CLEARVIEW RESOURCES LTD

Clearview Resources Ltd.

Management Discussion and Analysis (MD&A)

September 30, 2020

COVID-19 and Economic Uncertainty

In March 2020, the COVID-19 outbreak was declared a pandemic by the World Health Organization. In addition, global commodity prices have declined significantly due to a collapse in demand attributed to COVID-19 in combination with an oversupply of oil. Governments worldwide, including those in Canada, have enacted emergency measures to combat the spread of the virus. These measures, which include the implementation of travel bans, self-imposed quarantine periods and physical distancing, have caused material disruption to businesses globally, resulting in an economic slowdown. Governments and central banks have reacted with significant monetary and fiscal interventions designed to stabilize economic conditions, however, the success of these interventions is not currently determinable. The current economic
environment may have significant adverse impacts on the Company including, but not limited to:

• Material declines in revenue and cash flows as a result of the decline in commodity prices;
• Declines in revenue and cash flows due to a reduced capital program and shut-in production;
• Increased impairment charges (see Note 6);
• Inability to comply with restrictions in lending agreements;
• Increased risk of non-performance by the Company's customers which could materially increase the risk of nonpayment of accounts receivable and customer defaults; and
• If the situation continues for a further prolonged period of time it could jeopardize the Company's ability to continue as a going concern.

The situation is dynamic and the ultimate duration and magnitude of the impact on the economy and the financial effect on the Company is not known at this time. Estimates and judgments made by management in the preparation of these financial statements are increasingly difficult and subject to a higher degree of measurement uncertainty during this volatile period.

At current forward pricing scenarios, crude oil and natural gas production companies in Canada may not conform to the standard reserve-based lending ("RBL") structures with their lenders. The Federal Government has acknowledged the challenges facing the oil and gas industry and has announced support programs intended to provide a liquidity backstop to RBL credit facilities which will be administered through Export Development Canada ("EDC") and the Business Development Bank of Canada ("BDC"). EDC and BDC will work directly with the primary banking institutions to provide additional lending and credit capacity to qualifying oil and gas producers that (based on certain criteria) were deemed financially viable prior to the onset of the COVID-19 pandemic. The Company believes it meets the criteria for support under these announced programs and has been working with its lender to access these programs.

At September 30, 2020, Clearview has a demand, reserve-based, revolving credit facility, with an Alberta based financial institution, which has 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 available lending limit is 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 time of each review. The Company had $13.4 million outstanding on the credit facility at September 30, 2020.

While the Company has an amount outstanding under its credit facility which is less than the 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 the Company projecting a significant reduction in cash flow from operating activities in 2020. Recent improvements in realized sales prices and the forward price curves have improved the Company's ability to generate cash flow from 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.

Subsequent events

Over the past several months, the Company has been focused on the completion of three financing initiatives to improve the Company's financial position during these unprecedented times and for the future. These strategic initiatives include:

- Securing a workable credit agreement with its lender that provides the credit capacity and flexibility required for the current economic environment;
- Securing long-term funding through the Federal Government sponsored Export Development Canada Guarantee program; and
- Raising $1.25 million in convertible debentures from the Company's very supportive shareholders to reduce the Company's outstanding bank debt.

Subsequent to the end of the third quarter, Clearview's lender completed its annual review of the Company's revolving, reserve-based credit facility. The credit facility limit was reduced to $15.0 million with the next annual review date being set for October 31, 2021. The Company had $13.5 million outstanding as of November 26, 2020. Borrowings under the credit facility continue to be subject to an interest rate of lender prime, currently at 2.45%, plus a credit spread or at the option of Clearview, using the lender's guaranteed notes, which are subject to the Canadian Dollar Offered Rate ("CDOR"), currently at 0.49% for a 30 day note, plus a stamping fee. The credit spread and stamping fees applicable to the borrowings are based on a pricing margin grid and will change as a result of the ratio of outstanding indebtedness to annualized quarterly funds flows as calculated in accordance with the agreement governing the credit facility. Under this credit agreement, the prime lending credit spread and guaranteed notes stamping fees have increased by 2.75% across the entire pricing grid.

The reserve-based credit agreement continues to require compliance with a working capital covenant whereby the Company must maintain a minimum working capital ratio of 1 to 1 and a liability management rating ("LMR") covenant of no less than 2.0. In addition, the Company will now be required to maintain commodity swap contracts for 50% (approximately 3,400 GJ per day) of its natural gas production volumes and 300 barrels per day of its oil production volumes through to the next annual review date.

Simultaneously, the Company obtained an additional credit facility under its existing credit facility agreement with its lender for $6.25 million under the Business Credit Availability Program ("BCAP"), supported by the Export Development Canada ("EDC") Guarantee. The facility has a term of five years with the EDC providing a guarantee to the Company's lender for 80% of the principal amount outstanding. Monthly payments required under the facility are for interest costs only, which are subject to an interest rate of lender prime plus a credit spread, similar to the reserve-based credit facility. The principal amount outstanding must be repaid no later than 50% at the end of the fourth year with the balance of the principal outstanding due for repayment at the end of the fifth year. The Company will be required to pay an upfront fee of 1.8% annually to the EDC.

