Clearview Resources Ltd.

Management Discussion and Analysis (MD&A)

December 31, 2021

2021 HIGHLIGHTS

- Increased production 3% to average 2,119 barrels of oil equivalent per day (“boe/d”) for the year ended December 31, 2021, compared to the prior year, due to a successful reactivation and optimization program;

- Realized sales price for oil increased 81% over the comparative year, to $75.18 per barrel and the realized sales price for natural gas increased 73% over the comparative year to $3.90 per mcf;

- Generated adjusted funds flow of $5.6 million in the year ended December 31, 2021 and cash provided by operating activities of $6.1 million as compared to $2.5 million and $1.8 million, respectively, in the comparative year; and

- Reduced the Company’s net debt to $10.2 million, utilizing adjusted funds flow in excess of capital expenditures and decommissioning expenditures, by repaying bank debt of $3.5 million in 2021.

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The MD&A should be read in conjunction with the Company's audited financial statements and accompanying notes for the periods ended December 31, 2021 and December 31, 2020. The audited financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board ("IASB"). All dollar amounts in the tables are expressed in thousands of Canadian dollars ($000's), except per unit amounts, and unless otherwise noted. The MD&A has been prepared and approved by the Board of Directors as of April 26, 2022.

Refer to page 30 for information about Non-IFRS Measures, page 33 for information on forward-looking statements and page 34 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. The Company is a reporting issuer with additional information about the Company 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	5,894	87%	Yes
	Pembina	Liquids rich natural gas	1,457	80%	Yes
	Wilson Creek	Light oil and liquids rich natural gas	3,685	60%	Yes
	Windfall	Light oil	6,165	100.0%	Yes
	Niton	Light oil	1,395	96%	Yes
	Garrington	Light oil and liquids rich natural gas	1,561	94%	Yes
	Caribou	Light oil	491	70.0%	Yes
Other	Bantry	Medium oil	216	40.0%	No
	Carstairs (Unit)	Liquids rich natural gas	697	17.0%	No
	Lindale (Unit)	Light oil with associated natural gas and liquids	101	10.6%	No
	Miscellaneous	Various	107	Various	Mixed
Total			21,769		

[1] mboe of total proved plus probable reserves at December 31, 2021 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 operating structure;
- maintain an appropriate debt versus equity capital structure;
- build the Company's production base to fund the field capital program from internally generated funds;
- maintain strong lending values to support the Company's credit facility;
- maintain a current licensee liability rating of 2.0 or greater, providing the Company with the ability to transact on further acquisition opportunities; and
- evaluate non-core assets, for potential disposition, to fund the capital program.

SELECTED ANNUAL INFORMATION

	Three months ended		Years ended		
	Dec. 31 2021	Dec. 31 2020	Dec. 31 2021	Dec. 31 2020	Dec. 31 2019
Oil and natural gas sales	8,918	4,870	30,364	16,133	25,687
Adjusted funds flow (1)	1,797	957	5,573	2,487	5,494
Per share – basic	0.15	0.08	0.48	0.21	0.48
Per share – diluted	0.14	0.08	0.44	0.21	0.48
Cash provided by operating activities	2,065	55	6,130	1,783	4,980
Per share – basic	0.18	-	0.53	0.15	0.43
Per share - diluted	0.16	-	0.48	0.15	0.43
Net earnings (loss)	10,512	16,891	5,212	(10,842)	(8,768)
Per share – basic	0.90	1.45	0.45	(0.93)	(0.76)
Per share – diluted	0.82	1.45	0.42	(0.93)	(0.76)
Total assets			73,137	70,498	80,038
Total long term liabilities			24,655	26,387	23,420
Net debt (1)			10,193	13,235	15,358
Net capital expenditures (1)	640	54	2,108	376	1,955

(1) Non-IFRS measure or ratio that does not have any standardized meaning as prescribed by International Financial Reporting Standards and therefore may not be comparable with the calculations of similar measures or ratios of other entities. See “Non-IFRS Measures” contained within this MD&A.

For the year ended December 31, 2021, the Company’s oil and natural gas sales increased to $30.4 million due to higher realized sales prices for all its production while production remained very steady year over year with a 3% increase. Adjusted funds flow was $5.6 million while cash provided by operating activities was $6.1 million for the year ended December 31, 2021. Long term liabilities decreased in the year ended December 31, 2021 due to decommissioning operations undertaken during 2021 to abandon 29 gross (13.2 net) wells and a higher discount rate positively affecting the discounting of decommissioning obligations. Net debt was reduced over the twelve months ended December 31, 2021 as adjusted funds flow in excess of net capital expenditures was applied against bank debt. Net earnings for 2021 were $5.2 million compared to a net loss in the prior year of $10.8 million. The increase in 2021 was primarily due to much higher revenues as a result of higher commodity prices and an impairment reversal of $8.3 million in the fourth quarter of 2021.

In the year ended December 31, 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 $9.6 million was partially offset by an increase in realized gains on risk management contracts of $1.1 million, lower royalties of $1.9 million, lower operating costs of $3.0 million, lower transportation costs of $0.2 million and lower general and administrative expenses of $ 0.7 million, resulting in adjusted funds flow being lower by $3.0 million versus the comparative year. Cash provided by operating activities was reduced due to the lower adjusted funds flow and a negative change in operating working capital of $0.6 million. The net loss for the year ended December 31, 2020 increased to $10.8 million, an increase of $2.1 million primarily due to lower adjusted funds flow by $3.0 million and an increase in impairment expense of $0.6 million. These reductions were partially offset by lower depletion expense of $2.0 million. Net debt was reduced by $2.1 million in 2020 as adjusted funds flow in excess of capital expenditures was applied against working capital and bank debt.

Capital expenditures

	Three months ended			Year ended		
	Dec. 31 2021	Dec.31 2020	% Change	Dec. 31 2021	Dec. 31 2020	% Change
Land	22	-	100	143	3	4,667
Drilling, completions, equipping	338	11	2,973	1,288	311	314
Facilities	307	69	345	676	322	110
Other	(27)	(25)	8	1	2	(50)
Capital expenditures (1)	640	55	1,064	2,108	638	230
Disposition of properties	-	-	-	-	-	-
Acquisition of properties	-	(1)	(100)	-	(262)	(100)
Net capital expenditures (1)	640	54	1,085	2,108	376	461

(1) Non-IFRS measure or ratio that does not have any standardized meaning as prescribed by International Financial Reporting Standards and therefore may not be comparable with the calculations of similar measures or ratios of other entities. See “Non-IFRS Measures” contained within this MD&A.

The Company spent approximately 38% of its adjusted funds flow on capital expenditures in the year ended December 31, 2021. The capital expenditures incurred were primarily for facility upgrades and well workovers and optimizations as part of an approved well reactivation/optimization program. The optimization program completed in 2021 resulted in annualized production additions of approximately 190 boe/d and offset the Company’s natural production decline rate of approximately 10% to 12%, annually.

During 2021, the Company acquired lands in the Jarvie area of Alberta for $132 thousand.

