	12,354	16,019	13,739	14,036	13,508	12,392
Oil equivalent (boe/d)	2,921	3,797	3,080	3,266	2,897	2,830

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 and condensate, other NGLs, and natural gas production, capital programs, adjusted working capital, and debt. The forward-looking statements and information are based on certain key expectations and assumptions made by the Company, including expectations and assumptions relating to prevailing commodity prices and exchange rates, applicable royalty rates and tax laws, future well production rates, the performance of existing wells, the success of drilling new wells, the availability of capital to undertake planned activities, and the availability and cost of labour and services.

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

ADDITIONAL INFORMATION

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

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

($000s)	Note	**September 30 2021**	December 31 2020
Assets			
Current assets			
Cash and cash equivalents		**48,250**	-
Restricted cash		**1,430**	1,430
Accounts receivable		**3,121**	2,099
Prepaid expenses and deposits		**618**	394
Risk management contracts	(12)	**-**	147
		53,419	4,070
Property, plant, and equipment	(4)	**131,505**	82,063
Exploration and evaluation assets	(5)	**121,530**	121,328
Deferred credits	(4)	**821**	925
		253,856	204,316
		307,275	208,386
Liabilities			
Current liabilities			
Accounts payable and accrued liabilities		**7,733**	2,113
Current portion of lease obligations	(6)	**8**	78
Risk management contracts	(12)	**1,662**	-
Onerous contract	(15)	**175**	1,751
Credit facility	(7)	**-**	5,788
		9,578	9,730
Decommissioning obligations	(8)	**14,249**	15,291
		23,827	25,021
Shareholders' Equity			
Shareholders' capital	(9)	**316,681**	288,837
Warrants	(9)	**4,648**	-
Contributed surplus		**21,852**	20,381
Deficit		**(59,733)**	(125,853)
		283,448	183,365
		307,275	208,386
Commitments	(15)		

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

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

($000s, except per share amounts)	Note	Three Months Ended September 30 **2021**	2020	Nine Months Ended September 30 **2021**	2020
Revenue					
Oil and natural gas sales	(14)	**6,954**	5,841	**23,854**	17,071
Processing and marketing	(14)	**156**	178	**683**	312
Royalties	(14)	**(760)**	(216)	**(2,245)**	(564)
		6,350	5,803	**22,292**	16,819
Realized loss on risk management contracts	(12)	**(622)**	-	**(1,429)**	-
Unrealized loss on risk management contracts	(12)	**(614)**	-	**(1,809)**	-
		5,114	5,803	**19,054**	16,819
Expenses					
Operating		**1,142**	2,229	**4,337**	6,619
Transportation and marketing		**1,037**	1,851	**4,223**	6,215
Depletion and depreciation	(4,5)	**1,283**	2,858	**4,835**	7,893
Asset impairment (reversal)	(4,5)	**(66,414)**	-	**(66,414)**	87,883
General and administrative		**1,132**	1,116	**4,234**	3,372
Share based compensation	(10)	**380**	181	**1,580**	279
Gain on sale of equipment	(4)	**-**	-	**-**	(1,507)
Finance income		**(63)**	-	**(175)**	(3)
Finance expense		**106**	93	**348**	226
		(61,397)	8,328	**(47,032)**	110,977
Earnings (loss) before taxes		**66,511**	(2,525)	**66,086**	(94,158)
Taxes					
Deferred income tax recovery	(9)	**34**	-	**34**	-
Net earnings (loss) and comprehensive earnings (loss)		**66,545**	(2,525)	**66,120**	(94,158)
Net earnings (loss) per share					
Basic and diluted	(11)	**0.27**	(0.01)	**0.29**	(0.47)

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

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

($000s)	Shareholders' Capital	Warrants	Contributed Surplus	Deficit	Total Equity
Balance, December 31, 2019	288,837	-	19,737	(14,998)	293,576
Net loss	-	-	-	(94,158)	(94,158)
Share based compensation	-	-	290	-	290
Balance, September 30, 2020	288,837	-	20,027	(109,156)	199,708
Balance, December 31, 2020	288,837	-	20,381	(125,853)	183,365
Net earnings	**-**	**-**	**-**	**66,120**	**66,120**
Issue of common shares, flow-through common shares, and warrants	**29,765**	**4,957**	**-**	**-**	**34,722**
Issue costs	**(1,933)**	**(309)**	**-**	**-**	**(2,242)**
Flow-through share premium	**(34)**	**-**	**-**	**-**	**(34)**
Exercise of stock options	**46**	**-**	**(14)**	**-**	**32**
Share based compensation	**-**	**-**	**1,485**	**-**	**1,485**
Balance, September 30, 2021	**316,681**	**4,648**	**21,852**	**(59,733)**	**283,448**

