CLEARVIEW RESOURCES LTD

Clearview Resources Ltd.

Management Discussion and Analysis (MD&A)

December 31, 2019

HIGHLIGHTS FOR THE TWELVE MONTHS ENDED DECEMBER 31, 2019

- Incurred minimal field capital and abandonment expenditures of $0.4 million in the fourth quarter of 2019 to deploy excess adjusted funds flow of $0.9 million towards the reduction of net debt;

- Reduced net debt by $2.8 million in the twelve months ended December 31, 2019, applying the excess of adjusted funds flow over capital and abandonment expenditures of $2.3 million against working capital and bank debt. At December 31, 2019, the Company's net debt to adjusted funds flow ratio was 2.8:1;

- Generated adjusted funds flow of $5.5 million in the twelve months ended December 31, 2019, up 197% from the comparative period, as a result of a 58% increase in total revenue. Cash flow from operations was $5.0 million in the twelve months ended December 31, 2019 versus cash flow from operations of $1.1 million in the comparative nine month period;

- On February 22, 2019, the Company closed the acquisition of producing oil and gas assets and undeveloped land from a private oil and gas producer ("Private Co") for cash consideration of $0.6 million and the issuance to Private Co of 1,361,542 voting common shares of Clearview from treasury;

- Oil production increased 20% to 684 barrels per day ("bbl/d") in the twelve month period ended December 31, 2018, from the comparative nine month period ended December 31, 2018 through successful drilling completed in the prior period and the acquisition of assets completed in the first quarter of 2019;

- Total production increased 9% to 2,425 barrels of oil equivalent per day ("boe/d") in the three months ended December 31, 2019 versus the comparative period and increased 14% to 2,421 boe/d for the twelve months ended December 31, 2019 versus the comparative prior period;

- Realized sales price was $29.08 per barrel of oil equivalent ("boe") for the twelve months ended December 31, 2019 compared to $27.82 per boe in the prior period, an increase of 5%, while the last quarter of 2019 was up 31% to $29.18 per boe from $22.36 per boe in the comparative quarter;

- Total revenue increased by 42% in the three months ended December 31, 2019 versus the comparative period due to higher production volumes for natural gas and natural gas liquids and higher oil and natural gas prices. Total revenue for the twelve months ended December 31, 2019 increased by 58% to $25.7 million due to higher production volumes for all products, higher oil and natural gas prices and an additional three months of production in the current fiscal year; and

- Operating costs per boe increased 1% to $15.93 per boe for the three months ended December 31, 2019, versus the comparative period. For the twelve months ended December 31, 2019, operating costs were $14.88 per boe, down 5% versus the comparative period.

COVID-19

Subsequent to December 31, 2019, the COVID-19 outbreak was declared a pandemic by the World Health Organization. The situation is dynamic with governments (federal, provincial and municipal) worldwide, responding in different ways to combat the spread of the virus. These measures have caused material disruption to businesses, resulting in an economic slowdown, globally. Clearview continues to monitor the impact of the outbreak on its business as there could be meaningful effects, both direct and indirect.

In April of 2020, the Company made the decision to shut-in approximately 50% of its production, primarily its oil production and the natural gas associated with the oil production, due to the significant drop in crude oil prices from an oversupply of oil globally, relative to current demand for oil as a result of the shutdown of economies worldwide to deal with COVID-19. The Company has chosen to preserve the value of its reserves and produce them at a later date when better economic conditions have returned.

Future Operations

Clearview has a demand, reserve-based, revolving credit facility with an Alberta based financial institution which was renewed in October 2019 at a credit facility limit of $18.5 million. The credit facility is secured by a general security agreement providing a security interest over all present and acquired property and a floating charge on all oil and natural gas assets. The Company had $14.8 million outstanding on the credit facility at December 31, 2019 and has $14.0 million outstanding with available cash on hand of $0.6 million as of April 27, 2020.

The next borrowing base redetermination is scheduled to be completed by no later than June 30, 2020. The available lending limits are based on the lender's interpretation of the Company's reserves and future commodity prices. There can be no assurance as to the amount of available credit that will be determined at the next review.

While the Company has an amount outstanding under its credit facility as of April 27, 2020 which is less than the current credit facility limit of $18.5 million, the Company remains dependent on the support of its lender. In addition, the recent significant decline in crude oil prices due to macro-economic uncertainty, an over-supply of oil globally and a significant reduction in demand due to the impact of COVID-19 has caused the Company to shut-in a significant portion of its operated production to preserve the value of its reserves. The shut-in of production and significant decline in crude oil and natural gas liquids prices has the Company projecting a significant reduction in cash flow from operating activities in 2020, increasing the risk of a covenant violation and further increasing the requirement of the Company to have available the entire $18.5 million credit facility limit to support continued operations. If the credit facility is not renewed by the lender, at or above its existing lending limits, is at any time placed on demand, or a covenant violation is not remedied or waived by the lender, the outstanding amount could become payable immediately, and there is no certainty that the Company would have available capital resources to repay the bank debt.

Due to the facts and circumstances detailed above, coupled with considerable economic instability and uncertainty in the oil and gas industry which negatively impact operating cash flows and lender and investor sentiment, there is a material uncertainty surrounding the Company's ability to continue as a going concern that creates significant doubt as to the ability of the Company to meet its obligations as they become due and, therefore, it may be unable to realize its assets and discharge its liabilities in the normal course of business.

Change in Year End

During the previous fiscal year, the Board of Directors approved changing the Company's fiscal year end from March 31 to December 31 to have the Company's year-end financial statements more comparative with the majority of its industry competitors. Consequently, the management discussion and analysis ("MD&A") is a review of the financial position and results of operations of the Company for the three months ended December 31, 2019 as compared to the three months ended December 31, 2018 for quarterly comparisons and the twelve months ended December 31, 2019 as compared to the nine months ended December 31, 2018 for yearly comparisons.

The MD&A should be read in conjunction with the Company's audited financial statements and accompanying notes for the periods ended December 31, 2019 and December 31, 2018. The audited financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. All dollar amounts in the tables are expressed in thousands of Canadian dollars ($000's), except per unit amounts, and unless otherwise noted. The MD&A has been prepared and approved by the Board of Directors as of April 22, 2020.

Refer to page 28 for information about non-GAAP measures, page 29 for information on forward-looking statements and page 30 for measures, conversions and acronyms used in the MD&A.

OVERVIEW OF THE COMPANY

Clearview Resources Ltd. (the "Company") is a privately owned, growth-oriented oil and natural gas producing company based in Calgary, Alberta with production and development primarily focused in the Greater Pembina area of west central Alberta. Additional information about the Company is available on the Canadian Securities Administrators' System for Electronic Distribution and Retrieval ("SEDAR") at www.sedar.com and on the Company's website at www.clearviewres.com.

The Company's oil and natural gas properties are listed below:

Region - Alberta	Property	Primary production	P+P Reserves[1]	Average WI	Operatorship[2]
Greater Pembina	Northville	Liquids rich natural gas	5,758	87%	Yes
	Pembina	Liquids rich natural gas	1,611	80%	Yes
	Wilson Creek	Light oil and liquids rich natural gas	4,587	60%	Yes
	Windfall	Light oil	3,505	100.0%	Yes
	Niton	Light oil	2,826	96%	Yes
	Garrington	Light oil and liquids rich natural gas	1,611	94%	Yes
	Caribou	Light oil	521	63.3%	Yes
Other	Bantry	Medium oil	389	40.0%	No
	Carstairs (Unit)	Liquids rich natural gas	372	17.0%	No
	Lindale (Unit)	Light oil with associated natural gas and liquids	312	10.6%	No
	Crossfield (Unit)	Liquids rich natural gas	36	4.2%	No
	Miscellaneous	Various	55	Various	Mixed
Total			21,583		

[1] mboe of total proved plus probable reserves at December 31, 2019 as determined by the Company's independent reserves evaluator, McDaniel & Associates Consultants Ltd.
[2] operatorship of a majority of the property

The Company's objectives continue to be:

- acquire long life, cash generating oil and natural gas properties with growth potential;
- maintain a low cost and financially robust structure;
- maintain an appropriate debt versus equity capital structure;
- build the Company's production base to fund the field capital program from internally generated funds;
- maintain strong lending values to support the Company's credit facility;
- maintain a current licensee liability rating of 2.0 or greater, providing the Company with the ability to transact on further acquisition opportunities; and
- evaluate non-core assets, for potential disposition, to fund the capital program.

