Clearview Resources Ltd.

Management Discussion and Analysis (MD&A)

June 30, 2020

COVID-19 and Economic Uncertainty

Against a backdrop of OPEC and non-OPEC nations initiating an oil price war in the first quarter, in March 2020, the World Health Organization declared a global pandemic following the rapid spread of the coronavirus ("COVID-19"). The subsequent responses and measures initiated by governments worldwide, intended to limit the spread of the pandemic, resulted in a sudden decline in economic activity and a significant increase in economic uncertainty. The reduction in economic activity significantly reduced global demand for commodities including crude oil, natural gas and natural gas liquids and led to a further dramatic decline in crude oil prices. These events have resulted in an environment which has adversely affected the Company's operational results and financial position.

Although the global economies have recently begun to reopen and government authorities are easing restrictions, the situation remains dynamic and the ultimate duration and magnitude of COVID-19 on the global economy and the financial effect on Clearview is unknown at this time.

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 $14.4 million outstanding on the credit facility at June 30, 2020 and has $13.8 million outstanding as of August 26, 2020.

The next borrowing base redetermination is currently scheduled to be completed by no later than September 15, 2020. The available lending limits are based on the lender's interpretation of the Company's reserves and future commodity prices. While the Company maintains an ongoing dialogue with its lender, 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 August 25, 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 temporarily shut-in a significant portion of its operated production to preserve the value of its reserves. This shut-in of production for a period of time in the second quarter 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. Recent improvements in realized sales prices and the forward price curves have improved the Company's ability to generate cash flow from operations and shut-in production has been brought back on-stream. 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.

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Management Discussion and Analysis (MD&A)
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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 six months ended June 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 six months ended June 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 August 25, 2020.

Refer to page 25 for information about non-GAAP measures, page 26 for information on forward-looking statements and page 27 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

	Six months ended		Periods ended		
	June 30 2020	June 30 2019	Dec. 31 2019	Dec. 31 2018	Mar. 31 2018
Oil and natural gas sales	6,892	13,818	25,687	16,273	20,286
Adjusted funds flow (1)	599	3,344	5,494	1,852	3,679
Per share – basic	0.05	0.30	0.48	0.18	0.44
Per share – diluted	0.05	0.30	0.48	0.18	0.44
Cash flow from operations	854	2,438	4,980	1,088	4,337
Per share – basic	0.07	0.22	0.43	0.11	0.51
Per share - diluted	0.07	0.22	0.43	0.11	0.51
Net earnings (loss)	(25,972)	(1,112)	(8,768)	(4,832)	(8,460)
Per share – basic	(2.23)	(0.10)	(0.76)	(0.48)	(1.00)
Per share – diluted	(2.23)	(0.10)	(0.76)	(0.48)	(1.00)
Total assets	55,138	95,899	80,038	80,752	72,714
Total long term liabilities	25,149	31,043	23,420	22,645	18,873
Net debt (1)	15,015	16,327	15,358	18,186	14,154
Total capital expenditures – net (2)	256	1,485	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.

In the six months ended June 30, 2020, revenues were lower than the comparative quarter due to lower production volumes due to wells being shut-in for part of the quarter, 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 was partially offset by an increase in realized gains on commodity contracts of $1.4 million and lower royalties on revenue of $1.0 million resulting in adjusted funds flow being lower by $2.7 million versus the comparative six months of the prior year. Cash flow from operations was reduced due to the lower revenue but partially offset by a positive change in operating working capital of $1.2 million. The net loss for the six months ended June 30, 2020 increased to $26.0 million, an increase of $24.9 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 six months of 2020 by $0.3 million as adjusted funds flow in excess of capital expenditures was applied against working capital and bank debt.