Production

Production is summarized in the following table:

	Three months ended			Year ended		
	Dec. 31 2021	Dec. 31 2020	% Change	Dec. 31 2021	Dec. 31 2020	% Change
Oil – bbl/d	433	487	(11)	462	480	(4)
Natural gas liquids – bbl/d	487	345	41	464	393	18
Total liquids – bbl/d	920	832	11	926	873	6
Natural gas – mcf/d	6,755	7,443	(9)	7,158	7,091	1
Total – boe/d	2,045	2,072	(1)	2,119	2,055	3

Production for the quarter ended December 31, 2021, decreased by 1% versus the respective comparative period. The decrease in production was due to lower oil production of 11% as a result of natural declines and having not drilled a well in the past three years and lower natural gas production due to natural declines and reduced production due to extremely cold weather late in 2021. Natural gas liquids, generally associated with natural gas production, increased 41% for the quarter ended December 31, 2021 versus the comparative period. The increase was primarily due to changing natural gas processing for a portion of the Company’s natural gas production. The current facility extracts greater ethane volumes while processing the natural gas.

For the year ended December 31, 2021, overall production increased by 3% due to the Company’s well reactivation/optimization program undertaken in the first and third quarters of the year, predominantly focused on liquids rich natural gas projects. This program resulted in increased production volumes to largely offset the Company’s natural production decline rate of approximately 10% to 12%, annually. Natural gas liquids increased 18% versus the prior year, primarily due to a change in natural gas processing, for a portion of the Company’s natural gas production, which extracts primarily greater ethane volumes while processing the natural gas. The comparative period of 2020 was negatively affected by shut-in volumes for a period of time in the second quarter due to the COVID-19 pandemic.

Minimal capital expenditures have been incurred on workovers or optimization projects in the past two years as the Company has chosen to direct the majority of its adjusted funds flow towards the repayment of net debt.

Clearview's production portfolio for the year ended December 31, 2021 was weighted 22% to oil, 22% to natural gas liquids and 56% to natural gas. For the year ended December 31, 2020 the production mix was weighted 23% to oil, 19% to natural gas liquids and 58% to natural gas. The change in production mix of the Company year over year has primarily been influenced by the change in natural gas processing.

Benchmark prices and economic parameters

	Three months ended			Year ended		
	Dec. 31 2021	Dec. 31 2020	% Change	Dec. 31 2021	Dec. 31 2020	% Change
Oil – West Texas Intermediate ("WTI") (US $/bbl)	77.17	42.67	81	67.96	39.39	73
Oil – Edmonton Par ($/bbl)	93.30	50.09	86	80.29	45.30	77
Differential – Light oil ($/bbl) (1)	(3.87)	(5.45)	(29)	(4.85)	(7.34)	(34)
NGLs - Pentane ($/bbl)	100.14	55.88	79	85.93	49.85	72
NGLs – Butane ($/bbl)	81.84	19.33	323	51.74	21.85	137
NGLs – Propane ($/bbl)	58.44	16.33	258	43.39	16.35	165
Natural gas – AECO ($/mcf)	4.65	2.56	82	3.62	2.22	63
Exchange rate – US$/Cdn$	0.794	0.768	3	0.798	0.746	7

(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 December 31, 2021 increased 81% from an average of US $42.67 per barrel in 2020 to US $77.17 per barrel in 2021. This significant increase in WTI was a result of global economies beginning to open up and recover from the severe collapse in economic activity associated with the COVID-19 pandemic in the prior year. Canadian oil prices increased by 86% in the three months ended December 31, 2021, compared to the same quarter in 2020, as the Canadian dollar strengthened by 3%, weakening Canadian prices, and the light oil differential narrowed by 29% over the same comparative quarter on top of the increase in WTI.

Benchmark oil prices for the year ended December 31, increased from an average of US $39.39 per barrel in 2020 to US $67.96 per barrel in 2021, resulting in a 73% increase. Canadian oil prices increased by 77% in the year ended December 31, 2021 compared to the same period in 2020 as the Canadian light oil differential or discount narrowed by 34% over the same comparative period on top of the increase in WTI.

Pentane prices increased over the three months and year ended December 31, 2021 in a very similar manner to WTI pricing and Canadian light oil prices, with increases of 79% and 72%, respectively, versus the comparative periods of 2020.

Butane prices averaged $81.84 per barrel for the quarter ended December 31, 2021, an increase of 323% from the same quarter of 2020. Butane prices averaged $51.74 per barrel for the year ended December 31, 2021, an increase of 137% from the same period of 2020. The recovery in butane prices over 2021 versus the same period in 2020 is largely due to increased demand for the product with the recovery of the North American economy and the rise in WTI prices.

Propane prices averaged $58.44 per barrel for the quarter ended December 31, 2021, an increase of 258% compared to the same quarter of 2020. Propane prices averaged $43.39 per barrel for the year ended December 31, 2021, an increase of 165% from the same period of 2020. Propane prices increased due to continued higher US exports to keep the market in balance with Canadian propane prices increasing as exports off the west coast of Canada continue to increase.

AECO natural gas prices averaged $4.65 per mcf for the three months ended December 31, 2021, an increase of 82% as compared to the same quarter of 2020. For the year ended December 31, 2021, AECO natural gas prices are higher by 63% than the comparative period of 2020. AECO pricing was very strong throughout 2021 due to the low supply of natural gas going into storage in Alberta and the continued build out of export capacity from Western Canada.

Realized sales prices

	Three months ended			Year ended		
	Dec. 31 2021	Dec. 31 2020	% Change	Dec. 31 2021	Dec. 31 2020	% Change
Oil – $/bbl	87.55	45.41	93	75.18	41.50	81
NGLs – $/bbl	52.61	28.20	87	44.23	20.72	113
Natural gas – $/mcf	4.95	2.84	74	3.90	2.26	73
Total – $/boe	47.39	25.55	85	39.26	21.45	83

Realized prices primarily vary from the benchmark prices due to quality differences, including differences for density and sulphur content. The differential can vary considerably from quarter to quarter. During the three months ended December 31, 2021, the Company's realized oil price was higher by 93% than the comparative quarter as a result of an 86% increase in Edmonton Par benchmark pricing. The increase in realized oil price of 81% for the year ended December 31, 2021 is consistent with the 77% increase in the Edmonton Par benchmark pricing over the prior year.

Natural gas liquids prices were higher by 87% in the fourth quarter of 2021 and higher by 113% for the current year versus the comparative periods of 2020. This increase was primarily due to higher prices received for all the Company's ethane, propane, butane and pentane production as a result of the increase in WTI.

The Company's realized price for natural gas was higher by 74% for the three months ended December 31, 2021. This compares to an 82% 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. For the year ended December 31, 2021, the realized natural gas price increased by 73%, compared to the prior year, consistent with the increase in AECO of 63% over the same period. A portion of the Company's natural gas production which is sold in Alberta received a higher price adjustment, non AECO based, in 2021 than in 2020 which had a positive effect on the Company's premium to AECO in 2021.

On a boe basis, the Company's realized price was 85% higher for the three months ended December 31, 2021, than the comparative period, due to the higher prices received for all its production. The Company's realized price per boe increased 83% for the year ended December 31, 2021, due to the much higher Canadian oil prices and the prices received for the Company's natural gas liquids, versus the comparative period.