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

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

($000s)	Note	Three Months Ended September 30 2021	2020	Nine Months Ended September 30 2021	2020
Operating Activities					
Net earnings (loss)		**66,545**	(2,525)	**66,120**	(94,158)
Depletion and depreciation	(4,5)	**1,283**	2,858	**4,835**	7,893
Asset impairment (reversal)	(4,5)	**(66,414)**	-	**(66,414)**	87,883
Share based compensation	(10)	**380**	181	**1,580**	279
Finance expense		**106**	93	**348**	226
Interest paid		**(43)**	(63)	**(177)**	(110)
Payments on onerous contract	(15)	**(525)**	-	**(1,576)**	-
Use of deferred credits	(4)	**27**	42	**104**	42
Unrealized loss on risk management contracts	(12)	**614**	-	**1,809**	-
Gain on sale of equipment	(4)	**-**	-	**-**	(1,507)
Deferred income tax recovery	(9)	**(34)**	-	**(34)**	-
Transaction costs on property disposition	(4)	**-**	-	**(750)**	-
Decommissioning expenditures	(8)	**(9)**	(27)	**(51)**	(105)
Change in non-cash working capital	(13)	**(963)**	(191)	**(652)**	532
		967	368	**5,142**	975
Financing Activities					
Issue of common shares, flow-through common shares, and warrants	(9)	**-**	-	**34,365**	-
Issue costs	(9)	**-**	-	**(2,242)**	-
Credit facility	(7)	**-**	285	**(5,788)**	5,514
Payment of lease obligations	(6)	**(24)**	(22)	**(70)**	(67)
Exercise of stock options	(10)	**-**	-	**32**	-
		(24)	263	**26,297**	5,447
Investing Activities					
Capital expenditures - property, plant, and equipment	(4)	**(11,256)**	(447)	**(12,669)**	(6,760)
Capital expenditures - exploration and evaluation assets	(5)	**(2,725)**	(200)	**(5,546)**	(6,561)
Property dispositions	(4,5)	**-**	-	**30,000**	6,000
Sale of equipment	(4)	**-**	-	**-**	2,206
Change in non-cash working capital	(13)	**4,307**	16	**5,026**	(1,602)
		(9,674)	(631)	**16,811**	(6,717)
Change in cash and cash equivalents		**(8,731)**	-	**48,250**	(295)
Cash and cash equivalents, beginning of period		**56,981**	-	**-**	295
Cash and cash equivalents, end of period		**48,250**	-	**48,250**	-

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

1. REPORTING ENTITY

Leucrotta Exploration Inc. ("Leucrotta" or the "Company") is an oil and natural gas company, actively engaged in the acquisition, development, exploration, and production of oil and natural gas reserves in northeastern British Columbia, Canada. The Company's voting common shares are traded on the TSX Venture Exchange ("TSXV") under the symbol "LXE". The Company's place of business is located at 700, 639 - 5th Avenue SW, Calgary, Alberta, Canada, T2P 0M9.

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

2. BASIS OF PRESENTATION

(a) Statement of compliance

These condensed interim financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB") applicable to the preparation of interim financial statements, as prescribed by IAS 34, Interim Financial Reporting. The condensed interim financial statements do not include all of the information and disclosure required in annual financial statements and should be read in conjunction with the audited financial statements and related notes for the year ended December 31, 2020.

The condensed interim financial statements were authorized for issuance by the Board of Directors on November 15, 2021.

(b) Basis of measurement

The condensed interim financial statements have been prepared on the historical cost basis except for risk management contracts which are measured at fair value.