SELECTED ANNUAL INFORMATION

	Three months ended		Periods ended		
	Dec. 31 2019	Dec. 31 2018	Dec. 31 2019	Dec. 31 2018	Mar. 31 2018
Oil and natural gas sales	6,512	4,585	25,687	16,273	20,286
Adjusted funds flow (1)	1,271	511	5,494	1,852	3,679
Per share – basic	0.11	0.05	0.48	0.18	0.44
Per share – diluted	0.11	0.05	0.48	0.18	0.44
Cash flow from operations	1,120	1,312	4,980	1,088	4,337
Per share – basic	0.10	0.13	0.43	0.11	0.51
Per share - diluted	0.10	0.13	0.43	0.11	0.51
Net earnings (loss)	(5,527)	(2,083)	(8,768)	(4,832)	(8,460)
Per share – basic	(0.48)	(0.20)	(0.76)	(0.48)	(1.00)
Per share – diluted	(0.48)	(0.20)	(0.76)	(0.48)	(1.00)
Total assets			80,038	80,752	72,714
Total long term liabilities			23,420	22,645	18,873
Net debt (1)			15,358	18,186	14,154
Total capital expenditures – net (2)	354	3,364	1,955	6,172	6,375

(1) See non-GAAP measures.
(2) Cash additions and acquisitions net of proceeds on dispositions

For the fiscal year ended December 31, 2018, oil and natural gas sales and adjusted funds flow were reduced by there being three fewer months of operations, significantly lower oil prices in the last quarter of the year and reduced natural gas prices. The net loss was impacted by these factors in addition to a loss on the disposition of property for $0.7 million and an impairment in the fiscal year ended March 31, 2018 of $1.4 million. Long term liabilities increased due to the acquisition of Bashaw Oil Corp. through increased decommissioning obligations.

In the twelve months ended December 31, 2019, the Company's oil and natural gas sales increased to $25.7 million due to higher production from the acquisition of producing properties in the first quarter and increased total oil production for the Company from the new wells drilled in 2018. Adjusted funds flow was $5.5 million while cash flow from operations was $5.0 million for the twelve months ended December 31, 2019. Long term liabilities increased in the twelve months ended December 31, 2019 in connection with an acquisition of assets in the first quarter of 2019 and a decrease in interest rates negatively affecting the discounting of decommissioning obligations. Net debt was reduced over the twelve months ended December 31, 2019 as adjusted funds flow in excess of capital expenditures was applied against working capital and bank debt.

Acquisitions and dispositions

(a) Acquisition of Private Co. properties

On February 22, 2019, Clearview acquired producing oil and gas assets and undeveloped land from a private oil and gas producer ("Private Co") for cash consideration of $0.6 million and the issuance to Private Co of 1,361,542 voting common shares of Clearview issued from treasury. The operations of the acquired assets have been included in Clearview's results commencing on February 22, 2019.

The total consideration paid by Clearview was approximately $9.1 million based on a share price for Clearview of $6.25 per share. Transaction costs of $0.1 million were recorded in earnings.

The acquisition of assets from Private Co has been accounted for as a business combination. The net assets have been allocated as follows:

Acquisition Date	February 22, 2019
Consideration	
Cash consideration	581
Share consideration (1,361,542 common shares)	8,509
Total consideration	9,090
Net assets at estimated fair value	
Working capital	87
Exploration and evaluation assets	182
Property, plant and equipment	10,764
Deferred income tax liabilities	(1,108)
Decommissioning obligations	(835)
Net assets	9,090

(b) Acquisition of Bashaw Oil Corp.

On April 16, 2018, Clearview acquired all of the issued and outstanding common shares of Bashaw Oil Corp. ("Bashaw") through a share for share exchange with the issuance of 1,560,046 voting common shares of the Company. The operations of Bashaw have been included in Clearview's results commencing on April 16, 2018. Bashaw Oil Corp. was subsequently amalgamated into Clearview Resources Ltd.

The total consideration paid by Clearview was approximately $8.2 million based on a share price, agreed upon by the two parties, for Clearview of $5.28 per share, which was determined to be fair value at closing. Transaction costs of $16 thousand were recorded in earnings.

The acquisition of Bashaw has been accounted for as a business combination. The net assets have been allocated as follows:

Acquisition Date	April 16, 2018
Consideration	
Share consideration (1,560,046 common shares)	8,237
Net assets at estimated fair value	
Working capital (including cash of $1,671)	1,710
Property, plant and equipment	7,725
Decommissioning obligations	(1,198)
Net assets	8,237

(c) Acquisition of assets

During the twelve months ended December 31, 2019, the Company acquired working interests of joint venture partners in its Central Alberta Gas CGU for cash consideration of $16 thousand (nine months ended December 31, 2018 - $67 thousand).

(d) Disposition of assets

Current fiscal period

During the twelve months ended December 31, 2019, the Company closed the disposition of a non-operated minor working interest in a natural gas property in its Central Alberta Gas CGU and the disposition of a royalty interest in 1,257 natural gas wells. Proceeds from the dispositions were $29 thousand, after closing adjustments, resulting in a gain on dispositions of $25 thousand, recorded in earnings. The dispositions included the reduction of $4 thousand in decommissioning obligations.

Prior fiscal period

On April 10, 2018, the Company closed the disposition, to a related entity controlled by a director of the Company, for proceeds of $3.4 million, after closing adjustments. The proceeds from the disposition were immediately applied to reduce the Company's bank debt. No gain or loss was recorded on this disposition at closing.

On December 10, 2018, the Company sold non-core properties in the Southern Alberta Oil CGU for net proceeds of $126 thousand. The acquirer assumed the decommissioning obligations associated with the properties. The Company recorded a loss on the disposition of the properties of $0.7 million as calculated below:

	December 20, 2018
Cost	1,343
Accumulated depletion	(270)
Net book value	1,073
Decommissioning obligations assumed by the acquirer	(239)
Net carrying amount	834
Proceeds on the dispositions	(126)
Loss on disposition	708

Capital expenditures and drilling activity

	Three months ended			Periods ended		
	Dec. 31 2019	Dec.31 2018	% Change	Dec. 31 2019	Dec. 31 2018	% Change
Land	7	2	250%	7	33	(79)
Drilling, completions, equipping	303	3,902	(92)	931	9,422	(90)
Facilities	99	(388)	126	535	142	277
Other	(55)	(24)	129	1	3	(67)
Capital invested	354	3,492	(90)	1,474	9,600	(85)
Disposition of properties	-	(128)	(100)	(29)	(3,495)	(99)
Net capital invested	354	3,364	(89)	1,445	6,105	(76)
Acquisition of properties	-	-	-	510	67	661
Total capital expenditures	354	3,364	(89)	1,955	6,172	(68)

The Company spent less than one-half of its adjusted funds flow on capital expenditures in the twelve months ended December 31, 2019 with the largest single component of the expenditures being the cash component of the acquisition of assets as discussed earlier. Other significant capital expenditures included workovers in several fields, replacement and upgrading of a generator and compressor and the overhaul of its facility in the Windfall area.

Production

Production is summarized in the following table:

	Three months ended			Periods ended		
	Dec. 31 2019	Dec. 31 2018	% Change	Dec. 31 2019	Dec. 31 2018	% Change
Oil – bbl/d	621	668	(7)	684	568	20
Natural gas liquids – bbl/d	494	437	13	481	445	8
Total liquids – bbl/d	1,115	1,105	1	1,165	1,013	15
Natural gas – mcf/d	7,859	6,745	17	7,537	6,682	13
Total – boe/d	2,425	2,229	9	2,421	2,127	14

Production for the quarter ended and period ended December 31, 2019 increased by 9% and 14% over the respective comparative periods due to the acquisition of properties from a private company in the first three months of the current fiscal year. With a focus on acquiring and drilling light oil opportunities, oil production increased 20% for the twelve months ended December 31, 2019. Oil production decreased 7% over the comparative quarter due to the normal decline of two horizontal oil wells drilled in the second half of the prior fiscal year. Natural gas liquids, generally associated with natural gas production, increased 13% and 8% for the quarter ended and period ended December 31, 2019 versus the comparative periods. The increase was primarily due to the acquisition of properties in the first quarter of the current fiscal year. Natural gas production increased by 17% and 13% for the quarter and period ended December 31, 2019 as a result of production realized as solution gas with the two new light oil wells brought on stream in the prior fiscal year and natural gas production acquired in the first quarter of 2019.

Production, on a boe/d basis, from the Company's core properties was as follows:

	Three months ended			Periods ended		
	Dec. 31 2019	Dec. 31 2018	% Change	Dec. 31 2019	Dec. 31 2018	% Change
Wilson Creek	453	585	(23)	461	463	-
Northville	707	879	(20)	717	757	(5)
Pembina	224	201	11	230	213	8
Caribou	139	158	(12)	149	157	(5)
Garrington	182	-	100	145	-	100
Windfall	334	276	21	357	228	57
Total – boe/d	2,039	2,099	(3)	2,059	1,818	13
% of total production	84%	94%	(11)	85%	85%	-

Clearview's production portfolio for the quarter ended December 31, 2019 was weighted 26% to oil, 20% to natural gas liquids and 54% to natural gas. For the period ended December 31, 2019 the production mix was weighted 28% to oil, 20% to natural gas liquids and 52% to natural gas. The majority of the natural gas produced by the Company is either associated with light oil production or has significant natural gas liquids in the natural gas production stream. The Company has very little dry natural gas production (approximately 300 mcf/d or 50 boe/d) which is at risk of being shut-in during periods of low natural gas prices.

Benchmark prices and economic parameters

	Three months ended			Periods ended		
	Dec. 31 2019	Dec. 31 2018	% Change	Dec. 31 2019	Dec. 31 2018	% Change
Oil – West Texas Intermediate ("WTI") (US $/bbl)	56.96	58.82	(3)	57.03	65.38	(13)
Oil – Edmonton Par ($/bbl)	68.07	42.68	59	69.22	68.41	1
Differential – Light oil ($/bbl) (1)	7.11	34.94	(80)	6.44	16.94	(62)
NGLs - Pentane ($/bbl)	74.95	64.45	16	71.39	78.98	(10)
NGLs – Butane ($/bbl)	40.93	13.51	203	23.71	28.74	(18)
NGLs – Propane ($/bbl)	26.88	24.13	11	17.16	24.99	(31)
Natural gas – AECO ($/mcf)	2.47	1.56	58	1.76	1.31	34
Exchange rate – US$/Cdn$	0.756	0.756	-	0.754	0.765	(1)

(1) The light oil differential is calculated as WTI in Canadian dollars minus the Edmonton Par price.