Revenues

Oil and natural gas sales

	Three months ended			Year ended		
	Dec. 31 2021	Dec. 31 2020	% Change	Dec. 31 2021	Dec. 31 2020	% Change
Oil	3,489	2,034	72	12,690	7,292	74
Natural gas liquids	2,354	895	163	7,478	2,983	151
Total liquids	5,843	2,929	99	20,168	10,275	96
Natural gas	3,075	1,941	58	10,196	5,858	74
Total sales	8,918	4,870	83	30,364	16,133	88
Per boe	47.39	25.55	85	39.26	21.45	83

Crude oil sales increased 72% in the three months ended December 31, 2021 as a decrease in oil production volumes of 11% was offset by an increase of 93% in realized oil prices.

Natural gas liquids revenues were higher by 163% in the quarter ended December 31, 2021 as production increases of 41% were compounded by higher realized natural gas liquids prices by 87%.

Natural gas revenue increased 58% in the quarter ended December 31, 2021 as lower production volumes of 9% were sold for a 74% higher realized natural gas price than in the comparative quarter of 2020.

The 83% increase in oil and gas sales for the three months ended December 31, 2021 is due to lower production volumes by 1% being sold in the quarter at an average higher price received per boe by 85% than the comparative quarter of 2020. The 88% increase in oil and gas sales for the year ended December 31, 2021 is due to both higher production volumes being sold in the year by 3% and an average higher price received per boe of 83% than the prior year.

Revenues from the sale of oil, natural gas and natural gas liquids are normally collected on the 25th day of the month following production. Clearview 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, Garrington, 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			Year ended		
	Dec. 31 2021	Dec. 31 2020	% Change	Dec. 31 2021	Dec. 31 2020	% Change
Processing income	128	119	8	472	518	(9)
Per boe	0.68	0.62	10	0.61	0.69	(12)

Processing income increased slightly to $128 thousand for the three months ended December 31, 2021, an 8% increase from the comparative quarter ended December 31, 2020. For the year ended December 31, 2021, processing income decreased 9% versus the comparative period of 2020. 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 commodity price contracts outstanding at December 31, 2021.

Commencement Date	Expiry Date	Units	Volume	Underlying Commodity	Fixed Price
January 1, 2022	October 31, 2022	GJ/day	3,000	AECO 5A - Financial	$2.75
January 1, 2022	June 30, 2022	Bbls/day	250	Edmonton Par - Financial	$75.95
July 1, 2022	September 30, 2022	Bbls/day	100	Edmonton Par - Financial	$80.30
July 1, 2022	September 30, 2022	Bbls/day	150	Edmonton Par - Financial	$71.90 - $85.90**

** The Company entered into a costless collar contract whereby it will realize a minimum price of $71.90 per barrel and a maximum price of $85.90 per barrel for the term of the contract.

The fair value of the financial commodity and interest rate contracts outstanding as at December 31, 2021 is estimated to be a liability of $1.1 million. At December 31, 2020, the fair value of the financial contracts outstanding was a liability of $0.4 million. The fair value of these contracts is based on the forward prices and market values provided by independent sources and represents the asset that would have been received from the counterparties to settle the contracts at the end of the reporting period. Due to the volatility of commodity prices, interest rates and foreign exchange rates, actual amounts may differ from these estimates.

For the year ended December 31, 2021, the Company recognized an unrealized loss of $0.7 million on its outstanding commodity contracts versus an unrealized loss of $0.2 million in the prior year ended December 31, 2020. In the three months ended December 31, 2021, Clearview recorded an unrealized gain on commodity contracts of $2.0 million as compared to an unrealized gain of $0.3 million in the three months ended December 31, 2020. The unrealized gain or loss in the three months and year ended December 31, 2021 is the difference between the fair values of the commodity contracts at December 31, 2021 and the fair values of outstanding commodity contracts at the respective prior reporting periods.

For the year ended December 31, 2021, the Company had a realized loss on commodity contracts of $4.5 million versus a realized gain in the prior year of $1.2 million. During the three months ended December 31, 2021, the Company recorded a realized loss of $1.6 million versus a realized loss of $79 thousand in the comparative quarter of 2020.

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

Royalties

Amount	Three months ended Dec. 31 2021	Dec. 31 2020	% Change	Year ended Dec. 31 2021	Dec. 31 2020	% Change
Crown – oil	410	64	541	1,034	303	241
Crown – natural gas liquids	658	236	179	2,013	824	144
Crown – natural gas	268	161	66	745	432	72
Gas cost allowance	(131)	(398)	(67)	(851)	(1,184)	(28)
Total Crown	1,205	63	1,813	2,941	375	684
Freehold	239	(63)	(479)	647	154	320
Gross over-riding	211	98	115	678	355	91
Total royalties	1,655	98	1,589	4,266	884	383
Per boe	8.79	0.51	1,624	5.52	1.18	368

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 majority of the Company's production is on Crown lands.

The Company reviews its entitlement to gas cost allowance at each reporting period. The timeframe for the royalty regulatory process, the complexity of the calculation and the uncertainty (particularly for non-operated properties from which the Company takes its revenue in kind) as to whether the Company will be eligible to actually receive the allowance are factors considered in determining the estimate and the amount to record for that period.

Royalty rate	Three months ended Dec. 31 2021	Dec. 31 2020	% Change	Year ended Dec. 31 2021	Dec. 31 2020	% Change
Total Crown	13.4%	1.3%	931	9.7%	2.3%	322
Freehold	2.7%	(1.3)%	(308)	2.2%	1.0%	120
Gross over-riding	2.4%	2.0%	20	2.2%	2.2%	-
Total royalties	18.5%	2.0%	825	14.1%	5.5%	156

The overall royalty burden for the three months ended December 31, 2021 increased by 825% to a rate of 18.5% versus 2.0% for the comparative period. Crown royalty rates were higher by 931% primarily due to much higher prices received for all the Company's production. Crown royalties on natural gas and natural gas liquids production were much higher than gas cost allowance in 2021, whereas in 2020 the gas cost allowance offset the Crown royalty charges for natural gas and natural gas liquids. Freehold royalties and gross over-riding royalties increased as well due to higher realized prices.

The overall royalty burden for the year ended December 31, 2021 increased by 156% to a rate of 14.1% versus 5.5% for the comparative period. The increase was a result of higher realized sales prices for the Company's oil, natural gas and natural gas liquids production volumes.

Transportation expenses

	Three months ended Dec. 31 2021	Dec. 31 2020	% Change	Year ended Dec. 31 2021	Dec. 31 2020	% Change
Transportation costs	291	297	(2)	1,307	1,178	11
Per boe	1.55	1.56	(1)	1.69	1.57	8

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. During 2021, the Company had 75% 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 decreased 2% in the three months ended December 31, 2021. Transportation expense per boe for the three months ended December 31, 2021 decreased 1% versus the comparative quarter of 2020.

For the year ended December 31, 2021, transportation costs were higher by 11% versus the comparative period of 2020. This increase is due to higher cost of services as vendors eliminated the discounts which were negotiated in the prior year during the pandemic price collapse and the addition of charges for higher fuel costs to truck oil production. Transportation expense per boe for the year ended December 31, 2021 increased 8% versus the comparative year of 2020.

Operating expenses

	Three months ended			Year ended		
	Dec. 31 2021	Dec. 31 2020	% Change	Dec. 31 2021	Dec. 31 2020	% Change
Operating costs	3,167	2,328	36	12,217	10,113	21
Per boe	16.83	12.21	38	15.80	13.44	18

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 per boe for the three months ended December 31, 2021 were $16.83 per boe, higher by 38% than the comparative quarter of the prior year, at $12.21 per boe. This increase reflects a 36% increase in absolute operating costs compounded by a 1% decrease in production per day. The costs of field services have increased with the increase in commodity prices. In addition, the Company has experienced higher processing fees from third party plant owners and has increased its repairs and maintenance spending to increase production in the current higher price environment.