DISCUSSION OF OPERATIONS

Acquisitions and dispositions

(a) Acquisition of assets

During the six months ended June 30, 2020, the Company acquired working interests of joint venture partners in 7 gross (2.9 net) wells in its Central Alberta Oil CGU. The joint venture partners paid Clearview $147 thousand to acquire their working interests, representing the value of the assets less the cost of decommissioning obligations of $182 thousand (twelve months ended December 31, 2019 - $16 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

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			Six months ended		
	June 30 2020	June 30 2019	% Change	June 30 2020	June 30 2019	% Change
Land	-	-	-	3	-	100
Drilling, completions, equipping	4	211	(92)	250	310	(19)
Facilities	6	200	(97)	90	293	(69)
Other	(2)	342	(100)	7	375	(98)
Capital invested	8	753	(99)	350	978	(64)
Disposition of properties	-	-	-	-	(4)	(100)
Net capital invested	8	753	(99)	350	974	(64)
Acquisition of properties	(14)	19	(174)	(147)	511	(129)
Total capital expenditures	(6)	772	(101)	203	1,485	(86)

The Company spent less than its adjusted funds flow on capital expenditures in the three and six months ended June 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			Six months ended		
	June 30 2020	June 30 2019	% Change	June 30 2020	June 30 2019	% Change
Oil – bbl/d	320	709	(55)	451	738	(39)
Natural gas liquids – bbl/d	387	452	(14)	409	462	(11)
Total liquids – bbl/d	707	1,161	(39)	860	1,200	(28)
Natural gas – mcf/d	6,058	7,153	(15)	6,887	7,398	(7)
Total – boe/d	1,716	2,353	(27)	2,008	2,434	(18)

Production for the quarter ended June 30, 2020 decreased by 27% versus the respective comparative period. The decrease in production was primarily due to lower oil production of 55% as the Company chose to shut-in its operated oil production and the associated gas volumes to preserve the value of the reserves. Low oil prices and low prices for natural gas liquids, benchmarked from oil prices, resulted in negative field netbacks for these products for much of the quarter due to the economic crisis caused by the COVID-19 pandemic. Natural gas liquids, generally associated with natural gas production, decreased 14% for the quarter ended June 30, 2020 versus the comparative period. The decrease was primarily due to lower natural gas production of 15% over the same comparative time period. By the end of the second quarter of 2020, Clearview had begun selling oil and the associated gas production from several fields brought back on-stream and selling oil which was produced to storage tanks before shut-in operations were undertaken.

For the six months ended June 30, 2020, overall production decreased by 18% due to the shut-in of volumes in the second quarter and natural declines as no new wells have been drilled in the past 20 months as the Company's adjusted funds flow has been directed at the repayment of net debt.

Clearview's production portfolio for the six months ended June 30, 2020 was weighted 22% to oil, 20% to natural gas liquids and 58% to natural gas. For the six months ended June 30, 2019 the production mix was weighted 30% to oil, 19% to natural gas liquids and 51% to natural gas. The change in product mix over the first six 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 as discussed earlier. 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.

Benchmark prices and economic parameters

	Three months ended			Six months ended		
	June 30 2020	June 30 2019	% Change	June 30 2020	June 30 2019	% Change
Oil – West Texas Intermediate ("WTI") (US $/bbl)	27.84	59.84	(53)	37.00	57.35	(35)
Oil – Edmonton Par ($/bbl)	29.84	73.84	(60)	40.66	70.19	(42)
Differential – Light oil ($/bbl) (1)	8.73	6.18	41	9.80	6.28	56
NGLs - Pentane ($/bbl)	31.57	73.73	(57)	45.91	71.18	(36)
NGLs – Butane ($/bbl)	14.37	24.43	(41)	24.51	15.17	62
NGLs – Propane ($/bbl)	20.57	12.31	67	17.41	14.35	21
Natural gas – AECO ($/mcf)	2.01	1.03	95	2.03	1.83	11
Exchange rate – US$/Cdn$	0.7218	0.7478	(3)	0.7333	0.7500	(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 June 30 decreased from an average of US $59.84 per barrel in 2019 to only US $27.84 per barrel in 2020 resulting in a 53% 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 and 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 60% in the three months ended June 30, 2020 compared to the same quarter in 2019 as the Canadian light oil differential or discount widened by 41 percent over the same comparative quarter on top of the drop in WTI.