Additionally, on December 1, 2020, the Company completed a convertible debenture offering to its existing shareholders for $1.25 million. The debentures are unsecured and subordinate to all senior debt of the Company. The interest payable on the debentures is 10%, payable on a quarterly basis, with a term of five years. During the term, the debenture is convertible into common shares of the Company at the option of the holder based on a conversion price of $1.50 per common share. The convertible debentures may be redeemed by the Company, upon consent from its lender, pursuant to the following provisions:

Year 1 – No redemption
Year 2 – 110% of the principal amount
Year 3 – 105% of the principal amount
Years 4 and 5 – 100% of the principal amount

Now the Company has a reserve-based credit facility agreement of $15.0 million and a second credit facility of $6.25 million, 80% guaranteed by the EDC. Further improving the Company's financial position is the five-year term nature of the EDC backed credit facility, having an annual review date on the reserve-based credit facility which is 11 months into the future and the injection of $1.25 million from the convertible debenture offering. These credit arrangements, the injection of capital by the Company's shareholders and an overall improving oil and gas environment will allow the Company to reassess the requirement for the going concern disclosure in its December 31, 2020 audited financial statements.

Clearview Resources Ltd.
Management Discussion and Analysis (MD&A)
September 30, 2020

The management discussion and analysis ("MD&A") is a review of the financial position and results of operations of the Company for the three and nine months ended September 30, 2020 and 2019. The MD&A should be read in conjunction with the Company's unaudited condensed interim financial statements and accompanying notes for the three and nine months ended September 30, 2020 and 2019 and the audited financial statements and accompanying notes for the periods ended December 31, 2019 and 2018. The unaudited condensed interim financial statements have been prepared in accordance with International Accounting Standard 34, Interim Financial Reporting. Unless otherwise noted, all dollar amounts in the tables are expressed in thousands of Canadian dollars ($000's), except per unit amounts. The MD&A has been prepared and approved by the Board of Directors as of November 27, 2020.

Refer to page 26 for information about non-GAAP measures, page 27 for information on forward-looking statements and page 28 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

	Nine months ended		Periods ended		
	Sept. 30 2020	Sept. 30 2019	Dec. 31 2019	Dec. 31 2018	Mar. 31 2018
Oil and natural gas sales	11,263	19,175	25,687	16,273	20,286
Adjusted funds flow (1)	1,530	4,223	5,494	1,852	3,679
Per share – basic	0.13	0.37	0.48	0.18	0.44
Per share – diluted	0.13	0.37	0.48	0.18	0.44
Cash flow from operations	1,728	3,860	4,980	1,088	4,337
Per share – basic	0.15	0.34	0.43	0.11	0.51
Per share - diluted	0.15	0.34	0.43	0.11	0.51
Net earnings (loss)	(27,733)	(3,241)	(8,768)	(4,832)	(8,460)
Per share – basic	(2.38)	(0.28)	(0.76)	(0.48)	(1.00)
Per share – diluted	(2.38)	(0.28)	(0.76)	(0.48)	(1.00)
Total assets	53,307	94,019	80,038	80,752	72,714
Total long term liabilities	25,350	31,769	23,420	22,645	18,873
Net debt (1)	14,203	15,793	15,358	18,186	14,154
Total capital expenditures – net (2)	322	1,601	1,955	6,172	6,375

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

In the nine months ended September 30, 2020, revenues were lower than the comparative period of 2019 due to lower oil prices and lower production volumes from wells being shut-in for part of the second quarter. The shut-in production was primarily operated oil volumes and natural gas associated with the oil production due to low prices for oil and natural gas liquids stemming from the COVID-19 pandemic. The significant decrease in revenue of $7.9 million was partially offset by an increase in realized gains on risk management contracts of $1.1 million, lower royalties of $1.4 million, lower operating costs of $1.8 million, lower transportation costs of $0.3 million and lower general and administrative expenses of $ 0.6 million, resulting in adjusted funds flow being lower by $2.7 million versus the comparative nine months of the prior year. Cash flow from operations was reduced due to the lower adjusted funds flow revenue but partially offset by a positive change in operating working capital of $0.4 million. The net loss for the nine months ended September 30, 2020 increased to $27.7 million, an increase of $24.5 million primarily due to lower adjusted funds flow by $2.7 million and an impairment expense of $22.3 million incurred in the first three months of 2020. Net debt was reduced over the first nine months of 2020 by $1.2 million as adjusted funds flow in excess of capital expenditures was applied against working capital and bank debt.

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 the 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.

For the fiscal year ended December 31, 2018, oil and natural gas sales and adjusted funds flow were reduced by 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.

DISCUSSION OF OPERATIONS

Acquisitions and dispositions

(a) Acquisition of assets

During the nine months ended September 30, 2020, the Company acquired working interests of joint venture partners in 9 gross (3.5 net) wells in its Central Alberta Oil CGU. The joint venture partners paid Clearview $261 thousand to acquire their working interests, representing the value of the assets less the cost of decommissioning obligations of $296 thousand.

(b) Acquisition of Private Co. assets

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

(c) Disposition of assets

In the third quarter of 2020, the Company closed the disposition of a non-operated minor working interest in a natural gas property in its Central Alberta Gas CGU for nil proceeds. No gain or loss was recorded in earnings related to the disposition. The disposition resulted in a reduction of $88 thousand in decommissioning obligations.

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.

Capital expenditures and drilling activity

	Three months ended			Nine months ended		
	Sept. 30 2020	Sept. 30 2019	% Change	Sept. 30 2020	Sept. 30 2019	% Change
Land	-	-	-	3	-	100
Drilling, completions, equipping	50	318	(84)	300	628	(52)
Facilities	163	143	14	253	436	(42)
Other	20	(319)	(106)	27	56	(52)
Capital invested	233	142	64	583	1,120	(48)
Disposition of properties	-	(25)	(100)	-	(29)	(100)
Net capital invested	233	117	99	583	1,091	(47)
Acquisition of properties	(114)	(1)	11,300	(261)	510	(151)
Total capital expenditures	119	116	3	322	1,601	(80)

The Company spent less than its adjusted funds flow on capital expenditures in the three and nine months ended September 30, 2020. The capital expenditures incurred were primarily for facility upgrades and a few workovers.