The refiners' posted prices for Canadian crude oils are influenced by the WTI reference price, transportation capacity and costs, US$/Cdn$ exchange rates and the supply/demand situation of particular crude oil quality streams during the period. Benchmark oil prices in 2019 were reasonably steady throughout the current period between US $50.00 and $60.00 per barrel but still represented a 13% decrease from the comparative period. Canadian oil prices remained very consistent with the prior period with only a 1% increase on average as lower benchmark pricing was offset by a lower US/Cdn exchange rate and a narrowing light oil differential. Canadian oil prices for the three months ended December 31, 2019 were Cdn $68.07 per barrel, an increase of 59% as compared to the same quarter of the prior year as a result of the light oil differential narrowing back to Cdn $7.11 per barrel from $34.94 per barrel in the comparative period.

Pentane prices averaged $71.39 per barrel for the period ended December 31, 2019, a decrease of about 10 percent from the previous year. The decrease in pentane prices is consistent with the decrease in WTI for the year of 13% and a slightly decreasing US$/Cdn$ exchange rate. For the three months ended December 31, 2019, pentane prices were $74.95 per barrel, 16% higher than the comparative period of the prior year, due to a more normal supply and demand situation than in the three months ended December 31, 2018.

Butane prices averaged $23.71 per barrel for the period ended December 31, 2019, a decrease of 18% from the previous year. Butane prices declined continuously through the period ended December 31, 2018 and into 2019 due to an oversupply of butane in Canada associated with the growth in liquids rich natural gas production in western Canada. Butane prices for the three months ended December 31, 2019 were $40.93 per barrel, an increase of 203% as compared to the same period of the prior year. The significant increase by the end of 2019 was a result of a more balanced demand and supply.

Propane prices averaged $17.16 per barrel for the year ended December 31, 2019, a decrease of about 31 percent from the previous year. Propane prices were lower due to an oversupply of propane at the end of 2018. For the three months ended December 31, 2019, propane prices were $26.88 per barrel, 11% higher than the comparative period of the prior year as supply and demand became more balanced.

Natural gas prices strengthened considerably on average throughout the current period but were still subject to the volatility of much higher prices in the winter months associated with colder weather and high heating demand and the lows in the summer months due to an inability to put excess natural gas production into storage. AECO natural gas prices averaged $1.76 per mcf for the period ended December 31, 2019, an increase of 34% as compared to the prior year. For the three months ended December 31, 2019, AECO natural gas price averaged $2.47 per mcf, a 58% increase over the comparative period as a result of strong winter demand and a change in protocol providing the ability to put excess natural gas production into storage effective October 1, 2019.

Realized sales prices

	Three months ended			Periods ended		
	Dec. 31 2019	Dec. 31 2018	% Change	Dec. 31 2019	Dec. 31 2018	% Change
Oil – $/bbl	64.03	36.20	77	64.69	58.87	10
NGLs – $/bbl	23.87	31.14	(23)	25.69	36.26	(29)
Natural gas – $/mcf	2.44	1.79	36	1.83	1.44	27
Total – $/boe	29.18	22.36	31	29.08	27.82	5

Realized prices primarily vary from the benchmark prices due to quality differences including differences for density and sulphur content. The differential can vary considerably from quarter to quarter. During the three months ended December 31, 2019, the Company's realized oil price was higher by 77% than the comparative quarter as a result of a significant narrowing in light oil price differentials. For the period ended December 31, 2019, realized oil prices were higher by 10% as lower benchmark pricing was offset by a reduced light oil differential and a weaker US/Cdn foreign exchange rate.

Natural gas liquids prices were lower by 23% in the last quarter of the current year as compared to the same quarter of the prior year and 29% lower for the current fiscal year than the previous period. These decreases were primarily due to lower prices received for the Company's propane and butane production pursuant to contract marketing terms with midstream operators due to an oversupply of both propane and butane earlier in the current fiscal year.

The Company's realized price for natural gas was higher by 37% for the three months ended December 31, 2019. This compares to a 58% increase in the benchmark AECO price over the same period. For the period ended December 31, 2019, the Company's natural gas price was higher by 27% versus the increase in AECO of 34% over the year. The increase in realized sales price for the quarter and current period ended December 31, 2019 was less than the increase in benchmark pricing for AECO. The reason for the realized natural gas prices not being similar to the change in AECO is due to the higher price than AECO received in the comparative period. The Company's Windfall natural gas production is very liquids rich and is subject to a heating value and differential adjustment correlated to the Alliance Transfer Point ("ATP") natural gas price. In the current year, the Company received a lower price adjustment on this production than last year resulting in a lower increase in the realized sales price this year relative to AECO. Windfall's natural gas production represented 14% and 13% of the Company's production for the three months and period ended December 31, 2019, respectively.

On a boe basis, the Company's realized price was 31% higher for the three months ended December 31, 2019 than the comparative period, due to higher oil and natural gas prices, and higher by 5% for the period ended December 31, 2019 for the same reasons.

Revenues

Oil and natural gas sales

	Three months ended			Periods ended		
	Dec. 31 2019	Dec. 31 2018	% Change	Dec. 31 2019	Dec. 31 2018	% Change
Oil	3,661	2,223	65	16,152	9,198	76
Natural gas liquids	1,085	1,253	(13)	4,503	4,438	1
Total liquids	4,746	3,476	37	20,655	13,636	51
Natural gas	1,766	1,109	59	5,032	2,637	91
Total sales	6,512	4,585	42	25,687	16,273	58
Per boe	29.18	22.36	31	29.08	27.82	5

Crude oil sales increased 65% in the three months ended December 31, 2019 as a decrease in oil production volumes of 7% was more than offset by a 77% increase in realized oil prices.

Natural gas liquids revenues were lower by 13% in the quarter ended December 31, 2019 as production increases of 13% were more than offset by lower realized natural gas liquids prices by 23%.

Natural gas revenue increased 59% in the quarter ended December 31, 2109 as higher production volumes of 17% were sold for a 37% higher realized natural gas price than in the comparative quarter.

The 58% increase in oil and gas sales for the period ended December 31, 2019 is primarily due to three months more of operations in the current year but also production per day was 14% higher than the previous year and the realized sales price per boe was 5% higher than the previous year.

Revenues from the sale of oil, natural gas and natural gas liquids are normally collected on the 25th day of the month following production. Clearview received over 96% of its monthly production revenue from its customers on this day throughout the year. The remaining 4% is collected within 30 days after the 25th day and represents joint operations, whereby the operator sells the production on Clearview's behalf and subsequently pays Clearview for its working interest share of the revenues.

Processing income

Clearview has a working interest in natural gas processing and compression facilities at its Caroline, Carstairs, Crossfield, Wilson Creek and Northville properties. The Company earns revenue from processing fees on third party production volumes utilizing these facilities, a fee for service arrangement.

	Three months ended			Periods ended		
	Dec. 31 2019	Dec. 31 2018	% Change	Dec. 31 2019	Dec. 31 2018	% Change
Processing income	195	102	91	694	465	49
Per boe	0.87	0.50	74	0.79	0.80	(1)

Processing income increased to $195 thousand for the three months ended December 31, 2019, a 91% increase from the comparative quarter ended December 31, 2018. The increase includes an adjustment of $19 thousand related to a prior year from a non-operated property. The increase in processing income for the year primarily reflects three months more of operations.

Risk management activities

Clearview enters into financial and physical commodity contracts as part of its risk management program to manage commodity price fluctuations, thereby protecting a portion of the revenues received from the sale of its production to its customers.

With respect to financial contracts, which are derivative financial instruments, management has elected not to use hedge accounting. Rather, the Company records the fair value of its natural gas and crude oil financial contracts on the statement of financial position at each reporting period with the change in the fair value being classified as an unrealized gain or loss in earnings.

The Company had the following financial and physical commodity price contracts outstanding at December 31, 2019.

Commencement Date	Expiry Date	Units	Volume	Underlying Commodity	Fixed Price
November 1, 2019	March 31, 2020	GJ/day	1,000	AECO 5A - Financial	$2.20
January 1, 2020	December 31, 2020	GJ/day	1,000	AECO 5A – Financial	$1.57
January 1, 2020	December 31, 2020	GJ/day	1,000	AECO 5A – Physical	$1.61
January 1, 2020	December 31, 2020	GJ/day	1,000	AECO 5A - Financial	$1.89
January 1, 2020	March 31, 2020	Bbls/day	125	US WTI - Financial	$58.05
January 1, 2021	December 31, 2021	Bbls/day	150	US WTI – Call option	$65.00 **

** The Company sold a call option for 2021 on 150 barrels per day at US $65.00 per barrel and transferred the value for selling the call into the financial hedge for US $58.05 per barrel.