Benchmark oil prices in the six months ended June 30 decreased from an average of US $57.35 per barrel in 2019 to only US $37.00 per barrel in 2020 resulting in a 35% decrease. Canadian oil prices decreased by 42% in the six months ended June 30, 2020 compared to the same quarter in 2019 as the Canadian light oil differential or discount widened by 56 percent over the same comparative period on top of the drop in WTI.

Pentane prices decreased over the first three and six months of 2020 in a very similar manner to WTI pricing and Canadian light oil prices with decreases of 57% and 36%, respectively, versus the comparative periods of 2019.

Butane prices averaged $14.37 per barrel for the quarter ended June 30, 2020, a decrease of 41% from the same quarter of 2019. Butane prices averaged $24.51 per barrel for the six months ended June 30, 2020, an increase of 62% from the same period of 2019.

Propane prices averaged $20.57 per barrel for the quarter ended June 30, 2020, an increase of 67% from the same quarter of 2019. Propane prices averaged $17.41 per barrel for the six months ended June 30, 2020, an increase of 21% from the same period of 2019.

AECO natural gas prices averaged $2.01 per mcf for the three months ended June 30, 2020, an increase of 95% as compared to the same quarter of 2019. The increase is largely a result of reduced production associated with industry wide shut-in production of associated natural gas and a low supply of natural gas in storage in Canada. For the six months ended June 30, 2020, AECO natural gas prices are higher by 11% than the comparative period of 2019 as AECO pricing in the first quarter of 2019 was very strong due to very cold winter weather.

Realized sales prices

	Three months ended			Six months ended		
	June 30 2020	June 30 2019	% Change	June 30 2020	June 30 2019	% Change
Oil – $/bbl	26.31	69.12	(62)	38.07	65.69	(42)
NGLs – $/bbl	14.79	26.19	(44)	16.63	29.58	(44)
Natural gas – $/mcf	1.93	1.20	60	2.02	1.92	5
Total – $/boe	15.05	29.51	(49)	18.86	31.37	(40)

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 June 30, 2020, the Company's realized oil price was lower by 62% than the comparative quarter as a result of a significant drop in benchmark pricing and a widening of light oil price differentials.

Natural gas liquids prices were lower by 44% in the second quarter of the current year as compared to the same quarter of the prior year. This decrease was primarily due to lower benchmark oil prices, which influence the pricing of natural gas liquids and the 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 prior year.

The Company's realized price for natural gas was higher by 60% for the three months ended June 30, 2020. This compares to a 95% 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 much lower price adjustment, non AECO based, in 2020 than in 2019 which had a negative affect on the Company's premium to AECO in 2020.

On a boe basis, the Company's realized price was 49% lower for the three months ended June 30, 2020 than the comparative period, due to lower prices received for all of its products other than natural gas.

Revenues

Oil and natural gas sales

	Three months ended			Six months ended		
	June 30 2020	June 30 2019	% Change	June 30 2020	June 30 2019	% Change
Oil	765	4,457	(83)	3,124	8,776	(64)
Natural gas liquids	521	1,077	(52)	1,239	2,476	(50)
Total liquids	1,286	5,534	(77)	4,363	11,252	(61)
Natural gas	1,064	784	36	2,529	2,566	(1)
Total sales	2,350	6,318	(63)	6,892	13,818	(50)
Per boe	15.05	29.51	(49)	18.86	31.37	(40)

Crude oil sales decreased 83% in the three months ended June 30, 2020 as a decrease in oil production volumes of 55% was compounded by a decrease of 62% in realized oil prices.

Natural gas liquids revenues were lower by 52% in the quarter ended June 30, 2020 as production decreases of 14 were compounded by lower realized natural gas liquids prices by 44%.

Natural gas revenue increased 36% in the quarter ended June 30, 2020 as lower production volumes by 15% were sold for a 60% higher realized natural gas price than in the comparative quarter.