Production

Production is summarized in the following table:

	Three months ended			Nine months ended		
	Sept. 30 2020	Sept. 30 2019	% Change	Sept. 30 2020	Sept. 30 2019	% Change
Oil – bbl/d	531	641	(17)	478	705	(32)
Natural gas liquids – bbl/d	410	501	(18)	410	475	(14)
Total liquids – bbl/d	941	1,142	(18)	888	1,180	(25)
Natural gas – mcf/d	7,143	7,487	(5)	6,973	7,428	(6)
Total – boe/d	2,132	2,389	(11)	2,050	2,419	(15)

Production for the quarter ended September 30, 2020 decreased by 11% versus the respective comparative period. The decrease in production was partially due to lower oil production of 17% as not all shut-in oil production was brought back on-stream at the very beginning of the third quarter and also due to natural declines. Natural gas liquids, generally associated with natural gas production, decreased 18% for the quarter ended September 30, 2020 versus the comparative period. The decrease was primarily due to lower natural gas production of 5% and the increased production of natural gas processed through facilities that extract fewer natural gas liquids.

For the nine months ended September 30, 2020, overall production decreased by 15% due to the shut-in of volumes in the second quarter and natural declines as no new wells have been drilled in the past 23 months. In addition, minimal spending has been incurred on workovers or optimization projects in 2020. Instead the Company's adjusted funds flow has been directed at the repayment of net debt.

Clearview's production portfolio for the nine months ended September 30, 2020 was weighted 23% to oil, 20% to natural gas liquids and 57% to natural gas. For the nine months ended September 30, 2019 the production mix was weighted 29% to oil, 20% to natural gas liquids and 51% to natural gas. The change in product mix over the first nine months of 2020 has been influenced by the shut-in of operated oil production and associated natural gas in the second quarter of this year. A 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.

Benchmark prices and economic parameters

	Three months ended			Nine months ended		
	Sept. 30 2020	Sept. 30 2019	% Change	Sept. 30 2020	Sept. 30 2019	% Change
Oil – West Texas Intermediate ("WTI") (US $/bbl)	40.94	56.45	(27)	38.29	57.06	(33)
Oil – Edmonton Par ($/bbl)	49.88	68.38	(27)	43.69	69.58	(37)
Differential – Light oil ($/bbl) (1)	(4.65)	(6.16)	(25)	(8.12)	(6.25)	30
NGLs - Pentane ($/bbl)	51.73	68.26	(24)	47.83	70.21	(32)
NGLs – Butane ($/bbl)	19.15	23.61	(19)	22.70	18.06	26
NGLs – Propane ($/bbl)	14.20	13.02	9	16.35	13.91	18
Natural gas – AECO ($/mcf)	2.24	0.92	143	2.10	1.51	39
Exchange rate – US$/Cdn$	0.7509	0.7573	(1)	0.7392	0.7524	(2)

(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 the three months ended September 30 decreased from an average of US $56.45 per barrel in 2019 to only US $40.94 per barrel in 2020 resulting in a 27% decrease. This significant decrease in WTI was a result of an over-supply of crude oil from Saudi Arabia and Russia, resulting in a price war early in 2020 and compounded by a drop in the demand for oil as a result of the COVID-19 pandemic and the shutdown of economies around the world. Canadian oil prices decreased by 27% in the three months ended September 30, 2020 compared to the same quarter in 2019 as the Canadian light oil differential or discount narrowed by 25 percent over the same comparative quarter to offset a portion of the drop in WTI.

Benchmark oil prices in the nine months ended September 30 decreased from an average of US $57.06 per barrel in 2019 to only US $38.29 per barrel in 2020 resulting in a 33% decrease. Canadian oil prices decreased by 37% in the nine months ended September 30, 2020 compared to the same quarter in 2019 as the Canadian light oil differential or discount widened by 30 percent over the same comparative period on top of the drop in WTI.

Pentane prices decreased over the three and nine months ended September 30, 2020 in a very similar manner to WTI pricing and Canadian light oil prices with decreases of 24% and 32%, respectively, versus the comparative periods of 2019.

Butane prices averaged $19.15 per barrel for the quarter ended September 30, 2020, a decrease of 19% from the same quarter of 2019. Butane prices averaged $22.70 per barrel for the nine months ended September 30, 2020, an increase of 26% from the same period of 2019. The recovery in butane prices over the nine month period of 2020 versus the same period in 2019 is largely due to the balancing of demand versus supply of butane in the Canadian market.

Propane prices averaged $14.20 per barrel for the quarter ended September 30, 2020, an increase of 9% compared to the same quarter of 2019. Propane prices averaged $16.35 per barrel for the nine months ended September 30, 2020, an increase of 18% from the same period of 2019. Similar to butane, the recovery in propane prices over the nine month period of 2020 versus 2019 is largely due to the removal of an oversupply of propane in the Canadian market.

AECO natural gas prices averaged $2.24 per mcf for the three months ended September 30, 2020, an increase of 143% as compared to the same quarter of 2019. The increase is largely a result of reduced production associated with industry wide shut-in of natural gas associated with oil production, the continued expansion of the Nova system and the low supply of natural gas in storage in Alberta. For the nine months ended September 30, 2020, AECO natural gas prices are higher by 39% than the comparative period of 2019 as AECO pricing has been very strong throughout the year due to the low supply of natural gas in storage in Alberta.