(c) Functional and presentation currency

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

(d) Use of estimates and judgments

The preparation of the condensed interim financial statements in conformity with IFRS requires management to make estimates and use judgment regarding the reported amounts of assets and liabilities as at the date of the condensed interim financial statements and the reported amounts of revenues and expenses during the period. By their nature, estimates are subject to measurement uncertainty and changes in such estimates in future periods could require a material change in the interim financial statements. Accordingly, actual results may differ from the estimated amounts as future confirming events occur. The significant estimates and judgments made by management in the preparation of these condensed interim financial statements were consistent with those applied to the financial statements as at and for the year ended December 31, 2020.

In early March 2020, the World Health Organization declared the COVID-19 coronavirus outbreak to be a global pandemic. The current and expected impacts on global commerce are anticipated to be far-reaching. To date there have been significant stock market declines and volatility, significant volatility in commodity and foreign exchange markets, restrictions on the conduct of business in many jurisdictions and the global movement of people and some goods have become restricted. There is significant ongoing uncertainty surrounding COVID-19 and the extent and duration of the impacts that it may have on demand and prices for the commodities Leucrotta produces, on its suppliers, on its employees and on global financial markets. The situation is dynamic and the ultimate duration and magnitude of the impact on the economy and the financial effect to the Company is not known at this time. Estimates and judgments made by management in the preparation of financial statements are subject to a higher degree of measurement uncertainty during this volatile period. In the current environment, assumptions about future commodity prices, exchange rates, and interest rates are subject to greater variability than normal, which could in the future significantly affect the valuation of Leucrotta's assets, both financial and non-financial. As an understanding of the longer-term impacts of COVID-19 on commodity, credit and equity markets develops, there is amplified potential for changes in estimates and judgments in the future.

3. SIGNIFICANT ACCOUNTING POLICIES

The condensed interim financial statements have been prepared following the same accounting policies as the annual financial statements for the year ended December 31, 2020. The accounting policies have been applied consistently by the Company to all periods presented in these condensed interim financial statements.

4. PROPERTY, PLANT, AND EQUIPMENT

Cost	Total
Balance, December 31, 2019	245,142
Additions	6,953
Transfer from exploration and evaluation assets (note 5)	3,923
Sale of properties	(5,585)
Sale of equipment	(2,673)
Change in decommissioning obligations	3,242
Capitalized share based compensation	2
Balance, December 31, 2020	251,004
Additions	**12,669**
Sale of property	**(37,433)**
Change in decommissioning obligations	**(552)**
Capitalized share based compensation	**242**
Balance, September 30, 2021	**225,930**

Accumulated Depletion, Depreciation, and Impairment	Total
Balance, December 31, 2019	62,400
Sale of properties	(814)
Sale of equipment	(621)
Depletion and depreciation	9,003
Impairment	98,973
Balance, December 31, 2020	168,941
Sale of property	**(12,937)**
Depletion and depreciation	**4,835**
Impairment reversal	**(66,414)**
Balance, September 30, 2021	**94,425**

Net Book Value	Total
December 31, 2020	82,063
September 30, 2021	**131,505**

During the three and nine months ended September 30, 2021, $0.2 million (September 30, 2020 - $6 thousand) and $0.2 million (September 30, 2020 - $53 thousand), respectively, of directly attributable general and administrative costs were capitalized as expenditures on property, plant, and equipment.

Dispositions

On April 1, 2021, the Company disposed of natural gas assets located in Doe, BC for gross proceeds of $30.0 million (net proceeds of $29.25 million after deducting $750 thousand of transaction costs). The disposed assets were comprised of $29.9 million of non-strategic lands and four wells less liabilities of $0.6 million, detailed as follows:

Book value of net assets disposed	
Cost of property, plant, and equipment	**37,433**
Accumulated depletion, depreciation and impairment of property, plant, and equipment	**(12,937)**
Cost of exploration and evaluation assets (note 5)	**5,364**
Decommissioning obligations (note 8)	**(610)**
	29,250

Consideration	
Cash	**29,250**

During the year ended December 31, 2020, the Company received proceeds of $6.0 million from a third party related to its Two Rivers property and lands. Management determined the net carrying value of these properties was $0.7 million higher than the estimated consideration which resulted in the recognition of an impairment loss applied against the carrying value of these properties. The sale closed on May 5, 2020.