Operating costs per boe for the year ended December 31, 2021 were $15.80 per boe, higher by 18% than the comparative period of the prior year, at $13.44 per boe. This increase reflects a 21% increase in absolute operating costs due to an increase in the cost of field services, higher processing fees from third party plant owners and an increase in repairs and maintenance spending to increase production in the current higher price environment. The higher costs were partially offset by a 3% increase in production per day.

General and administrative expenses

	Three months ended			Year ended		
	Dec. 31 2021	Dec. 31 2020	% Change	Dec. 31 2021	Dec. 31 2020	% Change
Gross costs	633	486	30	2,386	1,833	30
Overhead recoveries	(50)	(45)	11	(190)	(222)	(14)
Total G&A expenses	583	441	32	2,196	1,611	36
Per boe	3.10	2.31	34	2.84	2.14	33

General and administrative costs, net of recoveries, increased 32% and 36%, respectively, in the quarter ended and year ended December 31, 2021, versus the comparative periods of 2020. The increase was primarily as a result of an increase in personnel costs associated with the reinstatement of salaries which had been reduced for nine months during 2020 and early 2021, bonus compensation to non-executive personnel, the reinstatement of a portion of the directors fees, higher professional fees and executive transition costs upon the resignation of an officer. These increased costs were partially offset by lower office lease costs in the first and second quarter of 2021.

The higher costs were compounded by a 1% decrease in production volumes for the quarter resulting in a 34% increase in general and administrative expenses per boe for the three months ended December 31, 2021 versus the comparative quarter.

The higher costs of 36% in the year ended December 31, 2021 were offset by a 3% increase in production volumes for the quarter resulting in a 33% increase in general and administrative expenses per boe for the year ended December 31, 2021 versus the comparative period. For the year ended December 31, 2020, general and administrative costs, net of recoveries, were lower than normal due to cost cutting initiatives. These initiatives primarily included the elimination of contract office positions, the elimination of directors' fees, reduced salaries for staff and management initiated during the second quarter and the receipt of $0.2 million for the year ended December 31, 2020, under the federal Canada Emergency Wage Subsidy program.

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 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.

	Three months ended			Year ended		
	Dec. 31 2021	Dec. 31 2020	% Change	Dec. 31 2021	Dec. 31 2020	% Change
Stock based compensation	50	123	(59)	203	378	(46)
Per boe	0.27	0.65	(58)	0.26	0.50	(48)

Stock based compensation expense for the three months ended December 31, 2021 and year ended December 31, 2021 was lower by 59% and 46%, respectively, versus the comparative periods. The decrease in expense is primarily due to graded vesting which records more expense in the earlier years after granting.

During the year ended December 31, 2021, employees who left the Company forfeited 56,000 options and the Company granted 50,000 options to an officer at an exercise price of $3.96 per share under option late in 2021.

The fair value of the options at the date of measurement was determined based on a Black-Scholes calculation with the following inputs and outcomes:

	Year ended December 31, 2021	Year ended December 31, 2020
	Inputs	**Inputs**
Exercise price	**$3.96**	**$1.25**
Volatility	**98%**	**83%**
Expected option life	**6.5 years**	**6.5 years**
Dividend	**$nil**	**$nil**
Risk-free interest rate	**1.37%**	**0.51%**
Estimated cost per voting common share under option	**$3.98**	**$1.11**
Total estimated cost to be amortized over the vesting period	**$199**	**$357**

Depletion and depreciation

	Three months ended			Year ended		
	Dec. 31 2021	Dec. 31 2020	% Change	Dec. 31 2021	Dec. 31 2020	% Change
Depletion	1,748	2,057	(15)	7,912	8,061	(2)
Depreciation	1	1	-	5	6	(17)
Total	1,749	2,058	(15)	7,917	8,067	(2)
Per boe – depletion	9.29	10.79	(14)	10.23	10.72	(5)
Per boe - depreciation	-	-	-	0.01	0.01	-
Total	9.29	10.79	(14)	10.24	10.73	(5)

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 for the three months ended December 31, 2021 is primarily due to lower production volumes, the impairment expense taken in the prior year and the addition of proved plus probable reserves at December 31, 2021. Production decreased 1% and the depletion rate per boe decreased by 14% resulting in an overall reduction in depletion expense of 15% versus the comparative quarter of 2020. Depletion for the year ended December 31, 2021 was 2% lower than the prior year. This decrease reflects higher production volumes of 3% and a lower depletion rate per boe of 5% in 2021 than the comparative year.

Impairment (reversal)

	Three months ended			Year ended		
	Dec. 31 2021	Dec. 31 2020	% Change	Dec. 31 2021	Dec. 31 2020	% Change
Impairment (reversal)	(8,300)	(18,000)	(54)	(8,300)	4,300	(293)
Per boe	(44.11)	(94.42)	(53)	(10.73)	5.72	(288)

At December 31, 2021, Clearview identified indicators of impairment reversal, primarily due to the increase in commodity prices and significant positive technical revisions due to reduced decline rates and an optimization capital program undertaken during 2021. As a result, the Company completed an impairment reversal test on two of its three CGU's and determined that the net recoverable amount exceeded the carrying values for the Central Alberta Gas CGU and Central Alberta Oil CGU.

The estimated net recoverable amount was based on before-tax discount rates specific to the underlying reserve category as determined by the Company's independent third-party reserve evaluator at December 31, 2021 and risk profile of each CGU, net of decommissioning obligations. The discount rates used in the valuation was an average of 15% to 20%. The impairment reversal tests, using the fair value less costs to sell method, indicated the Central Alberta Gas CGU's recoverable amount was higher than its carrying value resulting in an impairment reversal of $5.8 million and that the Central Alberta Oil CGU's recoverable amount was higher than its carrying value resulting in an impairment reversal of $2.5 million, both recorded as a reversal of impairment in earnings, for a total reversal of impairment of $8.3 million.

The table below details the pricing used in estimating the recoverable amounts at December 31, 2021.

	WTI	Edmonton Light	Bow River Medium	Propane	Butane	Pentane	AECO Spot
Year	US/bbl	Cdn/bbl	Cdn/bbl	Cdn/bbl	Cdn/bbl	Cdn/bbl	Cdn/bbl
2022	72.83	86.82	75.22	43.38	57.49	91.85	3.56
2023	68.78	80.73	69.92	35.92	50.17	85.53	3.21
2024	66.76	78.01	67.26	34.62	48.53	82.98	3.05
2025	68.09	79.57	68.60	35.31	49.50	84.63	3.11
2026	69.45	81.16	69.98	36.02	50.49	86.33	3.17
2027	70.84	82.78	71.37	36.74	51.50	88.05	3.23
2028	72.26	84.44	72.80	37.47	52.53	89.82	3.30
2029	73.70	86.13	74.25	38.22	53.58	91.61	3.36
2030	75.18	87.85	75.49	38.99	54.65	93.44	3.43
2031	76.68	89.61	77.00	39.77	55.74	95.32	3.50
2032	78.21	91.40	78.54	40.56	56.86	97.22	3.57
2033	79.78	93.23	80.11	41.37	57.99	99.17	3.64
2034	81.37	95.09	81.72	42.20	59.15	101.15	3.71
2035	83.00	96.99	83.35	43.05	60.34	103.17	3.79
2036	84.66	98.93	85.02	43.91	61.54	105.24	3.86
2037+	+2.0%/yr	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.