The 63% decrease in oil and gas sales for the three months ended June 30, 2020 is due to both lower production volumes being sold in the quarter by 27% and an average lower price received per boe by 49% than the comparative quarter. The 50% decrease in oil and gas sales for the six months ended June 30, 2020 is due to both lower production volumes being sold in the quarter by 18% and an average lower price received per boe by 40% than the comparative quarter.

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 quarter. 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, 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			Six months ended		
	June 30 2020	June 30 2019	% Change	June 30 2020	June 30 2019	% Change
Processing income	128	158	(19)	257	323	(20)
Per boe	0.82	0.74	11	0.70	0.73	(4)

Processing income decreased to $128 thousand for the three months ended June 30, 2020, a 19% decrease from the comparative quarter ended June 30, 2019. For the six months ended June 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 June 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
January 1, 2020	December 31, 2020	GJ/day	1,000	AECO 5A – Financial	$2.10
April 1, 2021	October 31, 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 June 30, 2020 to mitigate the volatility of foreign exchange rates on a portion of its oil revenues.

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 June 30, 2020.

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 June 30, 2020 was an unrealized loss of $0.3 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 asset that would have been received from the counterparties to settle the contracts at the end of the reporting period. The unrealized loss in the six months ended June 30, 2020 is the difference between the fair values of the contracts at June 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 six months ended June 30, 2020 resulted in an unrealized loss of $37 thousand (six months ended June 30, 2019 – unrealized gain of $0.3 million) which was recorded in the statement of operations. The realized gain for the six months ended June 30, 2020 was $1.3 million (six months ended June 30, 2019 – realized loss of $69 thousand).

The Company has executed additional commodity price contracts for its natural gas production subsequent to June 30, 2020 as follows:

Commencement Date	Expiry Date	Units	Volume	Underlying Commodity	Fixed Price
January 1, 2021	March 31, 2021	GJ/day	1,000	AECO 5A - Financial	$2.79

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

Amount	Three months ended June 30 2020	June 30 2019	% Change	Six months ended June 30 2020	June 30 2019	% Change
Crown – oil	14	339	(96)	191	611	(69)
Crown – natural gas liquids	59	324	(82)	348	669	(48)
Crown – natural gas	73	65	12	187	157	19
Gas cost allowance	(74)	(383)	(81)	(454)	(800)	(43)
Total Crown	72	345	(79)	272	637	(57)
Freehold	21	316	(93)	144	421	(66)
Gross over-riding	46	144	(68)	162	542	(70)
Total royalties	139	805	(83)	578	1,600	(64)
Per boe	0.89	3.76	(76)	1.58	3.63	(56)

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 June 30 2020	June 30 2019	% Change	Six months ended June 30 2020	June 30 2019	% Change
Total Crown	3.0%	5.5%	(45)	3.9%	4.6%	(15)
Freehold	0.9%	5.0%	(82)	2.1%	3.0%	(30)
Gross over-riding	2.0%	2.3%	(13)	2.4%	3.9%	(38)
Total royalties	5.9%	12.8%	(54)	8.4%	11.5%	(27)

The overall royalty burden for the three months ended June 30, 2020 decreased by 54% to a rate of 5.9% versus 12.8% for the comparative period. Crown royalty rates were lower by 45% due to one of the Company's horizontal oil wells drilled in 2018 coming off its 5% royalty rate and low prices received for the Company's oil and natural gas liquids 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 six months ended June 30, 2020 decreased by 27% to a rate of 8.4% versus 11.5% for the comparative period. The decrease was a result of lower oil and natural gas prices and reduced production volumes.

Transportation expenses

	Three months ended June 30 2020	June 30 2019	% Change	Six months ended June 30 2020	June 30 2019	% Change
Transportation costs	222	395	(44)	562	768	(27)
Per boe	1.42	1.83	(22)	1.54	1.74	(11)

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 80% 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 per boe decreased 22% in the three months ended June 30, 2020 due to lower costs by 44% due to fewer deliveries to main market hubs or terminals. This was partially offset by lower production volumes of 27% versus the comparative period in calculating the cost per boe. For the six months ended June 30, 2020, transportation costs were lower by 27% resulting in a decrease in transportation costs per boe of 11% versus the comparative period.