During the year ended December 31, 2020, the Company closed a sale of non-core facility assets for cash consideration of $2.2 million and non-cash consideration of $1.5 million of operating credits. The operating credits will be received in the form of discounted future service costs for use of the purchaser's facilities and expire after 10 years from the date of closing (May 2030). The operating credits have been recognized at their expected fair value of $1.2 million with $0.2 million recorded in Prepaid expenses and deposits and $1.0 million recorded as Deferred credits. During the three and nine months ended September 30, 2021, $27 thousand and $104 thousand (year ended December 31, 2020 - $75 thousand), respectively, of operating credits were recognized. Net assets disposed of consisted of facility assets of $2.1 million and related decommissioning obligations of $0.2 million, resulting in a gain on sale of $1.5 million. There were no reserves assigned to the facility assets disposed of through the transaction.

Depletion and depreciation

The calculation of depletion and depreciation expense as at September 30, 2021 included an estimated $182.0 million (September 30, 2020 - $323.1 million) for future development costs associated with proved plus probable undeveloped reserves and excluded approximately $4.4 million (September 30, 2020 - $4.8 million) for the estimated salvage value of production equipment and facilities.

Included in depletion and depreciation expense for the three and nine months ended September 30, 2021, is $23 thousand (September 30, 2020 - $23 thousand) and $68 thousand (September 30, 2020 - $68 thousand), respectively, related to the right-of-use asset for the Company's head office lease. At September 30, 2021, the net book value of this right-of-use asset is $7 thousand.

Impairment (Reversal) Assessment

At September 30, 2021, the Company evaluated its property, plant, and equipment ("PP&E") Montney CGU for indicators of impairment or impairment reversals. At September 30, 2021, indicators of impairment reversal were determined to exist in the Company's Montney CGU primarily as a result of significant and sustained increase in forward commodity benchmark prices for oil, natural gas and natural gas liquids ("NGLs").

The recoverable amount of the Company's Montney CGU, comprised of primarily natural gas and NGLs reserves, was determined using the value in use methodology based on the net present value of cash flows from oil and natural gas reserves at pre-tax discount rates ranging from 10 to 20 percent depending on the underlying composition and risk profile of the reserve category. At September 30, 2021, the Company determined that the recoverable amount of $117.3 million, net of associated decommissioning obligations, of the Company's Montney CGU exceeded the carrying amount and accordingly, an impairment reversal of $66.4 million was recorded.

Commodity price estimates based on an average of three independent reserve evaluators used in the impairment reversal calculations as at September 30, 2021 were as follows:

Year	West Texas Intermediate Oil ($US/bbl)	Foreign Exchange Rate (USD/CDN)	Edmonton Light, Sweet Oil ($CDN/bbl)	AECO Gas Price ($CDN/mmbtu)	Chicago Gas Price ($USD/mmbtu)
2021	75.17	0.795	89.62	4.57	5.26
2022	71.00	0.798	83.72	3.83	4.11
2023	67.77	0.800	79.06	3.25	3.30
2024	65.57	0.800	76.18	2.99	3.03
2025	66.88	0.800	77.70	3.05	3.09
2026	68.22	0.800	79.25	3.11	3.16
2027	69.58	0.800	80.84	3.18	3.22
2028	70.97	0.800	82.46	3.24	3.29
2029	72.39	0.800	84.10	3.31	3.36
2030	73.84	0.800	85.79	3.37	3.43
2031	75.31	0.800	87.50	3.44	3.50
Escalate Thereafter	2.0% per year		2.0% per year	2.0% per year	2.0% per year

The results of impairment reversal tests are sensitive to changes in any of the key estimates of which changes could decrease or increase the recoverable amounts of assets and result in additional impairment charges or recovery of impairment charges. Key input estimates used in the determination of cash flows from oil and gas reserves include: quantities of reserves and future production, forward commodity pricing, development costs, operating costs, royalty obligations, abandonment costs, and discount rates. As at September 30, 2021, if pre-tax discount rates used in the calculation of impairment changed by 1% with all other variables held constant, the recoverable amount of the Montney CGU would change by approximately $7.4 million. As at September 30, 2021, if commodity price estimates changed by $1.00/bbl for oil and NGLs and $0.10/mcf for natural gas with all other variables held constant, the recoverable amount of the Company's Montney CGU would change by approximately $8.5 million.