The fair value of the financial contracts outstanding as at December 31, 2019 is estimated to be a liability of $0.2 million. At December 31, 2018 the fair value of the financial contracts outstanding was an asset of $64 thousand. The fair value of these contracts is based on the forward prices and market values provided by independent sources and represents the asset that would have been received from the counterparties to settle the contracts at the end of the reporting period. Due to the volatility of commodity prices, interest rates and foreign exchange rates, actual amounts may differ from these estimates.

For the period ended December 31, 2019, the Company recognized an unrealized loss of $0.3 million on its outstanding commodity contracts versus an unrealized gain of $1.2 million in the prior year ended December 31, 2018. In the three months ended December 31, 2019, Clearview recorded an unrealized loss on commodity contracts of $0.3 million as compared to an unrealized gain of $0.8 million in the three months ended December 31, 2018. The unrealized loss in the three months and fiscal year ended December 31, 2019 is the difference between the fair values of the commodity contracts at December 31, 2019 and the fair values of outstanding commodity contracts at the respective prior reporting periods.

For the year ended December 31, 2019, the Company had a realized gain on commodity contracts of $49 thousand versus a realized loss in the prior year of $0.8 million. During the three months ended December 31, 2019, the Company recorded a realized loss of $78 thousand versus a realized gain of $0.4 million in the comparative quarter.

The Company has executed additional commodity price contracts for its oil and natural gas production, interest rate swaps and foreign exchange rate swaps subsequent to December 31, 2019 as follows:

Commencement Date	Expiry Date	Units	Volume	Underlying Commodity	Fixed Price
January 1, 2020	June 30, 2020	Bbls/day	200	US WTI - Financial	$60.55
April 1, 2020	October 31, 2020	GJ/day	1,000	AECO 5A – Physical	$1.61
April 1, 2020	October 31, 2020	GJ/day	1,000	AECO 5A - Financial	$1.75
April 1, 2021	October 31, 2021	GJ/day	2,000	AECO 5A - Financial	$1.86
January 1, 2021	December 31, 2021	GJ/day	1,000	AECO 5A - Financial	$2.10

Commencement Date	Expiry Date	Notional Amount	Underlying Commodity	Fixed Rate
April 1, 2020	March 31, 2021	$3,000,000	CDOR - Financial	1.41%
April 1, 2020	March 31, 2021	$3,000,000	CDOR - Financial	1.20%

Commencement Date	Expiry Date	Notional Amount	Underlying Commodity	Fixed Rate
April 1, 2020	June 30, 2020	US $160,000	US/Cdn - Financial	1.3795
July 1, 2020	December 31, 2020	US $200,000	US/Cdn - Financial	1.435

Management monitors the forward price market for oil and natural gas, on an ongoing basis, and may contract additional production volumes as attractive pricing opportunities become available or if production increases from development or acquisitions.

Royalties

	Three months ended			Periods ended		
Amount	Dec. 31 2019	Dec. 31 2018	% Change	Dec. 31 2019	Dec. 31 2018	% Change
Crown – oil	272	217	25	1,184	1,088	9
Crown – natural gas liquids	294	421	(30)	1,170	1,378	(15)
Crown – natural gas	73	57	28	257	141	82
Gas cost allowance	(327)	(594)	(45)	(1,426)	(1,528)	(7)
Total Crown	312	101	209	1,185	1,079	10
Freehold	194	86	126	796	391	104
Gross over-riding	132	165	(20)	827	514	61
Total royalties	638	352	81	2,808	1,984	42
Per boe	2.86	1.72	66	3.18	3.39	(6)

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

The Company reviews its entitlement to gas cost allowance at each reporting period. The timeframe for the royalty regulatory process, the complexity of the calculation and the uncertainty (particularly for non-operated properties from which the Company takes its revenue in kind) as to whether the

Company will be eligible to actually receive the allowance are factors considered in determining the estimate and the amount to record for that period.

Royalty rate	Three months ended Dec. 31 2019	Dec. 31 2018	% Change	Periods ended Dec. 31 2019	Dec. 31 2018	% Change
Total Crown	4.8%	2.2%	118	4.6%	6.6%	(30)
Freehold	3.0%	1.9%	58	3.1%	2.4%	29
Gross over-riding	2.0%	3.6%	(44)	3.2%	3.2%	-
Total royalties	9.8%	7.7%	27	10.9%	12.2%	(11)

The overall royalty burden for the fiscal year decreased by 11% to a rate of 10.9% versus 12.2% for the prior year. Crown royalty rates were lower due to lower natural gas and natural gas liquids prices which were offset by gas cost allowance and lower oil royalty rates due to oil production from the two new horizontal wells drilled in the previous year having a maximum royalty rate of 5% during the entire year. Freehold royalties increased due to a prior period adjustment of $60 thousand and higher realized prices on production.

The increase in royalty rate for the three months ended December 31, 2019 of 27% is primarily due to significantly higher realized prices for oil and natural gas than in the comparative quarter. The increase in freehold royalties and decrease in gross over-riding royalties in the three months ended December 31, 2019 is primarily due to the reclassification of the above prior period adjustment of $60 thousand between the freehold and gross over-riding categories.

Transportation expenses

	Three months ended Dec. 31 2019	Dec. 31 2018	% Change	Periods ended Dec. 31 2019	Dec. 31 2018	% Change
Transportation costs	342	291	18	1,428	769	86
Per boe	1.53	1.42	8	1.62	1.32	23

Transportation expenses include trucking costs for delivery of the Company's oil production and third-party pipeline tariffs to deliver natural gas production to the purchasers at the main market hubs. The Company had 77% of its natural gas volumes under firm service transportation contracts with NGTL and operators of midstream facilities that process the Company's natural gas production. Transportation expense increased 18% in the three months ended December 31, 2019 due to higher natural gas production volumes and higher costs of trucking oil production due to winter conditions over the same three months versus the comparative period.

For the period ended December 31, 2019, transportation costs were higher by 86%. The increase is a combination of 20% more oil volumes being trucked per day, higher natural gas production volumes and three months more of transportation costs than the previous year.

Operating expenses

	Three months ended Dec. 31 2019	Dec. 31 2018	% Change	Periods ended Dec. 31 2019	Dec. 31 2018	% Change
Operating costs	3,555	3,247	9	13,146	9,177	43
Per boe	15.93	15.83	1	14.88	15.69	(5)

The Company continues to focus on reducing production costs given the volatility of oil and natural gas prices. However, components of operating an oil and natural gas property are essentially fixed, e.g. property taxes, lease rentals and insurance.

Operating costs for the three months ended December 31, 2019 were $15.93 per boe, higher by 1%, than the comparative quarter of the prior year, at $15.83 per boe. For the twelve month period ended December 31, 2019, operating costs decreased 5% on a per boe basis versus the comparative fiscal year. This decrease primarily reflects an increase in production per day of 14% resulting in the spreading of fixed costs over a larger production base.

General and administrative expenses

	Three months ended			Periods ended		
	Dec. 31 2019	Dec. 31 2018	% Change	Dec. 31 2019	Dec. 31 2018	% Change
Gross costs	594	548	8	2,534	1,775	43
Overhead recoveries	(67)	(100)	(33)	(246)	(305)	(19)
Total G&A expenses	527	448	18	2,288	1,470	56
Per boe	2.36	2.18	8	2.59	2.51	3

General and administrative costs, net of recoveries, increased 18% in the three months ended December 31, 2019 versus the comparative period as increased costs were offset by fewer overhead recoveries due to lower capital expenditures in the current fiscal year.

For the period ended December 31, 2019, general and administrative costs, net of recoveries, increased 56% due to the current year reflecting three months more of costs. On a per boe basis, for the current fiscal year, general and administrative costs increased 3% over the prior fiscal year.

Stock based compensation

Stock based compensation is the amortization over the vesting period of the fair value of stock options. The Company has granted options to acquire voting common shares to directors, officers, employees and consultants to provide an incentive and retention component of the compensation plan. The Board of Directors of the Company set the terms of the options at the time of grant. The fair value of all options granted is estimated at the time of the grant using the Black-Scholes option pricing model.

The first round of options granted in June and August 2016 expire 7 years from the date of grant and vest one third immediately and one third on each of the first and second anniversaries. Subsequent grants also expire 7 years from the date of grant but vest one third on each of the first, second and third anniversaries. During the current period, no options were granted by the Company. In the prior period, the Company granted options to acquire 463,500 voting common shares with an exercise price of $5.00 per share under option, with expiration and vesting as described above. The assumptions used in determining the fair values were as follows:

Period ended	December 31, 2018
Exercise price	$5.00
Volatility	73%
Expected option life	6.7 years
Dividend	$nil
Risk-free interest rate	2.25%

The Company is not listed on a stock exchange. The exercise prices were based on recent issue prices for the voting common shares. The estimate of volatility is based on the volatility of the entire sector of oil and gas producers on a Canadian stock exchange.

	Three months ended			Periods ended		
	Dec. 31 2019	Dec. 31 2018	% Change	Dec. 31 2019	Dec. 31 2018	% Change
Stock based compensation	145	362	(60)	834	695	20
Per boe	0.65	1.77	(63)	0.94	1.19	(21)

Stock based compensation expense for the three months ended December 31, 2019 was lower by 60% versus the comparative period. The decrease in expense is primarily due to lower monthly expense, a year later, for options granted to a director and numerous employees in the second quarter of the prior fiscal year. For the period ended December 31, 2019, the expense was higher by 20% due to more amortization as a result of there being one more quarter in the year ended December 31, 2019 versus the prior period.