Operating expenses

	Three months ended			Three months ended		
	June 30 2020	June 30 2019	% Change	June 30 2020	June 30 2019	% Change
Operating costs	2,176	3,092	(30)	5,294	6,396	(17)
Per boe	13.93	14.46	(4)	14.48	14.52	-

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 June 30, 2020 were $13.93 per boe, lower by 4% than the comparative quarter of the prior year, at $14.46 per boe. This decrease reflects a 30% decrease in costs as austere measures were undertaken by the Company related to field operations in light of low oil prices and the shut-in of production volumes. These lower costs were offset by a 27% decrease in production per day resulting in an overall reduction in operating costs per boe. Operating costs for the six months ended June 30, 2020 were lower by 17% versus the comparative period which was offset by lower production volumes of 18% over the same period.

General and administrative expenses

	Three months ended			Six months ended		
	June 30 2020	June 30 2019	% Change	June 30 2020	June 30 2019	% Change
Gross costs	444	762	(42)	1,006	1,357	(26)
Overhead recoveries	(63)	(63)	-	(132)	(120)	10
Total G&A expenses	381	699	(45)	874	1,237	(29)
Per boe	2.44	3.26	(25)	2.39	2.81	(15)

General and administrative costs, net of recoveries, decreased 42% in the three months ended June 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 office staff initiated during the second quarter and the collection of $115,000 under the federal Canada Emergency Wage Subsidy program. Despite a drop in production volumes, these cost cutting measures undertaken by the Company resulted in a reduction in the general and administrative expenses per boe of 25% in the three months ended June 30, 2020 and a 15% reduction in the six months ended June 30, 2020 versus their respective comparative periods.

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 six months ended June 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			Six months ended		
	June 30 2020	June 30 2019	% Change	June 30 2020	June 30 2019	% Change
Stock based compensation	70	192	(64)	209	542	(61)
Per boe	0.45	0.90	(50)	0.57	1.23	(54)

Stock based compensation expense for the three and six months ended June 30, 2020 were lower by 64% and 61%, 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			Six months ended		
	June 30 2020	June 30 2019	% Change	June 30 2020	June 30 2019	% Change
Depletion	1,614	2,564	(37)	3,904	5,142	(24)
Depreciation	1	2	(50)	3	4	(25)
Impairment	-	-	-	22,300	-	100
Total	1,615	2,566	(37)	26,207	5,146	409
Per boe – depletion	10.33	11.98	(14)	10.68	11.67	(8)
Per boe - depreciation	0.01	0.01	-	0.01	0.01	-
Per boe - impairment	-	-	-	61.02	-	100
Total	10.34	11.99	(14)	71.71	11.68	514

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 37% for the three months ended June 30, 2020 is a combination of lower production volumes by 27% versus the comparative period and a lower depletion rate per boe of production of 14% versus the comparative period. The decrease in depletion of 24% for the six months ended June 30, 2020 is a combination of lower production volumes by 18% versus the comparative period and a lower depletion rate per boe of production of 8% 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.

Year	WTI	Edmonton Light	Bow River Medium	Propane	Butane	Pentane	AECO Spot
	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	.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	51	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

Transaction costs

	Three months ended			Six months ended		
	June 30 2020	June 30 2019	% Change	June 30 2020	June 30 2019	% Change
Transaction costs	-	25	(100)	-	110	(100)
Per boe	-	0.12	(100)	-	0.25	(100)

Transactions costs for the six months ended June 30, 2020 were nil versus $110 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			Six months ended		
	June 30 2020	June 30 2019	% Change	June 30 2020	June 30 2019	% Change
Interest on bank debt	230	271	(15)	509	567	(10)
Interest rate swaps	11	-	100	11	-	100
Credit facility fees and costs	19	20	(5)	42	50	(16)
Cash finance costs	260	291	(11)	562	617	(9)
Accretion expense (1)	40	78	(49)	118	177	(33)
Total finance costs	300	369	(19)	680	794	(14)
Per boe – cash finance costs	1.67	1.36	23	1.54	1.40	10
Per boe – accretion expense	0.25	0.36	(31)	0.32	0.40	(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 June 30, 2020 decreased by 11%. 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 period ended June 30, 2020 was 5.45%.