At December 31, 2020, Clearview identified indicators of impairment reversal, primarily due to the increase in commodity prices and significant positive technical revisions, due to reduced decline rates and reduced operating costs, since the last impairment test performed on March 31, 2020. As a result, the Company completed an impairment reversal test on two of its three CGU's and determined that the net recoverable amount exceeded the carrying values for the Central Alberta Gas CGU and Central Alberta Oil CGU.

The estimated net recoverable amount was based on before-tax discount rates specific to the underlying reserve category as determined by the Company's independent third-party reserve evaluator at December 31, 2020 and risk profile of each CGU, net of decommissioning obligations. The discount rate used in the valuation was an average of 15%. The impairment reversal tests, using the fair value less costs to sell method, indicated the Central Alberta Gas CGU's recoverable amount was higher than its carrying value resulting in an impairment reversal of $10.9 million and that the Central Alberta Oil CGU's recoverable amount was higher than its carrying value resulting in an impairment reversal of $7.7 million, both recorded as a reversal of impairment in earnings, for a total reversal of impairment of $18.6 million.

At December 31, 2020, Clearview identified indicators of impairment, primarily due to continued production declines with no capital spending directed to its Southern Alberta Oil CGU. As a result, the Company completed an impairment test on the CGU and determined that the net carrying amount exceeded the net recoverable amount for the Southern Alberta Oil CGU.

The estimated net recoverable amount was based on before-tax discount rates specific to the underlying reserve category as determined by the Company's independent third-party reserve evaluator at December 31, 2020 and risk profile of the CGU, net of decommissioning obligations. The discount rate used in the valuation was an average of 15%. The impairment test, using the fair value less costs to sell method, indicated the Southern Alberta Oil CGU's recoverable amount was lower than its carrying value resulting in an impairment of $0.6 million being recorded in earnings.

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

Year	WTI US/bbl	Edmonton Light Cdn/bbl	Bow River Medium Cdn/bbl	Propane Cdn/bbl	Butane Cdn/bbl	Pentane Cdn/bbl	AECO Spot Cdn/bbl
2021	47.17	55.76	45.36	18.18	26.36	59.24	2.78
2022	50.17	59.89	48.96	21.91	32.85	63.19	2.70
2023	53.17	63.48	52.91	24.57	39.20	67.34	2.61
2024	54.97	65.76	54.95	25.47	40.65	69.77	2.65
2025	56.07	67.13	56.05	26.00	41.50	71.18	2.70
2026	57.19	68.53	57.16	26.54	42.36	72.61	2.76
2027	58.34	69.95	58.30	27.09	43.24	74.07	2.81
2028	59.50	71.40	59.47	27.65	44.14	75.56	2.87
2029	60.69	72.88	60.66	28.23	45.06	77.08	2.92
2030	61.91	74.34	61.87	28.79	45.96	78.62	2.98
2031	63.15	75.83	63.10	29.37	46.88	80.2	3.04
2032	64.41	77.34	64.37	29.95	47.82	81.80	3.10
2033	65.70	78.89	65.65	30.55	48.77	83.44	3.16
2034	67.01	80.47	66.97	31.16	49.75	85.10	3.23
2035	68.35	82.08	68.31	31.79	50.74	86.81	3.29
2036+	+2.0%/yr	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.	+2.0%/yr.

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 three 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 as determined by the Company's independent third party evaluator as of December 31, 2019 and updated by the Company to March 31, 2020 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 US/bbl	Edmonton Light Cdn/bbl	Bow River Medium Cdn/bbl	Propane Cdn/bbl	Butane Cdn/bbl	Pentane Cdn/bbl	AECO Spot 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.

As a result of the impairment tests completed during 2020, the Company recognized a net impairment expense of $4.3 million.

Other costs (income)

	Three months ended			Year ended		
	Dec. 31 2021	Dec. 31 2020	% Change	Dec. 31 2021	Dec. 31 2020	% Change
Bad debt provision (recovery)	(152)	256	(159)	(170)	256	(166)
Royalty holder settlement	(565)	-	100	(565)	-	100
Earned non-refundable deposit	-	-	-	(50)	-	100
Crown charges	387	-	100	387	-	100
Site rehabilitation program	(301)	(51)	490	(604)	(51)	1,084
Total	(631)	205	(408)	(1,002)	205	(589)
Per boe	(3.35)	1.07	(413)	(1.30)	0.27	(580)

In 2021, Clearview collected on numerous receivables for which a provision had been recorded in the prior year while also reducing the provision recorded in the prior year for other receivables which are now considered to be collectible. Collection is considered more likely due to the improved financial position of its joint venture partners with the recovery of commodity prices in 2021. At December 31, 2021, the Company recorded a provision of $20 thousand as an allowance for doubtful accounts.

In 2021, the Company agreed to a settlement of $0.6 million with a freehold royalty owner for the double payment of royalties for the period April 2012 to December 31, 2020.

During the year, the Company earned $50 thousand as a non-refundable deposit due to a potential acquirer of a property being unable to close the acquisition.

In 2021, the Company incurred an expense of $0.4 million related to unpaid Crown charges billed by Crown for the first quarter of 2017 which had not been paid by the vendor, the receiver of a bankrupt company, related to oil and gas producing properties purchased by the Company in the first quarter of 2017.

During the year ended December 31, 2021, the Company incurred $0.9 million in abandoning 29 gross (13.2 net) wells, represented by $0.3 million funded from cash flow from operations and $0.6 million (for the year ended December 31, 2020 - $51 thousand) from eligible government grants from the Site Rehabilitation Program of the Government of Alberta.

Finance costs

	Three months ended			Year ended		
	Dec. 31 2021	Dec. 31 2020	% Change	Dec. 31 2021	Dec. 31 2020	% Change
Interest - bank debt	208	243	(14)	946	963	(2)
Interest rate swaps	-	12	(100)	9	36	(75)
Interest - convertible debentures	31	11	182	126	11	1,045
Credit facility fees and costs	56	318	(82)	67	360	(81)
Cash finance costs (1)	295	584	(49)	1,148	1,370	(16)
Accretion expense	55	89	(38)	462	287	61
Total finance costs	350	673	(48)	1,610	1,657	(3)
Per boe – cash finance costs (1)	1.57	3.06	(49)	1.48	1.82	(19)
Per boe – accretion expense	0.29	0.47	(38)	0.60	0.38	58

(1) Non-IFRS measure or ratio that does not have any standardized meaning as prescribed by International Financial Reporting Standards and therefore may not be comparable with the calculations of similar measures or ratios of other entities. See “Non-IFRS Measures” contained within this MD&A.

Cash finance costs include interest on bank debt and lender fees, realized gains or losses on interest rate swaps and interest on convertible debentures.

Interest on bank debt in the three months ended and year ended December 31, 2021 decreased by 14% and 2%, respectively, versus the comparative period. The decrease was due a lower credit spread pursuant to the Company's lending agreement and outstanding bank debt being reduced by adjusted funds flow in excess of capital expenditures.