Depletion, depreciation and impairment

	Three months ended			Periods ended		
	Dec. 31 2019	Dec. 31 2018	% Change	Dec. 31 2019	Dec. 31 2018	% Change
Depletion	2,440	2,257	8	10,034	6,159	63
Depreciation	1	2	(50)	7	6	17
Impairment	3,750	-	100	3,750	-	100
Total	6,191	2,259	174	13,791	6,165	124
Per boe – depletion	10.93	11.00	(1)	11.36	10.53	8
Per boe - depreciation	0.01	0.01	-	0.01	0.01	-
Per boe - impairment	16.80	-	100	4.24	-	100
Total	27.74	11.01	152	15.61	10.54	48

The Company calculates depletion on property, plant and equipment using the unit-of-production method based on proved plus probable reserves. Depreciation is calculated based on the useful lives of office equipment and furniture. The increase in depletion for the three months ended December 31, 2019 is primarily due to greater production volumes. Production increased 9% versus an increase in the depletion expense of 8%. Depletion for the period ended December 31, 2019 was 63% higher than the prior year. This increase reflects the fact that there is one more quarter of production in the period ended December 31, 2019 versus the prior period.

At December 31, 2019, Clearview identified indicators of impairment, primarily due to the volatility of Canadian natural gas prices, forecast commodity prices having declined from the previous year, primarily natural gas and the Company's change in development plans for the Southern Alberta Oil CGU. Clearview performed an impairment test on its Central Alberta Gas and Southern Alberta Oil CGU's at December 31, 2019 based on fair value less cost to sell to calculate the estimated recoverable amount of each CGU. The estimated recoverable amount was based on before-tax discount rates specific to the underlying reserve category and risk profile of each CGU, net of decommissioning obligations. The discount rates used in the valuation ranged from 15 to 25 percent. The impairment test indicated the Company's Central Alberta Gas CGU's recoverable amount was less than its carrying value resulting in an impairment of $3.75 million charged to earnings.

The following table details the forward pricing used in estimating the recoverable amount of each CGU at December 31, 2019.

	WTI	Edmonton Light	Bow River Medium	Propane	Butane	Pentane	AECO Spot
Year	US/bbl	Cdn/bbl	Cdn/bbl	Cdn/bbl	Cdn/bbl	Cdn/bbl	Cdn/bbl
2020	61.00	72.64	58.43	26.36	42.10	76.83	2.04
2021	63.75	76.06	63.00	29.80	47.03	79.82	2.32
2022	66.18	78.35	64.99	32.94	50.66	82.30	2.62
2023	67.91	80.71	66.91	34.00	52.21	84.72	2.71
2024	69.48	82.64	68.65	34.88	53.48	86.71	2.81
2025	71.07	84.60	70.41	35.78	54.77	88.73	2.89
2026	72.68	86.57	72.20	36.69	56.07	90.77	2.96
2027	74.24	88.49	73.91	37.57	57.32	92.76	3.03
2028	75.73	90.31	75.53	38.41	58.50	94.65	3.09
2029	77.24	92.17	77.18	39.26	59.71	96.57	3.16
2030	78.79	94.01	78.72	40.04	60.90	98.50	3.23
2031	80.36	95.89	80.29	40.85	62.12	100.47	3.29
2032	81.97	97.81	81.90	41.66	63.36	102.48	3.36
2033	83.61	99.76	83.54	42.50	64.63	104.53	3.43
2034	85.28	101.76	85.21	43.35	65.92	106.62	3.49
2035+	+2.0%/yr	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.

Transaction costs

	Three months ended			Periods ended		
	Dec. 31 2019	Dec. 31 2018	% Change	Dec. 31 2019	Dec. 31 2018	% Change
Transaction costs	7	-	100	118	16	638
Per boe	0.03	-	100	0.13	0.03	333

Transactions costs for the period ended December 31, 2019 were higher by 638% as compared to the prior period. The increase in transaction costs was primarily due to the transaction costs associated with the acquisition of assets from a private company which closed on February 22, 2019.

Finance costs

	Three months ended			Periods ended		
	Dec. 31 2019	Dec. 31 2018	% Change	Dec. 31 2019	Dec. 31 2018	% Change
Interest on bank debt	264	258	2	1,074	688	56
Credit facility fees and costs	25	23	9	76	26	192
Cash finance costs	289	281	3	1,150	714	61
Accretion expense (1)	170	57	198	457	328	39
Total finance costs	459	338	36	1,607	1,042	54
Per boe – cash finance costs	1.29	1.37	(6)	1.30	1.22	7
Per boe – accretion expense	0.76	0.28	171	0.52	0.56	(7)

(1) Accretion is a non-cash finance cost associated with the Company's decommissioning obligation.

Cash finance costs include interest on bank debt and lender fees plus minor amounts for miscellaneous interest and penalties charged by vendors and taxing authorities. Interest on bank debt in the three months ended December 31, 2019 increased by only 2%. The minimal increase was due to the stability of the bank prime lending rate during the year and outstanding bank debt being reduced by adjusted funds flow in excess of capital expenditures. These factors were offset by a slightly higher credit spread pursuant to the Company's lending agreement.

The interest rate on prime based borrowings under the credit facility has increased over the past two years were as follows:

- January 2018 - from 6.20% to 6.45% - increase in the prime rate,

- July 2018 – from 6.45% to 6.70% - increase in prime rate, and
- October 2018 – from 6.70% to 6.95% - increase in prime rate.

The average rate for prime based borrowings during the period ended December 31, 2019 was 6.95%.

The Company also has the option of borrowing using the lender's guaranteed notes which are subject to a current stamping fee of 4.0% per annum plus the guaranteed note rate for 30, 60, 90 and 180 day terms. Guaranteed notes resulted in an average rate of approximately 5.97% during the period ended December 31, 2019.

In addition, the Company pays its lender a standby fee of 1.20% on the difference between the credit facility of $18.5 million and the combined prime rate borrowings and guaranteed notes borrowings.

The accretion of decommissioning obligations relates to the passing of time until the Company estimates it will retire its assets and restore the asset locations to a condition which at a minimum meets environmental standards. This accretion expense is estimated to extend over a term of the next 43 years due to the long-term nature of certain assets. Accretion expense increased in the three months ended December 31, 2019 due to additional obligations acquired in the acquisition of properties in the first quarter of the current fiscal year. The increase in accretion expense for the period end December 31, 2019 as compared to the prior year is a result of the current year representing accretion expense for twelve months versus nine months in the prior period and additional obligations associated with the acquisition of assets in the first quarter of the current fiscal year.

Income taxes

	Three months ended			Periods ended		
	Dec. 31 2019	Dec. 31 2018	% Change	Dec. 31 2019	Dec. 31 2018	% Change
Deferred income tax recovery	-	5	(100)	1,108	76	1,358
Per boe	-	0.03	(100)	1.25	0.13	862

The Company has concluded that it is not probable that the deferred income tax asset associated with temporary timing differences will be realized. As a result, it has not been recognized on the statement of financial position at December 31, 2019. Therefore, no deferred income tax expense or recovery has been recorded in earnings in the current period. The deferred tax recovery of $1.1 million for the period ended December 31, 2019 represents the recognition of a portion of the Company's deferred income tax asset to offset the deferred income tax liability created on the acquisition of properties in the first quarter of the year.

Clearview has no current income taxes payable and has estimated tax pools available against income of $150.5 million, including non-capital tax loss carry-forwards of $62.5 million which will expire over the years 2024 to 2038. The successor pools were acquired as part of oil and gas property acquisitions in March 31, 2017 and the acquisition of Bashaw Oil Corp. on April 16, 2018. The pools can be deducted to the extent of future profits attributable to the acquired properties. During the taxation years ended March 31, 2017 to December 31, 2019, Clearview has claimed $11.3 million against the successor pools.

The Company's tax pools as at December 31, 2019 are set out below:

Nature of tax pool	%[1]	Regular	Successor[2]	Total
Canadian exploration expense (CEE)	100	170	14,257	14,427
Canadian development expense (CDE)	30	7,031	14,944	21,975
Canadian oil and gas property expense (COGPE)	10	30,348	8,048	38,396
Foreign resource expenses	10	4,951	-	4,951
Undepreciated capital cost (UCC)	25	8,119	-	8,119
Share issue costs	20	92	-	92
Non-capital losses carry forward	100	62,528	-	62,528
Total tax pools		113,239	37,249	150,488

[1] The percentage rate shown is the maximum rate of deduction.
[2] The pools can be claimed to the extent of future profits attributable to the acquired properties related to the pools.

Adjusted funds flow

The following is a reconciliation of cash flow provided by (used in) operating activities to adjusted funds flow:

	Three months ended			Year ended		
	Dec. 31 2019	Dec. 31 2018	% Change	Dec. 31 2019	Dec. 31 2018	% Change
Cash flow provided by (used in) operating activities	1,120	1,312	(15)	4,980	1,088	358
Add back (deduct)						
Decommissioning expenditures	60	59	2	289	59	390
Change in non-cash working capital	91	(860)	111	225	705	(68)
Adjusted funds flow (1)	1,271	511	148	5,494	1,852	197

(1) See non-GAAP measures

Adjusted funds flow increased 148% for the three months ended December 31, 2019, primarily due to higher revenues from higher production volumes and realized prices, particularly oil and natural gas prices, which was partially offset by realized losses on commodity contracts.