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 5.78% during the period ended June 30, 2020.

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 decreased in the three months ended June 30, 2020 due to a lower inflation rate of 0.99% 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.

Income taxes

	Three months ended			Six months ended		
	June 30 2020	June 30 2019	% Change	June 30 2020	June 30 2019	% Change
Deferred income tax recovery	-	606	(100)	-	1,108	(100)
Per boe	-	2.83	(100)	-	2.52	(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 June 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 June 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 carry-forwards 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			Six months ended		
	June 30 2020	June 30 2019	% Change	June 30 2020	June 30 2019	% Change
Cash flow provided by (used in) operating activities	(304)	847	(136)	854	2,438	(65)
Add back (deduct)						
Decommissioning expenditures	-	-	-	53	-	100
Change in non-cash working capital	387	433	(11)	(308)	906	(134)
Adjusted funds flow (1)	83	1,280	(94)	599	3,344	(82)

(1) See non-GAAP measures

Adjusted funds flow decreased 94% for the three months ended June 30, 2020, primarily due to lower revenues from lower production volumes and realized prices, which was partially offset by realized gains on commodity contracts and reduced operating costs and general and administrative costs.

For the three months ended June 30, 2020, cash flow from operations was negative $0.3 million compared to $0.8 million for the quarter ended June 30, 2019. The decrease of 136% was primarily due to lower revenues from lower prices and production which were partially offset by a change in realized gains on commodity contracts of $0.7 million and reduced operating costs and general and administrative costs.

Net loss

	Three months ended			Six months ended		
	June 30 2020	June 30 2019	% Change	June 30 2020	June 30 2019	% Change
Net earnings (loss)	(2,755)	(658)	318	(25,972)	(1,112)	2,236
Per boe	(17.63)	(3.07)	472	(71.06)	(2.52)	2,720
Per share – basic	(0.24)	(0.06)	300	(2.23)	(0.10)	2,130
Per share – diluted	(0.24)	(0.06)	300	(2.23)	(0.10)	2,130

The Company sustained a net loss of $2.8 million for the three months ended June 30, 2020 compared to a net loss of $0.7 million for the comparative period. The increase in the net loss for the three months ended June 30, 2020 was primarily due to lower revenues and an unrealized loss on commodity contracts versus the comparative period. The increase in the net loss for the six months ended June 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			Six months ended		
Barrel of oil equivalent ($/boe)	June 30 2020	June 30 2019	% Positive (Negative)	June 30 2020	June 30 2019	% Positive (Negative)
Realized sales price	15.05	29.51	(49)	18.86	31.37	(40)
Royalties	(0.89)	(3.76)	76	(1.58)	(3.63)	56
Processing income	0.82	0.74	11	0.70	0.73	(4)
Transportation	(1.42)	(1.83)	22	(1.54)	(1.74)	11
Operating	(13.93)	(14.46)	4	(14.48)	(14.52)	-
Operating netback (2)	(0.37)	10.20	(104)	1.96	12.21	(84)
Realized gain (loss) – commodity contracts	5.01	0.52	863	3.61	(0.16)	2,356
General and administrative	(2.44)	(3.26)	25	(2.39)	(2.81)	15
Transaction costs	-	(0.12)	100	-	(0.25)	100
Cash finance costs	(1.67)	(1.36)	(23)	(1.54)	(1.40)	(10)
Corporate netback (2)	0.53	5.98	(91)	1.64	7.59	(78)
Unrealized gain (loss) – commodity contracts	(7.12)	1.36	(624)	(0.10)	0.68	115
Stock based compensation	(0.45)	(0.90)	50	(0.57)	(1.23)	54
Depletion and depreciation	(10.34)	(11.99)	14	(10.69)	(11.68)	8
Impairment	-	-	-	(61.02)	-	(100)
Accretion	(0.25)	(0.36)	31	(0.32)	(0.40)	20
Deferred income taxes	-	2.83	(100)	-	2.52	(100)
Net earnings (loss)	(17.63)	(3.08)	(472)	(71.06)	(2.52)	(2,720)