As of December 31, 2021, the Company is paying 6.70% (lender's prime rate of 2.45% plus a credit spread of 4.25%) on prime based loans and the EDC facility. The Company also has the option of borrowing using the lender's guaranteed notes which are subject to a stamping fee plus the guaranteed note rate for 30, 60, 90 and 180 day terms. Effective December 31, 2021, the Company is paying 5.70% (CDOR of 0.45% plus a stamping fee of 5.25%) on guaranteed notes.

The interest rates applicable to drawings under the lending agreement are based on a pricing margin grid and can change quarterly as a result of the ratio of all outstanding indebtedness to annualized quarterly funds flows as calculated in accordance with the agreement governing the facility ("Debt to Funds Flow"). Annualized quarterly funds flow is defined as earnings before depletion and depreciation, stock based compensation, accretion of decommissioning obligations and debenture discounts, unrealized gains or losses on commodity contracts, gains or losses on dispositions, non cash other costs (income) and deferred income taxes.

The interest rate on the convertible debentures is 10%, payable quarterly in arrears on March 31, June 30, September 30 and December 31 of each year. In 2021, the debentures were outstanding for the full year whereas in 2020 the debentures were outstanding for the month of December only.

In addition, the Company paid its lender a standby fee on the difference between the credit facility of $18.5 million and the combined prime-based loans and guaranteed notes borrowings for eleven months of the year. In 2021, the standby fee was calculated based on the combined credit facilities limit of $21.25 million at the beginning of the year which was reduced to $17.25 million in the fourth quarter and then $15.0 million upon renewal of the credit facilities at the end of November 2021.

Credit facility fees and costs in the three months and year ended December 31, 2021 are lower by 82% and 81%, respectively. In the fourth quarter of 2021, the Company's lender completed its credit review with much lower credit facility fees due to the improved environment for the industry. In the fourth quarter of 2020, credit facility fees and costs include legal fees associated with the review, renewal fees for the credit facilities, a consultant fee related to the EDC guarantee and an annual 1.8% fee for the guaranteed facility.

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 47 years due to the long-term nature of certain assets. Accretion expense decreased in the three months and year ended December 31, 2021 due to the extension of the average abandonment dates.

Income taxes

	Three months ended			Year ended		
	Dec. 31 2021	Dec. 31 2020	% Change	Dec. 31 2021	Dec. 31 2020	% Change
Deferred income tax recovery	-	16	(100)	-	16	(100)
Per boe	-	0.08	(100)	-	0.02	(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 December 31, 2021. Therefore, no deferred income tax expense or recovery has been recorded in earnings in the current period. The deferred tax recovery of $16 thousand for the year ended December 31, 2020 represents the deferred income tax effect of the equity component of the convertible debentures issued in 2020.

Clearview has no current income taxes payable and has estimated tax pools available against income of $145.4 million, including non-capital tax loss carry-forwards of $78.1 million which will expire over the years 2024 to 2040. The successor pools were acquired as part of oil and gas property acquisitions in March 31, 2017 and the acquisition of Bashaw Oil Corp. on April 16, 2018. The successor pools can be deducted to the extent of future profits attributable to the acquired properties. During the taxation years ended March 31, 2017 to December 31, 2021, Clearview has claimed $20.3 million against the successor pools.

The Company's tax pools as at December 31, 2021 are set out below:

Nature of tax pool	%[1]	Regular	Successor[2]	Total
Canadian exploration expense (CEE)	100	170	11,263	11,433
Canadian development expense (CDE)	30	4,376	10,978	15,354
Canadian oil and gas property expense (COGPE)	10	24,486	6,521	31,007
Foreign resource expenses	10	4,012	-	4,012
Undepreciated capital cost (UCC)	25	5,502	-	5,502
Share issue costs	20	5	-	5
Non-capital losses carry forward	100	78,071	-	78,071
Total tax pools		116,622	28,762	145,384

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

Adjusted funds flow

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

	Three months ended			Year ended			
	Dec. 31 2021	Dec. 31 2020	% Change	Dec. 31 2021	Dec. 31 2020	% Change	2019
Cash flow provided by operating activities	2,065	55	3,654	6,130	1,783	244	4,980
Add back (deduct)							
Decommissioning expenditures	162	83	95	341	136	151	225
Change in non-cash working capital	(430)	819	(153)	(898)	568	(258)	289
Adjusted funds flow (1)	1,797	957	88	5,573	2,487	124	5,494

(1) Non-IFRS measure or ratio that does not have any standardized meaning as prescribed by International Financial Reporting Standards and therefore may not be comparable with the calculations of similar measures or ratios of other entities. See "Non-IFRS Measures" contained within this MD&A.

Adjusted funds flow increased 88% for the three months ended December 31, 2021, primarily due to higher revenues, lower cash finance costs and a gain from an overriding royalty settlement with a joint venture partner. For the quarter ended December 31, 2021, cash provided by operating activities was $2.6 million compared to $55 thousand for the quarter ended December 31, 2020. The increase of 3,654% was primarily due to higher revenues.

For the year ended December 31, 2021 adjusted funds flow was $5.6 million compared to $2.5 million for the year ended December 31, 2020. The increase of 124% was due to higher revenues from much higher realized prices being offset by higher royalties, higher transportation and operating costs, higher general and administrative costs and higher realized losses on financial instruments. For the year ended December 31, 2021, cash provided by operating activities was $6.1 million compared to $1.8 million for the year ended December 31, 2020. The increase of 244% was primarily due to higher revenues, lower cash finance costs and a gain from a settlement with a royalty holder.

Net loss

	Three months ended			Year ended		
	Dec. 31 2021	Dec. 31 2020	% Change	Dec. 31 2021	Dec. 31 2020	% Change
Net earnings (loss)	10,512	16,891	(38)	5,212	(10,842)	(148)
Per boe	55.86	88.61	(37)	6.74	(14.42)	(147)
Per share – basic	0.90	1.45	(38)	0.45	(0.93)	(148)
Per share – diluted	0.82	1.45	(43)	0.42	(0.93)	(145)

The Company generated net earnings of $10.5 million for the three months ended December 31, 2021 compared to net earnings of $16.9 million for the comparative quarter. The decrease in the net earnings for the three months ended December 31, 2021 was primarily due to a much larger impairment reversal in the fourth quarter of 2020 than the impairment reversal in the fourth quarter of 2021.

The increase to net earnings for the year ended December 31, 2021 of $5.2 million from a net loss of $10.8 million for the year ended December 31, 2020 was primarily due to much higher revenue from higher realized sales prices in 2021 and an impairment reversal of $8.3 million in 2021 versus an impairment expense of $4.3 million in 2020.