At December 31, 2020, the Company evaluated its PP&E Montney CGU for indicators of impairment or impairment reversals. The Company made the decision to reduce its Future Development Capital ("FDC") and long dated developments to better match the Company's go forward development plan. As a result of this re-alignment, indicators of impairment were determined to exist as a result of reducing the reserve bookings and FDC for the Upper Montney at Doe and for the Lower Montney at Two Rivers East where significant drilling and infrastructure capital would be required and is not anticipated at the current time.

The recoverable amount of the Montney CGU was determined using the value in use methodology based on the net present value of cash flows from oil and natural gas reserves at pre-tax discount rates ranging from 10 to 20 percent depending on the underlying composition and risk profile of the reserve category. At December 31, 2020, the Company determined that the carrying amount of the Company's Montney CGU exceeded the recoverable amount, net of associated decommissioning obligations, of $66.8 million and accordingly, an impairment charge of $13.5 million was recorded.

At March 31, 2020, indicators of impairment were determined to exist in the Company's Montney CGU primarily as a result of significant and sustained declines in forward commodity benchmark prices for oil, natural gas and NGLs and a sustained market capitalization deficiency relative to the book value of the Company's shareholders' equity.

The recoverable amount of the Company's Montney CGU was determined using the value in use methodology based on the net present value of cash flows from oil and natural gas reserves at pre-tax discount rates ranging from 10 to 17.5 percent depending on the underlying composition and risk profile of the reserve category. At March 31, 2020, the Company determined that the carrying amount of the Company's Montney CGU exceeded the recoverable amount, net of associated decommissioning obligations, of $86.5 million and accordingly, an impairment charge of $84.8 million was recorded. An additional $2.4 million of impairment was recorded prior to the transfer of certain assets from exploration and evaluation assets to PP&E and an additional $0.7 million of impairment was recorded upon the sale of certain Two Rivers property and lands for a total impairment expense of $87.9 million for the three months ended March 31, 2020.

5. EXPLORATION AND EVALUATION ASSETS

	Total
Balance, December 31, 2019	122,982
Additions	6,763
Transfer to property, plant, and equipment (note 4)	(3,923)
Impairment prior to the transfer to property, plant, and equipment	(2,410)
Sale of properties (note 4)	(1,229)
Land lease expiries	(864)
Capitalized share based compensation	9
Balance, December 31, 2020	121,328
Additions	**5,546**
Sale of property (note 4)	**(5,364)**
Capitalized share based compensation	**20**
Balance, September 30, 2021	**121,530**

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

During the three and nine months ended September 30, 2021, $57 thousand (September 30, 2020 - $nil) and $0.1 million (September 30, 2020 - $0.1 million), respectively, of directly attributable general and administrative costs were capitalized as expenditures on exploration and evaluation assets.

Land lease expiries for the three and nine months ended September 30, 2021 were $nil (September 30, 2020 - $0.5 million) and $nil (September 30, 2020 - $0.9 million), respectively, and have been included in depletion and depreciation expense.

At September 30, 2021, the Company evaluated its exploration and evaluation assets for indicators of impairment or impairment reversals and as a result of this assessment management determined that an impairment test was not required to be performed.

6. LEASE OBLIGATIONS

Lease obligations are discounted with an effective interest rate of 5.0% and right-of-use asset is amortized based on the lease term. The Company's office lease expires October 31, 2021 and has no renewal option in the lease agreement.

	Total
Balance, December 31, 2019	169
Lease payments	(96)
Interest expense	5
Balance, December 31, 2020	78
Lease payments	**(72)**
Interest expense	**2**
Balance, September 30, 2021	**8**
Current	**8**
Long-term	**-**
	8

The total undiscounted amount of the estimated future cash flows to settle the lease obligations over the remaining lease term is $8 thousand. The Company's minimum lease payments are as follows:

	September 30, 2021
Within one year	8
Minimum lease payments	8
Amount representing interest expense	-
Present value of net lease payments	**8**

7. CREDIT FACILITY

During the nine months ended September 30, 2021, the Company entered into a credit agreement with a new lender comprised of a $10.0 million revolving operating demand loan credit facility. The new credit agreement fully replaced the previous $6.0 million credit facility, which was comprised of a $2.0 million demand loan facility and $4.0 million demand letter of credit facility. The revolving credit facility bears interest at prime plus a range of 1.75% to 3.75% and is secured by a floating charge debenture on all the assets of the Company. The undrawn portion of the credit facility is subject to a standby fee in the range of 0.75% to 1.25%. The new 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 lender, 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 definition of current assets and current liabilities excludes unrealized risk management contracts. The Company was compliant with this covenant at September 30, 2021. The next review of the credit facility by the lender is scheduled to occur on or before November 30, 2021.