(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 June 30, 2020 decreased 91% to $0.53 per boe compared to the prior period. The decrease is primarily due to lower realized sales price for the Company's production of $15.05 per boe in the current period versus $29.51 per boe in the comparative period, The difference in realized sales price was partially offset by realized gains on commodity contracts of $5.01 per boe in the current quarter versus realized gains on commodity contracts of $0.52 in the comparative period, increased processing income per boe and reduced costs per boe for royalties, transportation, operating costs and general and administrative expenses.

SUMMARY OF QUARTERLY RESULTS

Three months ended	Jun 30 2020	Mar 31 2020	Dec 31 2019	Sep 30 2019	Jun 30 2019	Mar 31 2019	Dec 31 2018	Sep 30 2018
Production								
Oil (bbl/d)	320	582	621	641	709	768	668	581
Natural gas liquids (bbl/d)	387	431	494	501	452	473	437	437
Natural gas (mcf/d)	6,058	7,716	7,859	7,487	7,153	7,646	6,745	6,537
Total (boe/d)	1,716	2,299	2,425	2,389	2,353	2,515	2,229	2,107
Financial								
Oil and natural gas sales	2,350	4,542	6,512	5,357	6,318	7,500	4,585	6,297
Adjusted funds flow (1)	83	516	1,271	879	1,280	2,064	511	749
Per share – basic	0.01	0.04	0.11	0.08	0.11	0.19	0.05	0.07
Per share – diluted	0.01	0.04	0.11	0.08	0.11	0.19	0.05	0.07
Net earnings (loss)	(2,755)	(23,217)	(5,527)	(2,129)	(658)	(454)	(2,083)	(1,000)
Per share – basic	(0.24)	(1.99)	(0.48)	(0.18)	(0.06)	(0.04)	(0.20)	(0.10)
Per share - diluted	(0.24)	(1.99)	(0.48)	(0.18)	(0.06)	(0.04)	(0.20)	(0.10)

(1) See non-GAAP measures.

In the second quarter of 2020, production was lower from 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 six months ended June 30, 2020 as net debt was reduced by $0.3 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 $15.0 million at June 30, 2020, down from $15.4 million at December 31, 2019, with the components set out below:

As at	June 30, 2020	Dec. 31, 2019
Trade and other receivables	2,283	2,940
Prepaid expenses and deposits	703	606
Bank debt	(14,365)	(14,807)
Accounts payable and accrued liabilities	(3,214)	(3,675)
Decommissioning obligations	(422)	(422)
Net debt (1)	(15,015)	(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 and prepares for the next review of its credit facility, to be completed by no later than September 15, 2020. The Company monitors net debt as a key component of managing liquidity risk and determining capital resources available to finance future development.

As at June 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 $14.4 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.

The next scheduled review of the credit facility is to be completed no later than September 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 2.0 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 June 30, 2020 was 2.35.

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 June 30, 2020.

	2020	2021	2022	2023	Thereafter
Bank debt	14,365	-	-	-	-
Accounts payable and accrued liabilities	3,214	-	-	-	-
Decommissioning obligations	422	422	422	422	23,883
Gas transportation	115	93	4	-	-
Office lease	54	54	-	-	-
Total	18,170	569	426	422	22,265

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 August 25, 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	559,666	904,166
Vesting in the future in the three months ending:			
December 31, 2020	-	2,500	2,500
June 30, 2021	-	154,501	154,501
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 six months ended June 30, 2020.

RELATED PARTY TRANSACTIONS

There were no related party transactions in the six months ended June 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 0.99% 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 six months ended June 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 six months ended June 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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