Netback analysis

	Three months ended			Year ended		
Barrel of oil equivalent ($/boe)	Dec. 31 2021	Dec. 31 2020	% Positive (Negative)	Dec. 31 2021	Dec. 31 2020	% Positive (Negative)
Realized sales price	47.39	25.55	85	39.26	21.45	83
Royalties	(8.79)	(0.51)	(1,624)	(5.52)	(1.18)	(368)
Processing income	0.68	0.62	10	0.61	0.69	(12)
Transportation	(1.55)	(1.56)	1	(1.69)	(1.57)	(8)
Operating	(16.83)	(12.21)	(38)	(15.80)	(13.44)	(18)
Operating netback (2)	20.90	11.89	76	16.86	5.95	183
Realized gain (loss) – financial instruments	(8.44)	(0.41)	(1,959)	(5.85)	1.59	(468)
General and administrative	(3.10)	(2.31)	(34)	(2.84)	(2.14)	(33)
Other (costs) income	1.75	(1.07)	264	0.51	(0.27)	289
Cash finance costs (2)	(1.57)	(3.06)	49	(1.48)	(1.82)	19
Corporate netback (2)	9.54	5.04	89	7.20	3.31	118
Unrealized gain (loss) – financial instruments	10.46	1.53	584	(0.88)	(0.28)	(214)
Stock based compensation	(0.27)	(0.65)	58	(0.26)	(0.50)	48
Depletion and depreciation	(9.29)	(10.79)	14	(10.24)	(10.73)	5
Impairment (expense)/reversal	44.11	94.42	(53)	10.73	(5.72)	288
E&E expense	-	(0.55)	100	-	(0.14)	(100)
Accretion	(0.29)	(0.47)	38	(0.60)	(0.38)	(58)
Other (costs) income	1.60	-	100	0.78	-	100
Deferred income taxes	-	0.08	(100)	-	0.02	(100)
Net earnings (loss)	55.86	88.61	(37)	6.73	(14.42)	147

(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) Non-IFRS measure or ratio that does not have any standardized meaning as prescribed by International Financial Reporting Standards and therefore may not be comparable with the calculations of similar measures or ratios of other entities. See “Non-IFRS Measures” contained within this MD&A.

The Company’s corporate netback for the quarter ended December 31, 2021 increased 89% to $9.54 per boe versus the comparative period. The increase is primarily due to higher realized sales price per boe partially offset by higher royalties per boe and higher operating costs per boe in the current period versus the comparative period.

SUMMARY OF QUARTERLY RESULTS

	Dec 31	Sep 30	Jun 30	Mar 31	Dec 31	Sep 30	Jun 30	Mar 31
Three months ended	2021	2021	2021	2021	2020	2020	2020	2020
Production								
Oil (bbl/d)	433	450	504	463	487	531	320	582
Natural gas liquids (bbl/d)	487	467	549	350	345	410	387	431
Natural gas (mcf/d)	6,755	6,942	7,233	7,715	7,443	7,143	6,058	7,716
Total (boe/d)	2,045	2,074	2,258	2,098	2,072	2,132	1,716	2,299
Financial								
Oil and natural gas sales	8,918	7,788	7,207	6,451	4,870	4,371	2,350	4,542
Net earnings (loss)	10,512	(1,101)	(2,527)	(1,672)	16,891	(1,761)	(2,755)	(23,217)
Per share – basic	0.90	(0.09)	(0.22)	(0.14)	1.45	(0.15)	(0.24)	(1.99)
Per share - diluted	0.82	(0.09)	(0.22)	(0.14)	1.45	(0.15)	(0.24)	(1.99)

(1) Non-IFRS measure or ratio does not have any standardized meaning as prescribed by International Financial Reporting Standards and therefore may not be comparable with the calculations of similar measures or ratios of other entities. See “Non-IFRS Measures” contained within this MD&A.

In the fourth quarter of 2021, oil and natural gas sales increased to $8.9 million as a result of higher prices for crude oil, pentanes, propane and butanes and higher production volumes of natural gas liquids. The increase in revenue of $1.1 million was primarily offset higher royalties of $0.7 million, an increase in the realized loss on financial instruments of $0.2 million but other income of $0.3 million as compared to the third quarter of 2021. Net earnings for the three months ended December 31, 2021 was $10.5 million ($0.90 per basic share), primarily as a result of an impairment reversal of $8.3 million.

In the third quarter of 2021, oil and natural gas sales increased to $7.8 million as a result of higher prices for crude oil, natural gas, pentanes, propane and butanes and higher production volumes of natural gas liquids. The increase in revenue of $0.6 million was primarily offset by an increase in the realized loss on financial instruments of $0.4 million but lower royalty costs of $0.3 million as compared to the second quarter of 2021. The net loss for the three months ended September 30, 2021 was $1.1 million ($0.09 per basic share).

In the second quarter of 2021, oil and natural gas sales increased to $7.2 million as a result of higher prices for crude oil, pentanes and butanes and higher production volumes of crude oil and natural gas liquids. The increase in revenue of $0.8 million was primarily offset by an increase in the realized loss on financial instruments of $0.5 million and higher royalty costs as compared to the first quarter of 2021. The net loss for the three months ended June 30, 2021 was $2.5 million ($0.22 per basic share).

In the first three months of 2021, oil and natural gas sales increased to $6.5 million as a result of higher prices for crude oil and natural gas liquids production and much higher prices for natural gas production as a result of extreme cold weather during February. The increase in revenue of $1.6 million was partially offset by an increase in the realized loss on financial instruments of $0.4 million and higher operating costs as compared to the fourth quarter of 2020. The net loss for the three months ended March 31, 2021 was $1.7 million ($0.14 per basic share). Net debt was reduced by $0.8 million during the first quarter of 2021 as the excess of adjusted funds flow over capital expenditures and abandonment and reclamation expenditures of $0.8 million was applied against bank debt and working capital.

In the fourth quarter of 2020, production was slightly lower than the previous quarter due to normal production declines and continued minimal spending on workovers or optimization projects. Oil and natural gas sales increased by 11% in the three months ended December 31, 2020 from the previous quarter due to higher realized sales prices. Higher oil and natural gas sales were partially offset primarily by an increase in other costs and cash finance costs. The net earnings for the three months ended December 31, 2020 was $16.9 million compared to a net loss of $1.8 million in the previous quarter. The significant change in net earnings was a result of an impairment reversal of $18.6 million in the fourth quarter due to a significant improvement in commodity prices compared to the first quarter of 2020 and positive technical revisions in the Company's reserves at December 31, 2020.

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. 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. 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. 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.

LIQUIDITY AND CAPITAL RESOURCES

The Company has a planned capital program of $1.5 to $2.0 million for 2022, primarily of discretionary expenditures and no significant commitments. The Company's expected 2022 adjusted funds flow and credit capacity should provide the liquidity to execute this capital program.

The Company's liquidity was strengthened during the current fiscal year as net debt was reduced by $3.0 million as Clearview's adjusted funds flow in 2021 in excess of net capital expenditures and decommissioning expenditures was used to repay outstanding bank debt.

As a result, net debt is $10.2 million at December 31, 2021, down from $13.2 million at December 31, 2020, with the components set out below.

As at	Dec. 31, 2021	Dec. 31, 2020
Cash and cash equivalents	1,183	-
Trade and other receivables	2,933	2,724
Prepaid expenses and deposits	703	640
Bank debt	(8,772)	(12,296)
Accounts payable and accrued liabilities	(4,622)	(2,767)
Decommissioning obligations	(410)	(342)
Convertible debentures	(1,208)	(1,194)
Net debt (1)	(10,193)	(13,235)

(1) Non-IFRS measure or ratio that does not have any standardized meaning as prescribed by International Financial Reporting Standards and therefore may not be comparable with the calculations of similar measures or ratios of other entities. See “Non-IFRS Measures” contained within this MD&A.

Balance sheet strength and flexibility remain a priority of the Company even through this much improved commodity price environment extending into 2022. The Company continues to consider funding alternatives, including an 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. The Company monitors net debt as a key component of managing liquidity risk and determining capital resources available to finance future development.