Realized sales prices

	Three months ended			Nine months ended		
	Sept. 30 2020	Sept. 30 2019	% Change	Sept. 30 2020	Sept. 30 2019	% Change
Oil – $/bbl	43.67	63.04	(31)	40.16	64.88	(38)
NGLs – $/bbl	22.51	20.45	10	18.61	26.33	(29)
Natural gas – $/mcf	2.11	1.02	107	2.05	1.61	27
Total – $/boe	22.29	24.37	(9)	20.06	29.04	(31)

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 September 30, 2020, the Company's realized oil price was lower by 31% than the comparative quarter as a result of a significant drop in benchmark pricing.

Natural gas liquids prices were higher by 10% in the third quarter of the current year as compared to the same quarter of the prior year. This increase was primarily due to higher prices received for the Company's ethane, propane and butane production.

The Company's realized price for natural gas was higher by 107% for the three months ended September 30, 2020. This compares to a 145% increase in the benchmark AECO price over the same period. For the majority of the Company's natural gas production, the Company receives AECO plus a slightly positive adjustment for heating content from natural gas liquids left in the natural gas stream. A portion of the Company's natural gas production which is sold in Alberta received a lower price adjustment, non AECO based, in 2020 than in 2019 which had a negative effect on the Company's premium to AECO in 2020.

On a boe basis, the Company's realized price was 9% lower for the three months ended September 30, 2020 than the comparative period, due to lower prices received for its oil.

Revenues

Oil and natural gas sales

	Three months ended			Nine months ended		
	Sept. 30 2020	Sept. 30 2019	% Change	Sept. 30 2020	Sept. 30 2019	% Change
Oil	2,133	3,715	(43)	5,257	12,491	(58)
Natural gas liquids	850	942	(10)	2,089	3,418	(39)
Total liquids	2,983	4,657	(36)	7,346	15,909	(54)
Natural gas	1,388	700	98	3,917	3,266	20
Total sales	4,371	5,357	(18)	11,263	19,175	(41)
Per boe	22.29	24.37	(9)	20.06	29.04	(31)

Crude oil sales decreased 43% in the three months ended September 30, 2020 as a decrease in oil production volumes of 17% was compounded by a decrease of 31% in realized oil prices.

Natural gas liquids revenues were lower by 10% in the quarter ended September 30, 2020 as production decreases of 18% were offset by higher realized natural gas liquids prices by 10%.

Natural gas revenue increased 98% in the quarter ended September 30, 2020 as lower production volumes of 5% were sold for a 108% higher realized natural gas price than in the comparative quarter.

The 18% decrease in oil and gas sales for the three months ended September 30, 2020 is due to both lower production volumes being sold in the quarter by 11% and an average lower price received per boe by 9% than the comparative quarter. The 41% decrease in oil and gas sales for the nine months ended September 30, 2020 is due to both lower production volumes being sold in the period by 15% and an average lower price received per boe of 31% than the comparative period.

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 receives 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 Carstairs, East Crossfield, Garrington, Northville and Wilson Creek properties. The Company earns revenue from processing fees on third party production volumes utilizing these facilities, a fee for service arrangement.

	Three months ended			Nine months ended		
	Sept. 30 2020	Sept. 30 2019	% Change	Sept. 30 2020	Sept. 30 2019	% Change
Processing income	142	176	(19)	399	499	(20)
Per boe	0.72	0.80	(10)	0.71	0.76	(7)

Processing income decreased to $142 thousand for the three months ended September 30, 2020, a 19% decrease from the comparative quarter ended September 30, 2019. For the nine months ended September 30, 2020, processing income decreased 20% versus the comparative period of 2019. Processing income decreased due to lower third party volumes being processed at the Company's facilities.

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 September 30, 2020.

Commencement Date	Expiry Date	Units	Volume	Underlying Commodity	Fixed Price
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
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
November 1, 2020	March 31, 2021	GJ/day	1,000	AECO 5A – Financial	$2.91
January 1, 2021	March 31, 2021	GJ/day	1,000	AECO 5A – Financial	$2.79
January 1, 2021	December 31, 2021	GJ/day	1,000	AECO 5A – Financial	$2.10
April 1, 2021	October 1, 2021	GJ/day	2,000	AECO 5A – Financial	$1.86
January 1, 2021	December 31, 2021	Bbls/day	Sold 150	US WTI – Call Option	$65.00

The Company's crude oil revenue is exposed to fluctuations in the US/Cdn exchange rate as the benchmark price of oil is based in US dollars. The price received by the Company for its oil production is calculated in Cdn dollars based on the average US/Cdn exchange rate for the month. Clearview had the following financial foreign exchange rate swaps outstanding at September 30, 2020 to mitigate the volatility of foreign exchange rates on a portion of its oil revenues. The realized gains or losses on the foreign exchange rate swap are recorded in oil and natural gas sales on the statement of operations.

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

The Company has a variable rate credit facility outstanding and consequently the Company is exposed to fluctuations in interest rates. The Company had the following financial interest rate swaps outstanding as of September 30, 2020. The realized gains or losses on the interest rate swaps are recorded in finance costs on the statement of operations.

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%

The mark to market value of the instruments contracted and outstanding at September 30, 2020 was an unrealized loss of $0.7 million, classified as a current liability (at December 31, 2019 – unrealized loss of $0.2 million, classified as a current liability). The fair value of these contracts is based on the forward prices and market values provided by independent sources and represents the amount that would have been paid to counterparties to settle the contracts at the end of the reporting period. The unrealized loss in the nine months ended September 30, 2020 is the difference between the fair values of the contracts at September 30, 2020 and the fair values of outstanding contracts at the respective prior reporting period. Due to the volatility of commodity prices, interest rates and foreign exchange rates, actual amounts may differ from these estimates.