At September 30, 2021, $nil had been drawn on the credit facility (December 31, 2020 - $5.8 million). At September 30, 2021, the Company had outstanding letters of guarantee of $3.5 million which reduce the amount that can be borrowed under the credit facility.

8. 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 1.67% per year (December 31, 2020 - 1.37%) required to settle the decommissioning obligations is approximately $20.2 million (December 31, 2020 - $19.0 million) which is estimated to be incurred over the next 29 years. At September 30, 2021, a risk-free rate of 1.92% (December 31, 2020 - 1.13%) was used to calculate the net present value of the decommissioning obligations.

	Nine Months Ended September 30, 2021	Year Ended December 31, 2020
Balance, beginning of period	**15,291**	12,191
Provisions incurred	**208**	250
Provisions settled	**(51)**	(144)
Property dispositions (note 4)	**(610)**	(153)
Revisions in estimated cash flows	**346**	1,439
Revisions due to change of rates	**(1,106)**	1,553
Accretion	**171**	155
Balance, end of period	**14,249**	15,291

9. SHAREHOLDERS' CAPITAL AND WARRANTS

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, 2019 and 2020	200,525	288,837
Issue of common shares and flow-through common shares	**47,076**	**29,765**
Issue costs	**-**	**(1,933)**
Flow-through share premium	**-**	**(34)**
Exercise of stock options	**40**	**46**
Balance, September 30, 2021	**247,641**	**316,681**

Warrants	Number	Amount
Balance, December 31, 2019 and 2020	-	-
Issue of warrants	**24,473**	**4,957**
Issue costs	**-**	**(309)**
Balance, September 30, 2021	**24,473**	**4,648**

On March 31, 2021, the Company closed a bought-deal public financing through a syndicate of underwriters. The Company issued 45.2 million units of the Company ("Units") at a price of $0.73 per Unit for gross proceeds of $33.0 million. A Unit is comprised of one common share of the Company and 0.5 common share purchase warrants. Each whole common share purchase warrant entitles the holder to purchase one common share at an exercise price of $1.00 per common share expiring on March 31, 2023.

On June 22, 2021, the Company closed a non-brokered private placement. The Company issued 1.87 million flow-through units of the Company ("Flow-through Units") at a price of $0.73 per Flow-through Unit for gross proceeds of $1.365 million. A Flow-through Unit is comprised of one common share of the Company issued on a flow-through basis in respect of Canadian development expenses ("CDE") under the Income Tax Act (Canada) ("Flow-through Common Share") and 1.0 flow-through CDE common share purchase warrant ("Flow-through Warrant"). Each Flow-through Warrant entitles the holder to purchase one Flow-through Common Share at an exercise price of $1.00 per Flow-through Common Share expiring on June 22, 2024. Upon issuance, the premium received on the flow-through shares, being the difference between the fair value of the flow-through shares issued and the fair value of the common shares at the date of issuance, was recognized as a liability. The Company recorded a one-time share based compensation charge of $0.4 million equal to the difference between the fair value of the Flow-through Units received and the price paid per Flow-through Unit issued to certain officers and directors of the Company. The Company incurred the required CDE of $1.365 million related to the Flow-through Common Shares during the three months ended September 30, 2021. The proceeds of the financing were used to fund the Company's capital program.

As at September 30, 2021, there were 24.5 million warrants outstanding, consisting of 22.6 million common share purchase warrants and 1.87 million Flow-through Warrants.