For the period ended December 31, 2019, cash flow from operations was $5.0 million compared to $1.1 million for the year ended December 31, 2018. The decrease of 357% was primarily due to higher revenues from higher prices and realized gains on commodity contracts and one more quarter of operations.

For the period ended December 31, 2019 adjusted funds flow was $5.5 million compared to $1.9 million for the period ended December 31, 2018. The increase of 197% was due to higher revenues from higher production and prices for oil and natural gas and one quarter more of operations.

Net loss

	Three months ended			Periods ended		
	Dec. 31 2019	Dec. 31 2018	% Change	Dec. 31 2019	Dec. 31 2018	% Change
Net earnings (loss)	(5,527)	(2,083)	165	(8,768)	(4,832)	81
Per boe	(24.76)	(10.14)	144	(9.92)	(8.26)	20
Per share – basic	(0.48)	(0.20)	135	(0.76)	(0.48)	58
Per share – diluted	(0.48)	(0.20)	135	(0.76)	(0.48)	58

The Company sustained net losses of $5.5 million and $8.8 million for the three months and period ended December 31, 2019, respectively, compared to net losses of $2.1 million and $4.8 million for the comparative periods, respectively.

The increase in the net loss for the period ended December 31, 2019 was primarily due to an impairment expense of $3.75 million related to the Company's Central Alberta Gas CGU.

Netback analysis

	Three months ended			Periods ended		
Barrel of oil equivalent ($/boe)	Dec. 31 2019	Dec. 31 2018	% Positive (Negative)	Dec. 31 2019	Dec. 31 2018	% Positive (Negative)
Realized sales price	29.18	22.36	31	29.08	27.82	5
Royalties	(2.86)	(1.72)	(66)	(3.18)	(3.39)	6
Processing income	0.87	0.50	74	0.79	0.80	(1)
Transportation	(1.53)	(1.42)	(8)	(1.62)	(1.32)	(23)
Operating	(15.93)	(15.83)	(1)	(14.88)	(15.69)	5
Operating netback (2)	9.73	3.89	150	10.19	8.22	24
Realized gain (loss) – commodity contracts	(0.35)	2.16	(116)	0.06	(1.29)	105
General and administrative	(2.36)	(2.18)	(8)	(2.59)	(2.51)	(3)
Transaction costs	(0.03)	-	(100)	(0.13)	(0.03)	(333)
Cash finance costs	(1.29)	(1.37)	6	(1.30)	(1.22)	(7)
Corporate netback (2)	5.70	2.50	128	6.23	3.17	97
Unrealized gain (loss) – commodity contracts	(1.31)	4.13	132	(0.33)	2.04	(116)
Stock based compensation	(0.65)	(1.77)	63	(0.94)	(1.19)	21
Depletion and depreciation	(10.94)	(11.01)	1	(11.37)	(10.54)	(8)
Impairment	(16.80)	-	(100)	(4.24)	-	(100)
E&E Expense	-	(0.29)	100	(0.03)	(0.10)	70
Accretion	(0.76)	(0.28)	(171)	(0.52)	(0.56)	7
Gain (loss) on dispositions	-	(3.45)	100	0.03	(1.21)	102
Deferred income taxes	-	0.03	100	1.25	0.13	862
Net earnings (loss)	(24.76)	(10.14)	(144)	(9.92)	(8.26)	(20)

(1) % Positive (Negative) is expressed as being positive (better performance in the category) or negative (reduced performance in the category) in relation to operating netback, corporate netback and net earnings.

(2) See Non-GAAP measures

The Company's corporate netback for the year ended December 31, 2018 increased 97% to $6.23 per boe compared to the prior period. The increase is primarily due to higher realized sales price for the Company's production of $29.08 per boe in the current period versus $27.82 per boe in the prior period and realized gains on commodity contracts of $0.06 per boe in the current period versus realized losses on commodity contracts of $1.29 in the prior period.

SUMMARY OF QUARTERLY RESULTS

Three months ended	Dec 31 2019	Sep 30 2019	Jun 30 2019	Mar 31 2019	Dec 31 2018	Sep 30 2018	Jun 30 2018	Mar 31 2018
Production								
Oil (bbl/d)	621	641	709	768	668	581	455	498
Natural gas liquids (bbl/d)	494	501	452	473	437	437	462	450
Natural gas (mcf/d)	7,859	7,487	7,153	7,646	6,745	6,537	6,764	7,175
Total (boe/d)	2,425	2,389	2,353	2,515	2,229	2,107	2,044	2,144
Financial								
Oil and natural gas sales	6,512	5,357	6,318	7,500	4,585	6,297	5,391	5,794
Adjusted funds flow (1)	1,271	879	1,280	2,064	511	749	592	429
Per share – basic	0.11	0.08	0.11	0.19	0.05	0.07	0.06	0.05
Per share – diluted	0.11	0.08	0.11	0.19	0.05	0.07	0.06	0.05
Net earnings (loss)	(5,527)	(2,129)	(658)	(454)	(2,083)	(1,000)	(1,749)	(3,879)
Per share – basic	(0.48)	(0.18)	(0.06)	(0.04)	(0.20)	(0.10)	(0.18)	(0.46)
Per share - diluted	(0.48)	(0.18)	(0.06)	(0.04)	(0.20)	(0.10)	(0.18)	(0.46)

(1) See non-GAAP measures.

Production remained relatively flat on a quarter over quarter basis in the twelve months ended December 31, 2019 as a result of the acquisition in the first quarter of the year and proactive and successful field operations to minimize downtime. Oil and natural gas sales and adjusted funds flow increased significantly in the first quarter of the current fiscal period due to higher oil production from the two new wells drilled in the previous fiscal period, improved benchmark pricing for oil and higher natural gas pricing through the winter. Throughout the remainder of the current period, adjusted funds flow varied with the price of natural gas production and much lower prices for propane and butane due to new marketing contract provisions with industry midstream companies. The increased loss in the last quarter of the current period was primarily due to an impairment expense of $3.75 million related to the Company's Central Alberta Gas CGU.

LIQUIDITY AND CAPITAL RESOURCES

The Company's liquidity was strengthened during the current fiscal year as net debt was reduced by $2.8 million as adjusted funds flow in excess of capital expenditures was used to repay outstanding bank debt and reduce the Company's accounts payables. As a result, net debt is $15.4 million at December 31, 2019, down from $18.2 million at December 31, 2018, with the components set out below:

As at	Dec. 31, 2019	Dec. 31, 2018
Trade and other receivables	2,940	2,358
Prepaid expenses and deposits	606	648
Bank debt	(14,807)	(16,553)
Accounts payable and accrued liabilities	(3,675)	(4,639)
Decommissioning obligations	(422)	-
Net debt (1)	(15,358)	(18,186)

(1) See Non-GAAP measures.

Balance sheet strength and flexibility remain a priority through an even more challenging environment with the recent drop in world crude oil prices. The Company continues to proactively consider funding alternatives, including a further equity raise and/or non-core asset sales, building on the steps taken in prior years. Improved liquidity is a priority as the Company continues to evaluate strategic acquisitions during the current historic low acquisition and disposition market and prepares for the next review of its credit facility, to be completed by no later than June 30, 2020. The Company monitors net debt as a key component of managing liquidity risk and determining capital resources available to finance future development.

At December 31, 2019, the Company had a demand revolving operating facility with ATB Financial with a limit of $18.5 million (December 31, 2018 - $21.0 million) of which $14.8 million (December 31, 2018 - $16.6 million) was drawn. The interest rate is prime plus 3% and the loan agreement requires monthly interest payments only.

The next scheduled review of the credit facility is no later than June 30, 2020. As the available lending limits are based on the lender's interpretation of the Company's reserves and future commodity prices, there can be no assurance as to the amount of available credit that will be determined at each scheduled review. The Company's credit facility is also a demand loan and as such the lender could demand repayment at any time. Since the facility is a demand loan it is classified as a current liability. Management is not aware of any indications the lender would demand repayment. The Company is current with all interest and fee payments and is compliant with all financial covenants, particularly the working capital covenant. The Company's ratio as per the working capital covenant is 1.8 to 1, well in excess of the minimum requirement of 1:1. In addition, the Company and its lender have agreed to a covenant whereby the Company's shall maintain a liability management rating ("LMR") of no less than 2.0. Clearview's LMR as at December 31, 2019 was 2.7.

The Company manages liquidity risk, the risk that the Company will not be able to meet its financial obligations as they become due, by monitoring cash flows from operating activities, reviewing actual capital expenditures against budget, managing maturity profiles of financial assets and liabilities and having an active commodity price risk management program.

Subsequent to December 31, 2019, the COVID-19 outbreak was declared a pandemic by the World Health Organization. The situation is dynamic with governments (federal, provincial and municipal) worldwide, responding in different ways to combat the spread of the virus. These measures have caused material disruption to businesses, resulting in an economic slowdown, globally. Clearview continues to monitor the impact of the outbreak on its business as there could be meaningful effects, both direct and indirect.