The change in the mark to market value during the nine months ended September 30, 2020 resulted in an unrealized loss of $0.5 million (nine months ended September 30, 2019 – unrealized gain of $4 thousand) which was recorded in the statement of operations. The realized gain for the nine months ended September 30, 2020 was $1.3 million (nine months ended September 30, 2019 – realized gain of $0.1 million).

Management monitors the forward price market for oi, natural gas, interest rates and foreign exchange rates 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			Nine months ended		
Amount	Sept. 30 2020	Sept. 30 2019	% Change	Sept. 30 2020	Sept. 30 2019	% Change
Crown – oil	50	301	(83)	241	911	(74)
Crown – natural gas liquids	240	207	16	588	876	(33)
Crown – natural gas	84	26	223	271	183	48
Gas cost allowance	(332)	(299)	11	(786)	(1,099)	(28)
Total Crown	42	235	(82)	314	871	(64)
Freehold	73	182	(60)	217	603	(64)
Gross over-riding	93	153	(39)	255	696	(63)
Total royalties	208	570	(64)	786	2,170	(64)
Per boe	1.06	2.59	(59)	1.40	3.29	(57)

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.

	Three months ended			Nine months ended		
Royalty rate	Sept. 30 2020	Sept. 30 2019	% Change	Sept. 30 2020	Sept. 30 2019	% Change
Total Crown	0.9%	4.4%	(80)	2.8%	4.5%	(38)
Freehold	1.7%	3.4%	(50)	1.9%	3.1%	(39)
Gross over-riding	2.1%	2.9%	(28)	2.3%	3.6%	(36)
Total royalties	4.7%	10.7%	(56)	7.0%	11.2%	(37)

The overall royalty burden for the three months ended September 30, 2020 decreased by 56% to a rate of 4.7% versus 10.7% for the comparative period. Crown royalty rates were lower by 80% due to low prices received for the Company's oil production. Crown royalties on natural gas and natural gas liquids production were largely offset by gas cost allowance. Freehold royalties and gross over-riding royalties decreased due to lower realized prices.

The overall royalty burden for the nine months ended September 30, 2020 decreased by 37% to a rate of 7.0% versus 11.2% for the comparative period. The decrease was a result of lower oil and natural gas liquids prices and reduced production volumes.

Transportation expenses

	Three months ended			Nine months ended		
	Sept. 30 2020	Sept. 30 2019	% Change	Sept. 30 2020	Sept. 30 2019	% Change
Transportation costs	319	318	-	881	1,086	(19)
Per boe	1.63	1.44	13	1.57	1.64	(4)

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 approximately 74% 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 in 2020.

Transportation expense per boe increased 13% in the three months ended September 30, 2020 due to more deliveries of smaller truck loads to main market hubs or terminals. For the nine months ended September 30, 2020, transportation costs were lower by 19% resulting in a decrease in transportation costs per boe of 4% versus the comparative period.

Operating expenses

	Three months ended			Nine months ended		
	Sept. 30 2020	Sept. 30 2019	% Change	Sept. 30 2020	Sept. 30 2019	% Change
Operating costs	2,491	3,195	(22)	7,785	9,591	(19)
Per boe	12.70	14.53	(13)	13.87	14.53	(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 September 30, 2020 were $12.70 per boe, lower by 13% than the comparative quarter of the prior year, at $14.53 per boe. This decrease reflects a 22% decrease in costs as austere measures were undertaken and maintained by the Company related to field operations in light of low oil prices and the shut-in of production volumes in the second quarter. These lower costs were partially offset by a 11% decrease in production per day resulting in an overall reduction in operating costs per boe of 13%. Operating costs for the nine months ended September 30, 2020 were lower by 19% versus the comparative period which were partially offset by lower production volumes of 15% over the same period.

General and administrative expenses

	Three months ended			Nine months ended		
	Sept. 30 2020	Sept. 30 2019	% Change	Sept. 30 2020	Sept. 30 2019	% Change
Gross costs	341	584	(42)	1,347	1,940	(31)
Overhead recoveries	(45)	(62)	(27)	(177)	(181)	(2)
Total G&A expenses	296	522	(43)	1,170	1,759	(33)
Per boe	1.51	2.38	(37)	2.08	2.67	(22)

General and administrative costs, net of recoveries, decreased 43% in the three months ended September 30, 2020 versus the comparative period as a result of cost cutting measures undertaken by the Company, primarily including the elimination of contract office positions, the elimination of directors fees in the first quarter of 2020, reduced salaries for staff and management initiated during the second quarter and the collection of $63,000 in the quarter, $178,000 for the nine months of 2020, under the federal Canada Emergency Wage Subsidy program. These and other cost cutting measures undertaken by the Company resulted in a reduction in the general and administrative expenses per boe of 37% in the three months ended September 30, 2020 and a 22% reduction in the nine months ended September 30, 2020 versus their respective comparative periods.

Transaction costs

	Three months ended			Nine months ended		
	Sept. 30 2020	Sept. 30 2019	% Change	Sept. 30 2020	Sept. 30 2019	% Change
Transaction costs	-	1	(100)	-	111	(100)
Per boe	-	-	(100)	-	0.17	(100)

Transactions costs for the nine months ended September 30, 2020 were nil versus $111 thousand in the comparative period for costs associated with the acquisition of assets from a private company which closed on February 22, 2019.

Finance costs

	Three months ended			Nine months ended		
	Sept. 30 2020	Sept. 30 2019	% Change	Sept. 30 2020	Sept. 30 2019	% Change
Interest on bank debt	211	243	(13)	720	810	(11)
Interest rate swaps	13	-	100	24	-	100
Credit facility fees and costs	-	1	(100)	42	51	(18)
Cash finance costs	224	244	(8)	786	861	(9)
Accretion expense (1)	80	110	(27)	198	287	(31)
Total finance costs	304	354	(14)	984	1,148	(14)
Per boe – cash finance costs	1.14	1.11	3	1.40	1.30	8
Per boe – accretion expense	0.41	0.50	(18)	0.35	0.44	(20)

(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 September 30, 2020 decreased by 13%. The decrease was due to the lowering of the bank prime lending rate during the period and outstanding bank debt being reduced by cash flow from operations in excess of capital expenditures.