The fair value of the common share purchase warrants and Flow-through Warrants were estimated on the date of issue using the Black-Scholes-Merton option pricing model with the following weighted average assumptions:

	September 30, 2021
Risk-free interest rate (%)	**0.2**
Expected life (years)	**1.5**
Expected volatility (%)	**91.8**
Expected dividend yield (%)	**-**
Fair value of warrants issued ($ per warrant)	**0.20**

10. SHARE BASED COMPENSATION PLANS

Stock options

The Company has authorized and reserved for issuance 24.8 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. Under the plan, the exercise price of each option equals the market price of the Company's shares on the date of the grant and an option's maximum term is ten years. At September 30, 2021, 18.0 million options were outstanding at an average exercise price of $0.86 per share.

	Number of Options	Weighted Average Exercise Price ($)
Balance, December 31, 2019	11,156	1.25
Granted	7,045	0.60
Expired	(4,395)	1.29
Forfeited	(199)	1.32
Balance, December 31, 2020	13,607	0.90
Granted	**4,830**	**0.77**
Exercised	**(40)**	**0.80**
Expired	**(25)**	**0.93**
Forfeited	**(375)**	**0.81**
Balance, September 30, 2021	**17,997**	**0.86**
Exercisable, September 30, 2021	**8,634**	**1.06**

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 granted to officers, directors, employees, and consultants with a corresponding increase to contributed surplus.

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

	September 30, 2021	December 31, 2020
Risk-free interest rate (%)	**0.8**	0.4
Expected life (years)	**4.0**	4.0
Expected volatility (%)	**64.5**	62.8
Expected dividend yield (%)	**-**	-
Forfeiture rate (%)	**0.6**	0.5
Weighted average fair value of options granted ($ per option)	**0.38**	0.33

During the three and nine months ended September 30, 2021, the Company recognized $0.5 million (September 30, 2020 - $0.2 million) and $1.5 million (September 30, 2020 - $0.3 million), respectively, of share based compensation related to the stock options. At September 30, 2021 there was $2.0 million remaining as unrecognized share based compensation related to the stock options.

11. PER SHARE AMOUNTS

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

	Three Months Ended September 30		**Nine Months Ended September 30**	
	2021	2020	**2021**	2020
Weighted average number of shares - basic	**247,641**	200,525	**231,694**	200,525
Dilutive effect of share based compensation plans	**311**	-	**43**	-
Weighted average number of shares - diluted	**247,952**	200,525	**231,737**	200,525

For the three and nine months ended September 30, 2021, 11.2 million stock options (September 30, 2020 - 18.0 million) and 24.5 million warrants (September 30, 2020 - nil) were anti-dilutive and were not included in the diluted net earnings (loss) per share calculation.

12. FINANCIAL RISK MANAGEMENT

Commodity price risk

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

At September 30, 2021, the Company had the following commodity price contracts outstanding:

Commodity	Period	Type of Contract	Quantity	Contract Price
Oil	October 1, 2021 - December 31, 2021	Financial - Swap	80 bbls/d	WTI CDN $59.60/bbl
Oil	October 1, 2021 - December 31, 2021	Financial - Swap	70 bbls/d	WTI CDN $90.10/bbl
Oil	January 1, 2022 - March 31, 2022	Financial - Swap	150 bbls/d	WTI CDN $88.00/bbl
Natural Gas	October 1, 2021 - December 31, 2021	Financial - Swap	2,900 MMBtu/d	Chicago NGI USD $2.6325/MMBtu
Natural Gas	October 1, 2021 - December 31, 2021	Financial - Swap	2,100 MMBtu/d	Chicago NGI USD $5.0100/MMBtu

For the three and nine months ended September 30, 2021, the realized loss on the risk management contracts was $0.6 million (September 30, 2020 - $nil) and $1.4 million (September 30, 2020 - $nil), respectively, and the unrealized loss was $0.6 million (September 30, 2020 - $nil) and $1.8 million (September 30, 2020 - $nil), respectively.