CONTRACTUAL OBLIGATIONS

The Company is committed to future minimum payments for natural gas transmission and office space. The Company has a lease for office space which expires June 29, 2020 and acquired an additional office lease as part of the acquisition of Bashaw which expires April 30, 2020. The Company recovers a portion of the office costs from subleases to other corporations. These amounts are not reflected as recoveries in the table below.

The following is a summary of the Company's future minimum contractual obligations and commitments as of December 31, 2019.

	2020	2021	2022	2023	Thereafter
Bank debt	14,807	-	-	-	-
Accounts payable and accrued liabilities	3,675	-	-	-	-
Decommissioning obligations	422	422	422	422	22,154
Gas transportation	242	94	4	-	-
Office lease	134	-	-	-	-
Total	19,280	516	426	422	22,154

OFF-BALANCE SHEET ARRANGEMENTS

The Company has not engaged in any off-balance sheet arrangements. The commodity contracts for natural gas prices disclosed in the MD&A and are recorded at fair value as "fair value – commodity contracts" on the statements of financial position at each reporting period with gains and losses recognized in earnings.

OUTSTANDING SHARE DATA

The Company is authorized to issue an unlimited number of voting common shares, an unlimited number of non-voting common shares and an unlimited number of preferred shares, issuable in series. As of April 22, 2020, the Company has 11,671,387 voting common shares outstanding and 1,061,167 options to acquire voting common shares outstanding. All outstanding options have a 7-year life from the date of grant and vest as follows, based on respective exercise prices of $4.50 and $5.00.

Vesting period	Options - $4.50	Options - $5.00	Total
Currently vested	344,500	324,168	668,668
Vesting in the future in the three months ending:			
June 30, 2020	-	81,000	81,000
September 30, 2020	-	154,500	154,500
December 31, 2020	-	2,500	2,500
September 30, 2021	-	154,499	154,499
Total	344,500	716,667	1,061,167

For further details about the options refer to Note 9 to the financial statements as at and for the period ended December 31, 2019.

RELATED PARTY TRANSACTIONS

There were no related party transactions in the twelve months ended December 31, 2019.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Company's audited financial statements requires management to adopt accounting policies that involve the use of significant estimates and assumptions. These estimates and assumptions are developed based on the best available information and are believed by management to be reasonable under the existing circumstances. New events or additional information may result in the revision to these estimates over time.

Management is often required to make judgments, assumptions and estimates in the application of International Financial Reporting Standards that may have a significant impact on the financial results of the Company. The Company's significant accounting policies are described in Note 3 to the audited financial statements for the periods ended December 31, 2019 and December 31, 2018. Certain estimates and judgments are described in Note 2 to the audited financial statements for the periods ended December 31, 2019 and December 31, 2018. The following is a discussion of the accounting estimates that are critical in determining the Company's financial results.

Property, plant and equipment

Oil and natural gas reserves - The Company's proved and probable oil and natural gas reserves at the current and prior year end were evaluated and reported on by the Company's independent qualified reserves evaluator. The estimation of reserves is a subjective process. Forecasts are based on geological and engineering data, projected future rates of production, estimated commodity price forecasts and the timing of future expenditures, all of which are subject to a number of uncertainties and interpretations. The Company expects that over time its reserve estimates will be revised upward or downward based on updated information such as the results of future drilling, testing and production levels. Proved and probable reserve estimates can have a significant impact on net earnings, as they are a key component in the calculation of depletion on a unit of production basis. Significant changes to commodity price forecasts and/or reserve estimates could also result in impairment or an impairment recovery.

Depletion - The unit-of-production method of depletion is based on estimated proven and probable reserves. Changes in estimated proved and probable reserves or future development costs have a direct impact on depletion expense.

Impairment - The impairment test uses forecast prices determined by the Company's independent reserve evaluator adjusted for price differentials specific to the Company and considered reasonable and relevant to the Company's products. The Company is also exposed to variability in operating and capital cost estimates and discount rates.

Decommissioning obligations

Decommissioning obligations are estimated for all wells and facilities in which the Company has an interest, regardless of whether reserves have been attributed to those assets by the Company's independent reserves evaluator. The Company estimates the future retirement date and likely current abandonment and reclamation costs for each well and facility based on current regulatory requirements, the regulator's estimates of such costs used to determine abandonment and reclamation costs and the Company's own experience, including historical costs incurred for abandonment or reclamation. To estimate future retirement costs, the Company applied a 1.33% inflation factor to its estimate of current costs. The Company believes this inflation factor is reasonable over the long term and is consistent with rates used by others in the industry. The risk-free rate is used to discount decommissioning provisions to the current reporting date. Expected retirement dates are based on the productive life of the wells as determined by the independent qualified reserves evaluator and by regulatory requirements. In estimating the fair value of decommissioning obligations which are a component of a business combination, the Company uses a market discount rate, which has varied between 10% and 13% over the past two years.

Stock based compensation

The Company's accounting policy for stock based compensation was applied to account for the options granted during the periods ended December 31, 2019 and December 31, 2018. The costs of stock based compensation are calculated by reference to the fair value of the options at the date on which they are granted, using the Black-Scholes option pricing model. The Company is not listed on any stock exchange so judgment is required to determine the exercise price and to estimate volatility for purposes of the Black-Scholes option pricing model. The exercise price has been the same price at which the Company issued voting common shares near the date of the option grant. If options are issued in the future and there have not been recent issues of the voting common shares to third parties, judgment will be necessary to estimate a fair value for the exercise price. The estimate of volatility is based on oil and natural gas producers listed on a Canadian stock exchange.

Deferred tax assets

At each reporting period the Company evaluates deferred income tax assets to make a determination of whether the assets are likely to be realized. Based on management's assessment that it is not probable that future taxable income will be available against which the temporary differences will be utilized, all deferred tax assets previously recognized were expensed in 2015 and 2016. If the Company were to record deferred income tax assets in the future or at such time as it is required to record a net deferred income tax liability, it will be required to determine substantially enacted income tax rates applicable to the future years. The Company estimates the accounting and tax values during the period over which temporary difference are likely to reverse and tax rates expected to be effective when the temporary differences reverse.

Financial instruments

The estimated fair values of derivative financial instruments resulting in financial assets and liabilities, by their very nature, require estimates. The Company ensures the price received for a portion of its oil and natural gas volumes through the use of financial derivatives and estimates the mark to market value at each reporting period by applying estimated forward prices to the contracted volumes.

Cash-generating units ("CGU")

The determination of which assets constitute a cash generating unit requires management to make judgments as to the assets to be grouped together. A cash-generating unit is defined to be the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets. Because impairment testing is performed at the level of the cash-generating unit, rather than for individual assets, the composition of a CGU is an important judgement that may significantly impact the determination of recoverable amounts and the resulting impairment. The key estimates used in the determination of future cash flows from oil and natural gas assets include the following:

Reserves – The Company utilizes the reserves prepared by the Company's independent qualitied reserves evaluator. Assumptions that are valid at the time of the reserve estimation may change significantly when new information becomes available. Changes in forecast prices, production levels or results of future drilling may change the economic status of reserves and may result in reserves being revised.

Oil and natural gas prices – The Company utilizes the forecast prices provided by the Company's independent qualitied reserves evaluator. Commodity prices can fluctuate significantly within short periods of time for a variety of reasons including supply and demand fundamentals, access to facilities and pipelines, inventory levels, exchange rates, weather, and economic and geopolitical factors.

Operating costs, future development costs and estimates and timing of future decommissioning obligations – Estimates of future costs are used in the cash flow model, based on an analysis of actual costs incurred in recent years and then escalated for assumed future inflation. Actual results in the future may vary considerably from these estimates.

Discount rate – The Company estimates a range of discount rates for each of the six different categories of reserves (three categories for each of proved and probable reserves, being producing, developed but not producing and undeveloped). The estimated ranges of discount rates are those likely to be applied by an independent market participant and consideration of comparable asset transactions. Changes in the general economic environment could result in significant and rapid changes to discount rates being applied in the marketplace.

The determination of assets constituting a cash-generating unit requires judgment as to the assets to be grouped together into the smallest group of assets that generates cash inflows from continuing use that are largely independent of the cash inflows of other assets or groups of assets.

NEW ACCOUNTING POLICIES

New accounting standards:

During the year ended December 31, 2019, the Company adopted the following new accounting standard.

Leases

Effective January 1, 2019, the Company adopted IFRS 16 which replaced IAS 17 "*Leases*" and IFRIC 4 "*Determining Whether an Arrangement Contains a Lease*". IFRS 16 introduces a single, on-balance sheet accounting model for lessees which requires the recognition of a right of use asset and a lease liability on the balance sheet for most leases. Certain short-term leases (less than 12 months) and leases of low-value assets can be exempt from the balance sheet recognition requirements and will continue to be expensed through earnings on a straight-line basis over the term of the contract.

The Company adopted IFRS 16 using the modified retrospective approach. Under this method of adoption, the right of use assets recognized were measured at amounts equal to the present value of the lease obligations. The modified retrospective approach does not require restatement of prior period financial information as it recognizes the cumulative effective of IFRS 16 as an adjustment to opening retained earnings and applies the standard prospectively. Clearview elected to not apply lease accounting to certain leases for which the lease term ends within 12 months or is of low value as of the date of adoption.