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

- October 2018 – from 6.70% to 6.95% - increase in prime rate, and
- February 2020 – from 6.95% to 5.45% - decrease in prime rate.

The average rate for prime based borrowings during the nine month period ended September 30, 2020 was 5.78%.

The Company also has the option of borrowing using the lender's guaranteed notes which are subject to a current stamping fee of 5.0% per annum plus the guaranteed note rate for 30, 60, 90 and 180 day terms. Guaranteed notes resulted in an average rate of approximately 5.94% during the nine month period ended September 30, 2020.

In addition, the Company currently pays its lender a standby fee of 1.50% on the difference between the authorized credit facility 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 decreased in the three months ended September 30, 2020 due to a lower inflation rate of 1.11% used in the calculation for the period versus a 2.0% inflation rate used in the comparative period. The lower inflation rate results in lower accretion expense as the carrying value of the decommissioning obligations has to accrete up, over time, to a lower future value.

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 nine months ended September 30, 2020 and the year ended December 31, 2019, no options were granted by the Company.

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			Nine months ended		
	Sept. 30 2020	Sept. 30 2019	% Change	Sept. 30 2020	Sept. 30 2019	% Change
Stock based compensation	46	147	(69)	255	689	(63)
Per boe	0.23	0.67	(66)	0.45	1.04	(57)

Stock based compensation expense for the three and nine months ended September 30, 2020 were lower by 69% and 63%, respectively, versus the comparative periods. The decrease in expense is primarily due to lower monthly expense, two years later, for options granted to a director and numerous employees in the second quarter of 2018.

Depletion, depreciation and impairment

	Three months ended			Nine months ended		
	Sept. 30 2020	Sept. 30 2019	% Change	Sept. 30 2020	Sept. 30 2019	% Change
Depletion	2,100	2,452	(14)	6,004	7,594	(21)
Depreciation	2	2	-	5	6	(17)
Impairment	-	-	-	22,300	-	100
Total	2,102	2,454	(14)	28,309	7,600	272
Per boe – depletion	10.72	11.17	(4)	10.69	11.50	(7)
Per boe - depreciation	-	-	-	0.01	0.01	-
Per boe - impairment	-	-	-	39.71	-	100
Total	10.72	11.17	(4)	50.41	11.51	338

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 decrease in depletion of 14% for the three months ended September 30, 2020 is a combination of lower production volumes by 11% versus the comparative period and a lower depletion rate per boe of production of 4% versus the comparative period. The decrease in depletion of 21% for the nine months ended September 30, 2020 is a combination of lower production volumes by 15% versus the comparative period and a lower depletion rate per boe of production of 7% versus the comparative period.

At March 31, 2020, due to the decline in current and forward oil, natural gas and natural gas liquids prices, Clearview determined there were indicators of impairment present affecting all of its CGU's. As a result, the Company completed an impairment test on its three CGU's, Central Alberta Gas, Central Alberta Oil and Southern Alberta Oil at March 31, 2020 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 10 to 20 percent. The tests indicated an impairment in all three CGU's. For the Central Alberta Gas CGU, the carrying value exceeded the recoverable amount by $13.8 million, the Central Alberta Oil CGU carrying value exceeded the recoverable amount by $7.0 million and the Southern Alberta Oil CGU carrying value exceeded the recoverable amount by $1.5 million. This resulted in a total impairment of $22.3 million.

The following table details the forward pricing used in estimating the recoverable amount of each CGU at March 31, 2020.

	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/gj
2020	29.17	29.22	19.55	10.04	18.27	34.35	1.74
2021	40.45	46.85	35.07	17.08	29.70	50.72	2.20
2022	49.17	59.27	46.87	23.55	37.87	62.80	2.38
2023	53.28	65.02	51.81	26.03	41.80	68.49	2.45
2024	55.66	68.43	54.85	27.57	44.14	71.73	2.53
2025	56.87	69.81	56.29	28.19	45.02	73.16	2.60
2026	58.01	71.24	57.54	28.83	45.95	74.66	2.66
2027	59.17	72.70	58.82	29.49	46.89	76.19	2.72
2028	60.35	74.19	60.12	30.17	47.86	77.75	2.79
2029	61.56	75.71	61.44	30.85	48.84	79.34	2.85
2030	62.79	77.22	62.67	31.47	49.81	80.93	2.91
2031	64.05	78.77	63.92	32.10	50.81	82.55	2.97
2032	65.33	80.34	65.20	32.74	51.83	84.20	3.03
2033	66.63	81.95	66.50	33.40	52.86	85.88	3.09
2034	67.97	83.59	67.83	34.07	53.92	87.60	3.15
2035+	+2.0%/yr	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.

The results of Clearview's impairment tests are sensitive to changes in: quantities of reserves and future production, forward commodity pricing as forecast by three independent reservoir engineering companies, development costs, operating costs, royalty obligations, abandonment costs and discount rates. As such, any changes to these key estimates could decrease or increase the recoverable amounts of assets and result in additional impairment charges or in the reversal of previously recorded impairments charges.

As at March 31, 2020, all else being equal, a 1% change in the discount rate or a 5% change in the forecast operating cash flows would result in the following charge to impairment expense being recognized.