Financial assets and liabilities are only offset if the Company has the legal right to offset and intends to settle on a net basis or settle the asset and liability simultaneously. The following table summarizes the gross asset and liability positions of the Company's risk management contracts that are offset on the condensed interim statement of financial position:

	September 30, 2021	December 31, 2020
Gross current asset	**-**	198
Gross current liability	**(1,662)**	(51)
Net current (liability) asset	**(1,662)**	147

13. SUPPLEMENTAL CASH FLOW INFORMATION

	Three Months Ended September 30		**Nine Months Ended September 30**	
	2021	2020	**2021**	2020
Restricted cash	**-**	-	**-**	(120)
Accounts receivable	**(940)**	129	**(1,022)**	322
Prepaid expenses and deposits (1)	**(380)**	(163)	**(224)**	73
Accounts payable and accrued liabilities	**4,664**	(141)	**5,620**	(1,345)
Change in non-cash working capital	**3,344**	(175)	**4,374**	(1,070)
Relating to:				
Investing	**4,307**	16	**5,026**	(1,602)
Operating	**(963)**	(191)	**(652)**	532
Change in non-cash working capital	**3,344**	(175)	**4,374**	(1,070)

(1) Prepaid expenses and deposits for the nine months ended September 30, 2021 excludes $0.2 million of non-cash operating credits (see note 4).

14. REVENUE

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

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

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

	Three Months Ended September 30		**Nine Months Ended September 30**	
	2021	2020	**2021**	2020
Oil and condensate	**2,241**	2,253	**7,749**	6,542
Other natural gas liquids	**85**	524	**284**	1,529
Natural gas	**4,628**	3,064	**15,821**	9,000
Oil and natural gas sales	**6,954**	5,841	**23,854**	17,071
Processing income	**156**	178	**683**	312
Total revenue	**7,110**	6,019	**24,537**	17,383

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

	Three Months Ended September 30		Nine Months Ended September 30	
	2021	2020	**2021**	2020
Natural gas production sales	**3,504**	1,700	**11,873**	4,734
Transportation revenue	**1,124**	1,364	**3,948**	4,266
Natural gas sales	**4,628**	3,064	**15,821**	9,000

The Company's revenue was generated entirely in the province of British Columbia. The majority of revenue resulted from sales whereby the transaction price was based on index prices. Of total oil and natural gas sales, three customers represented combined sales of 96% for the nine month period ended September 30, 2021 (September 30, 2020 - three customers represented combined sales of 97%).

During the three and nine months ended September 30, 2021, the Company realized credits of $0.1 million (September 30, 2020 - $0.3 million) and $0.7 million (September 30, 2020 - $0.5 million), respectively, to offset royalties payable. These credits stem from the British Columbia Government's Infrastructure Royalty Credit Program resulting from infrastructure built and wells drilled and tied-into the related infrastructure and has $nil credits remaining.

15. COMMITMENTS

The following is a summary of the Company's contractual obligations and commitments at September 30, 2021:

	2021	**2022**	**2023**	**2024**	**2025**	**Thereafter**	**Total**
Operating commitments	22	47	194	194	194	355	1,006
Firm transportation agreements	1,649	6,641	5,911	2,835	-	-	17,036
	1,671	6,688	6,105	3,029	194	355	18,042

Transportation commitments include contracts to transport natural gas and NGLs through third-party owned pipeline systems. The Company currently has commitments of 13.4 mmcf/d of firm transportation to deliver natural gas to the Alliance Trading Pool (ATP) through October 31, 2023. The Company has also committed to 14.2 mmcf/d of firm transportation to deliver natural gas to Chicago through October 31, 2024.

During the year ended December 31, 2020, the Company entered into an agreement to reduce its firm transportation to deliver natural gas to ATP expiring October 31, 2021 to 13.4 mmcf/d from the previous 33.3 mmcf/d. The cost to reduce the transportation commitment was 50% of the original obligation for a total of $2.1 million payable monthly through October 31, 2021 which was recognized in earnings in Q4 2020 as a loss on onerous contract with an offsetting current liability on the statement of financial position. As at September 30, 2021, $0.2 million remains payable on the onerous contract.

Operating commitments include the non-lease variable components of the head office lease.

During the three months ended September 30, 2021, the Company signed a new head office lease beginning December 1, 2021 to November 30, 2027, with the first year of the lease comprising a rent-free period. Base rent averages $126 thousand per year and operating expenses are anticipated to be approximately $194 thousand per year. The Company will recognize a lease liability and related right-of-use asset on commencement of the lease.

CORPORATE INFORMATION

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FORWARD-LOOKING STATEMENTS

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

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