The Company did an evaluation of all its contracts and it was determined there is no material affect as a result of adopting IFRS 16 and as such no adjustment or additional disclosures have been made.

New accounting standards not yet adopted:

In October 2018, the IASB issued amendments to IFRS 3, “Business Combinations”, to clarify whether a transaction results in an asset acquisition or a business acquisition. The amendments apply to businesses acquired in annual reporting periods beginning after January 1, 2020. Earlier application is permitted. The amendments include an election to use a concentration test. This is a simplified assessment that results in an asset acquisition if substantially all of the fair value of the gross assets are concentrated in a single identifiable asset or a group of similar identifiable assets. If the concentration test is not applied, or the concentration test fails, then the assessment focuses on the existence of a substantive process. Clearview will adopt this standard in the first quarter of 2020.

INDUSTRY CONDITIONS AND RISKS

The business of exploration, development, and acquisition of oil and gas reserves involves financial, operational and regulatory risks inherent in the oil and gas industry, several of which are beyond control of the Company, which may impact the Company's results.

The Company's revenues, profitability, future growth and the carrying value of its properties are substantially dependent on prevailing prices of oil and natural gas. The Company's ability to borrow and to obtain additional capital on attractive terms is also substantially dependent upon oil and gas prices. Prices for oil and gas are subject to volatility in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Company.

While the Board of Directors has the overall responsibility for the establishment and oversight of the Company’s risk management framework, management has the responsibility to administer and monitor these risks. Refer to Note 13 of the audited financial statements for the year ended December 31, 2019 for additional analysis of these risks.

The Company’s activities expose it to a variety of financial risks that arise from its exploration, development, production, and financing activities such as credit risk, liquidity risk and market risk. Presented below is information about the Company’s exposure to each of the above risks, the Company’s objectives, policies and processes for measuring and managing risk, and the Company’s management of capital. Further quantitative disclosures are included throughout this MD&A and in the Company’s audited financial statements. The Company employs risk management strategies and polices to ensure that any exposure to risk complies with the Company’s business objectives and risk tolerance levels. The Company manages commodity price risks by focusing its acquisition program on areas that will generate attractive rates of return even at substantially lower commodity prices than those prices being received at the time of the acquisition. The Company uses derivative financial instruments to manage commodity price risk as described elsewhere in this MD&A.

The Company manages its working capital, net debt and the ratio of net debt to adjusted funds flow so as not to overextend the Company. Capital expenditures are limited to cash provided by operating activities, available lines of credit and proceeds from issuing shares when the Company believes that it is prudent.

Operational risks include exploration and development of economic oil and gas reserves, unsuccessful exploration and development drilling activity, competition from other producers, reservoir performance, safety and environmental concerns, access to and ability to retain cost effective contract services, escalating industry costs for contracted services and equipment, product marketing and hiring and retaining qualified employees.

The Company attempts to control operating risks by:

- maintaining a disciplined approach to implementation of the exploration and development program,
- monitoring operations and maintaining close communications with operators and joint interest partners,
- maintaining insurance commensurate with its level and scope of operations to protect against loss from destruction of assets, pollution, blowouts, or other losses.

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial, and local laws 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. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil, or water may give rise to liabilities to governments and third parties and may require the Company to incur costs to remedy such discharge.

Although the Company believes that it is compliant with current applicable environmental regulations, no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development, or exploration activities or otherwise adversely affect the Company's financial condition, results of operations or prospects.

The Company's operations are subject to risks normal in the operation and development of oil and natural gas properties and the drilling of oil and natural gas wells, including encountering unexpected formations or pressures, blowouts and fires, all of which could result in personal injuries, loss of life and damage to property of the Company and others. In accordance with customary industry practice, the Company is not fully insured against all these risks, nor are all such risks insurable, however management believes that adequate insurance has been obtained, where available. Environmental regulation is becoming increasingly stringent and costs and expenses of regulatory compliance are increasing. The Company expects it will be able to fully comply with all regulatory requirements in this regard.

The Company is subject to a variety of regulatory risks that it does not control. Safety and environmental matters are monitored to ensure compliance and to ensure employees, contractors and the public are protected. Changes in government or regulatory policies for matters such as royalties, income taxes, surface rights, mineral rights, operational requirements or processes for regulatory approvals, may impact the Company’s operations, financial results and real or perceived risk to investors or creditors. These matters are largely beyond the Company’s control but are monitored and managed to the extent possible.

Non-GAAP measures

The Company's management uses and reports certain measures not prescribed by International Financial Reporting Standards ("IFRS") (referred to as "non-GAAP measures") in the evaluation of operating and financial performance.

Operating netback is a non-GAAP measure used by the Company to assess its operating results. The Canadian Oil and Gas Evaluation Handbook ("COGEH") describes netback as "an operations indicator to assess operating priorities and evaluate smaller capital expenditures normally associated with field maintenance and improvement". The COGEH provides guidance that "the netback calculation takes the price received for a unit of production at a point in time and deducts from it all production costs, royalties and production taxes to find the cash netback to the producer from each barrel of oil or mcf of sales gas". The Company computes the operating netback for the Company directly from the applicable amounts on the Statements of Operations in the financial statements being oil and natural gas sales and processing income less royalties, production and transportation costs. This amount divided by the associated production volume (usually in boe's) provides a per unit amount.

Adjusted funds flow is a non-GAAP measure derived from cash flow from operating activities excluding decommissioning expenditures and changes in non-cash working capital. The adjusted funds flow amount represents funds available for capital expenditures and abandonment, repayment of net debt or distribution to shareholders.

Corporate netback is the adjusted funds flow amount divided by the total production for the period and represents the cash margin received on each barrel of oil equivalent sold.

Net debt consists of current assets (excluding financial derivatives) less current liabilities (excluding financial derivatives). Net debt is used to assess financial strength, capacity to finance future development and manage liquidity risk.

Operating netback, adjusted funds flow, corporate netback and net debt do not have any standardized meanings prescribed by IFRS and therefore may not be comparable with the calculation of a similar measure for other companies. The Company uses these terms as an indicator of financial performance because such terms are used internally in managing and governing the Company and are often utilized by investors and other financial statement users to evaluate producers in the oil and natural gas industry.

Forward-looking statements

The matters discussed in the MD&A include certain forward-looking statements. Forward-looking statements include, without limitation, any statement that may predict, forecast, indicate, or imply future results, performance, or achievements. Forward-looking statements may be identified, without limitation, by the use of such words as “anticipates”, “estimates”, “expects”, “intends”, “plans”, “predicts”, “projects”, “believes”, or words or phrases of similar meaning. In addition, any statement that may be made concerning future performance, strategies or prospects and possible future corporate action, is also a forward-looking statement. Forward-looking statements are based on current expectations and projections about future general economic, political and relevant market factors, such as interest rates, foreign exchange rates, equity and capital markets, and the general business environment, in each case assuming no changes to applicable tax or other laws or government regulation. Expectations and projections about future events are inherently subject to, among other things, risks and uncertainties, some of which may be unforeseeable. Accordingly, assumptions concerning future economic and other factors may prove to be incorrect at a future date. Forward-looking statements are not guarantees of future performance, and actual events could differ materially from those expressed or implied in any forward-looking statements made by the Company. Any number of important factors could contribute to these digressions, including, but not limited to, general economic, political and market factors in North America and internationally, interest and foreign exchange rates, global equity and capital markets, business competition, technological change, changes in government relations, unexpected judicial or regulatory proceedings and catastrophic events. The Company stresses that the above-mentioned list of important factors is not exhaustive. The Company urges all readers to consider these and other factors carefully before making any investment decisions. The Company urges all readers to avoid placing undue reliance on forward-looking statements. The Company disclaims any intention or obligation to update or revise these forward-looking statements as a result of new information, future events or otherwise, except as required under applicable securities laws.

Measures, conversions and acronyms

In this document, the abbreviations set forth below have the following meanings:

bbl	Barrel	mcf	Thousand cubic feet
mbbl	Thousand barrels	mmcf	Million cubic feet
bbl/d	Barrels per day	mcf/d	Thousand cubic feet per day
NGLs	Natural gas liquids	mmbtu	Million British Thermal Units
boe	Barrels of oil equivalent	gj	Gigajoule
boe/d	Barrels of oil equivalent per day	mboe	Thousand boe

Boe - Barrels of oil equivalent is determined on the basis of 1 boe to 6 mcf of natural gas and boe's may be misleading, particularly if used in isolation. A boe conversion ratio of 1 boe for 6 mcf is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

WTI - West Texas Intermediate is the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade**.**
AECO – AECO is a natural gas storage facility located at Suffield, Alberta and the price of natural gas at this terminal is used as a benchmark for Canadian purposes.
API - an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil.

The following table sets forth certain conversions between Standard Imperial Units and the International System of Units (or metric units).

To convert from	To	Multiply by
mcf	1,000 m^3 of gas	0.028
1,000 m^3 of gas	Mcf	35.493
Bbl	m^3 of oil	0.158
m^3 of oil	bbl	6.290
Feet	Meters	0.305
Meters	Feet	3.281
Miles	Kilometers	1.609
Kilometers	Miles	0.621
Acres	Hectares	0.405
Hectares	Acres	2.471
mcf	gj	0.95

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