($ thousands)	1% change in discount rate	5% change in cash flows
Central Alberta Gas CGU	652	812
Central Alberta Oil CGU	1,095	957
southern Alberta Oil CGU	8	38
Total	1,755	1,807

Income taxes

	Three months ended			Nine months ended		
	Sept. 30 2020	Sept. 30 2019	% Change	Sept. 30 2020	Sept. 30 2019	% Change
Deferred income tax recovery	-	-	-	-	1,108	(100)
Per boe	-	-	-	-	1.68	(100)

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 September 30, 2020. 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 September 30, 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 2019.

Clearview has no current income taxes payable and has estimated tax pools available against income of $150.5 million, including non-capital tax loss carryforwards of $62.5 million which will expire over the years 2024 to 2038.

Adjusted funds flow

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

	Three months ended			Nine months ended		
	Sept. 30 2020	Sept. 30 2019	% Change	Sept. 30 2020	Sept. 30 2019	% Change
Cash flow provided by (used in) operating activities	874	1,422	(39)	1,728	3,860	(55)
Add back (deduct)						
Decommissioning expenditures	-	229	(100)	53	229	(77)
Change in non-cash working capital	57	(772)	(107)	(251)	134	(287)
Adjusted funds flow (1)	931	879	6	1,530	4,223	(64)

(1) See non-GAAP measures

Adjusted funds flow increased 6% for the three months ended September 30, 2020, as lower revenues from lower production volumes and realized prices were more than offset by lower royalties and operating costs, lower general and administrative costs and lower cash finance costs.

For the three months ended September 30, 2020, cash flow from operations was $0.9 million compared to $1.4 million for the quarter ended September 30, 2019. The decrease of 39% was primarily due to a use of working capital in the third quarter of 2020, partially offset by no decommissioning expenditures in the current quarter, versus the comparative period.

Net loss

	Three months ended			Nine months ended		
	Sept. 30 2020	Sept. 30 2019	% Change	Sept. 30 2020	Sept. 30 2019	% Change
Net earnings (loss)	(1,761)	(2,129)	(17)	(27,733)	(3,241)	756
Per boe	(8.98)	(9.68)	(7)	(49.38)	(4.91)	906
Per share – basic	(0.15)	(0.18)	(17)	(2.38)	(0.28)	750
Per share – diluted	(0.15)	(0.18)	(17)	(2.38)	(0.28)	750

The Company sustained a net loss of $1.8 million for the three months ended September 30, 2020 compared to a net loss of $2.1 million for the comparative period. The decrease in the net loss for the three months ended September 30, 2020 was primarily due to lower depletion expense for the quarter. The increase in the net loss for the nine months ended September 30, 2020 was primarily due to an impairment of $22.3 million as a result of a significant decrease in prices for the Company's oil, natural gas and natural gas liquids reserves.

Netback analysis

	Three months ended			Nine months ended		
Barrel of oil equivalent ($/boe)	Sept. 30 2020	Sept. 30 2019	% Positive (Negative)	Sept. 30 2020	Sept. 30 2019	% Positive (Negative)
Realized sales price	22.29	24.37	(9)	20.06	29.04	(31)
Royalties	(1.06)	(2.59)	59	(1.40)	(3.29)	57
Processing income	0.72	0.80	(10)	0.71	0.76	(7)
Transportation	(1.63)	(1.44)	(13)	(1.57)	(1.64)	4
Operating	(12.70)	(14.53)	13	(13.87)	(14.53)	5
Operating netback (2)	7.62	6.61	15	3.93	10.34	(62)
Realized gain (loss) - risk management contracts	(0.22)	0.89	(125)	2.27	0.19	1,095
General and administrative	(1.51)	(2.38)	37	(2.08)	(2.67)	22
Transaction costs	-	-	-	-	(0.17)	100
Cash finance costs	(1.14)	(1.11)	(3)	(1.40)	(1.30)	(8)
Corporate netback (2)	4.75	4.01	18	2.72	6.39	(57)
Unrealized gain (loss) – risk management contracts	(2.37)	(1.35)	(76)	(0.89)	0.01	(9,000)
Stock based compensation	(0.23)	(0.67)	66	(0.45)	(1.04)	57
Depletion and depreciation	(10.72)	(11.17)	4	(10.70)	(11.51)	7
Impairment	-	-	-	(39.71)	-	(100)
E&E expense	-	(0.11)	100	-	(0.04)	100
Accretion	(0.41)	(0.50)	18	(0.35)	(0.44)	20
Gain on disposal of natural gas assets	-	0.11	(100)	-	0.04	(100)
Deferred income taxes	-	-	-	-	1.68	(100)
Net earnings (loss)	(8.98)	(9.68)	7	(49.38)	(4.91)	(906)

(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 quarter ended September 30, 2020 increased 18% to $4.75 per boe compared to the prior period. The increase is primarily due to lower royalties, operating costs and general and administrative costs per boe more than offsetting the lower realized price per boe in the current period versus the comparative period.

SUMMARY OF QUARTERLY RESULTS

Three months ended	Sep 30 2020	Jun 30 2020	Mar 31 2020	Dec 31 2019	Sep 30 2019	Jun 30 2019	Mar 31 2019	Dec 31 2018
Production								
Oil (bbl/d)	531	320	582	621	641	709	768	668
Natural gas liquids (bbl/d)	410	387	431	494	501	452	473	437
Natural gas (mcf/d)	7,143	6,058	7,716	7,859	7,487	7,153	7,646	6,745
Total (boe/d)	2,132	1,716	2,299	2,425	2,389	2,353	2,515	2,229
Financial								
Oil and natural gas sales	4,371	2,350	4,542	6,512	5,357	6,318	7,500	4,585
Adjusted funds flow (1)	931	83	516	1,271	879	1,280	2,064	511
Per share – basic	0.08	0.01	0.04	0.11	0.08	0.11	0.19	0.05
Per share – diluted	0.08	0.01	0.04	0.11	0.08	0.11	0.19	0.05
Net earnings (loss)	(1,761)	(2,755)	(23,217)	(5,527)	(2,129)	(658)	(454)	(2,083)
Per share – basic	(0.15)	(0.24)	(1.99)	(0.48)	(0.18)	(0.06)	(0.04)	(0.20)
Per share - diluted	(0.15)	(0.24)	(1.99)	(0.48)	(0.18)	(0.06)	(0.04)	(0.20)

(1) See non-GAAP measures.

In the third quarter of 2020, production was higher than the previous quarter due to shut-in production being brought back on-stream. Oil and natural gas sales increased by 86% in the three months ended September 30, 2020 from the previous quarter due to higher production volumes by 24% and higher realized sales prices. Higher oil and natural gas sales were partially offset by primarily much lower realized gains on commodity contracts resulting in higher adjusted funds flow than the second quarter of 2020. The net loss for the three months ended September 30, 2020 was $1.8 million compared to $2.8 million in the previous quarter. The major difference in the net loss was the higher adjusted funds flow in the third quarter versus the second quarter of 2020.

In the second quarter of 2020, production was lower than the previous quarter due to the shut-in of the Company’s operated light oil production and associated natural gas production. Oil and natural gas sales were reduced significantly in the three months ended June 30, 2020 from the previous quarter due to lower production and lower realized sales prices other than natural gas prices. Lower oil and natural gas sales were only partially offset by realized gains on commodity contracts and reduced costs amongst all cost categories other than interest costs resulting in lower adjusted funds flow than the first quarter of 2020. The net loss for the three months ended June 30, 2020 was $2.8 million compared to $23.2 million in the previous quarter. Excluding the impairment charge of $22.3 million in the first quarter of 2020, the major differences were an unrealized loss on financial instruments of $1.1 million in the second quarter of 2020 versus an unrealized gain of $1.1 million in the first quarter of 2020.

In the first quarter of 2020, production was lower from the previous quarter due to normal production declines. Oil and natural gas sales were reduced significantly in the three months ended March 31, 2020 from the previous quarter due to lower production and lower realized sales prices. Lower oil and natural gas sales were only partially offset by realized gains on commodity contracts resulting in lower adjusted funds flow than the fourth quarter of 2019. The net loss for the three months ended March 31, 2020 was $23.2 million compared to $5.5 million in the previous quarter. The major differences were an unrealized gain on financial instruments of $1.1 million in the first quarter of 2020 and an increase in impairment expense of $18.5 million in the first quarter of 2020.

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 2019 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 2019, 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 2019 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 nine months ended September 30, 2020 as net debt was reduced by $1.2 million as adjusted funds flow in excess of capital expenditures and collected receivables were used to repay outstanding bank debt. As a result, net debt is $14.2 million at September 30, 2020, down from $15.4 million at December 31, 2019, with the components set out below:

As at	September 30, 2020	December 31, 2019
Trade and other receivables	2,349	2,940
Prepaid expenses and deposits	668	606
Bank debt	(13,411)	(14,807)
Accounts payable and accrued liabilities	(3,387)	(3,675)
Decommissioning obligations	(422)	(422)
Net debt (1)	(14,203)	(15,358)

(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. The Company monitors net debt as a key component of managing liquidity risk and determining capital resources available to finance future development.

As at September 30, 2020, the Company had a demand revolving operating facility with ATB Financial with a limit of $18.5 million (December 31, 2019 - $18.5 million) of which $13.4 million (December 31, 2019 - $14.8 million) was drawn. The interest rate is prime plus 4% or CDOR plus 5.0% for guaranteed notes and the loan agreement requires monthly interest payments only.

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 2.1 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 September 30, 2020 was 2.24.

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.

During the first quarter of 2020, 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 30, 2021 and may be cancelled by either the Company or the landlord on one month's notice to the other party.

The following is a summary of the Company's future minimum contractual obligations and commitments as of September 30, 2020.

	2020	2021	2022	2023	Thereafter
Bank debt	13,411	-	-	-	-
Accounts payable and accrued liabilities	3,387	-	-	-	-
Decommissioning obligations	422	422	422	422	24,084
Gas transportation	54	93	4	-	-
Office lease	27	54	-	-	-
Total	17,301	569	426	422	24,084

OFF-BALANCE SHEET ARRANGEMENTS

The Company has not engaged in any off-balance sheet arrangements. The commodity contracts for oil and natural gas prices disclosed in the MD&A 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 November 26, 2020, the Company has 11,671,387 voting common shares outstanding and 1,050,500 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	341,500	551,999	893,499
Vesting in the future in the three months ending:			
December 31, 2020	-	2,500	2,500
June 30, 2021	-	154,501	154,501
Total	341,500	716,667	1,050,500

For further details about the options refer to Note 9 to the financial statements as at and for the nine months ended September 30, 2020.

RELATED PARTY TRANSACTIONS

There were no related party transactions in the nine months ended September 30, 2020.

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 2018. Certain estimates and judgments are described in Note 2 to the audited financial statements for the periods ended December 31, 2019 and 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 1.11% 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 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 nine months ended September 30, 2020, the Company adopted the following new accounting standard.

Business Combinations

On January 1, 2020, the Company adopted the amendments to IFRS 3, “Business Combinations”, to clarify whether a transaction results in an asset acquisition or a business acquisition. 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. The standard will be applied prospectively. No business combinations were completed during the nine months ended September 30, 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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