As of December 31, 2021, the Company has a revolving, operating demand loan (“Operating Facility”) with an Alberta based financial institution (“Lender”) with a facility limit of $8.75 million (December 31, 2020 - $15.0 million). Additionally, Clearview has a $6.25 million term loan through its Lender under the Business Credit Availability Program (“BCAP”), supported by the Export Development Canada (“EDC”) Guarantee (“EDC Facility”) providing a total credit capacity of $15.0 million.

The Operating Facility is reserve-based, revolving and payable on demand. 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. Drawings under the facility can be undertaken in the form of prime-based loans or guaranteed notes offered by the Lender.

The EDC Facility is a non-revolving term facility to be used exclusively to provide additional liquidity for the Company’s business operations. The facility can be used to pay operating expenses, G&A expenses, interest on the Operating Facility and pay down temporary advances on the Operating Facility. The EDC Facility cannot be used to repay or refinance permanent reductions to the Operating Facility or to make shareholder contributions, shareholder loans, share buy backs or pay any bonuses or increase executive compensation.

The EDC Facility is payable on demand by the Lender and is non-revolving. 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. The principal amount outstanding must be repaid no later than 50% by November 30, 2024 with the remaining principal outstanding due for repayment by November 30, 2025.

The Operating Facility and EDC Facility are 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 interest rates applicable to drawings under the facilities are based on a pricing margin grid and can change quarterly as a result of the ratio of all outstanding indebtedness to annualized quarterly funds flows as calculated in accordance with the agreement governing the facility (“Debt to Funds Flow”). Annualized quarterly funds flow is defined as earnings before depletion and depreciation, stock based compensation, accretion of decommissioning obligations and debenture discounts, unrealized gains or losses on commodity contracts, gains or losses on dispositions, non-cash other costs (income) and deferred income taxes.

Under the Operating Facility, prime-based loans are subject to an interest rate of lender prime plus a credit spread of 2.75% to 5.75%, depending on the Debt to Funds Flow of less than 1.0 to greater than 4.0.

Guaranteed notes are subject to the Canadian Dollar Offered Rate ("CDOR") plus a stamping fee of 3.75% to 6.75%, depending on the Debt to Funds Flow of less than 1.0 to greater than 4.0. Guaranteed notes may be undertaken for terms of 30, 60, 90 or 180 days.

Under the EDC Facility, the loan is subject to an interest rate of lender prime plus a credit spread of 2.75% to 5.75%, depending on the Debt to Funds Flow of less than 1.0 to greater than 4.0.

The Company is subject to certain reporting and financial covenants, pursuant to its lending agreement. The agreement requires compliance with a working capital covenant whereby the Company must maintain a minimum working capital ratio of 1 to 1. For calculating compliance with this covenant, the amount drawn on the Operating Facility and EDC Facility, classified as a current liability, and the fair value of financial instruments are excluded from working capital. Conversely, the amount of the undrawn portion of the Operating Facility is added to current assets. At December 31, 2021, the Company's working capital ratio for purposes of the lender's working capital covenant was 2.2:1 (4.0:1 at December 31, 2020). In addition, the Company and its lender have agreed to a covenant whereby the Company shall maintain a liability management rating ("LMR") of no less than 2.0. Clearview's LMR as at December 31, 2021 was 2.3. The Company is also required to maintain commodity swap contracts for 50% (approximately 3,000 GJ per day) of its natural gas production volumes and 250 barrels per day of its oil production volumes. The Company has satisfied the requirement to contract a portion of its production volumes as per the lending agreement.

At December 31, 2021, the Company had $2.5 million of guaranteed notes, $25 thousand in prime-based loans and $10 thousand in letters of credit outstanding on the Operating Facility and $6.25 million outstanding on the EDC Facility.

The next credit review is scheduled to be completed by no later than June 30, 2022. In the event that the Operating Facility limit is reduced and the amount outstanding exceeds this facility limit, the Company shall have thirty days to repay any shortfall.

On December 1, 2020, the Company issued $1.26 million of unsecured convertible debentures at a price of $100 per debenture. The interest rate on the debenture is 10%, payable quarterly in arrears on March 31, June 30, September 30 and December 31 of each year. During the term of the debenture, 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 debentures have a term of five years and mature on November 30, 2025. The debentures may not be redeemed by the Company prior to December 1, 2021. During the remainder of the term, the Company may redeem the debentures over the term based on the following terms:

Year 2 – 110% of the principal amount plus accrued interest
Year 3 – 105% of the principal amount plus accrued interest
Years 4 and 5 – 100% of the principal amount plus accrued interest

The subscribers to the debenture offering consisted of current shareholders of the Company, with the directors and officers of the Company participating in the offering.

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.

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, 2022 and may be cancelled by either the Company or the landlord on three month's notice to the other party. The following is a summary of the Company's future minimum contractual obligations and commitments as of December 31, 2021.

	2022	2023	2024	2025	2026	Thereafter
Bank debt	8,772	-	-	-	-	-
Accounts payable and accrued liabilities	4,622	-	-	-	-	-
Decommissioning obligations	410	410	410	410	410	23,015
Convertible debentures	-	-	-	1,262	-	-
Gas transportation	5	-	-	-	-	-
Office lease	56	-	-	-	-	-
Total	13,865	410	410	1,672	410	23,015

OFF-BALANCE SHEET ARRANGEMENTS

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

OUTSTANDING SHARE DATA

The Company is authorized to issue an unlimited number of voting common shares, an unlimited number of non-voting common shares and an unlimited number of preferred shares, issuable in series. As of April 21, 2022, the Company has 11,671,387 voting common shares outstanding and 562,100 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 between $1.25 and $5.00 per option.

Vesting period	Options-$4.50	Options-$5.00	Options-$1.25	Options-$3.96	Total
Currently vested	154,000	92,500	88,534	-	335,034
Vesting in the future in the three months ending					
December 31, 2022			88,533	16,667	105,200
December 31, 2023			88,533	16,667	105,200
December 30, 2024			-	16,666	16,666
Total	154,000	92,500	265,600	50,000	562,100

For further details about the options refer to Note 9 to the financial statements as at and for the period ended December 31, 2021.

RELATED PARTY TRANSACTIONS

There were no related party transactions in the twelve months ended December 31, 2021.

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, 2021 and December 31, 2020. Certain estimates and judgments are described in Note 2 to the audited financial statements for the periods ended December 31, 2021 and December 31, 2020.

Impact of COVID-19

In the first quarter of 2020, the World Health Organization declared COVID-19 to be a pandemic. Responses to the spread of COVID-19 resulted in a sudden decline in economic activity and a significant increase in economic uncertainty. In addition, oil prices declined dramatically due to the global oil price war and the decline in demand due to COVID-19. These events resulted in a volatile and challenging economic environment throughout 2020 which adversely affected the Company's operational results and financial position.

Throughout 2021, both oil and natural gas prices improved significantly, largely due to a combination of improved global economic activity combined with reduced oil and natural gas supply and the roll-out of COVID-19 vaccinations. Estimates and judgments made by management in the preparation of the financial statements are increasingly difficult and subject to a higher degree of measurement uncertainty during this volatile period.

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 1.82% 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.

Stock based compensation

The Company's accounting policy for stock based compensation was applied to account for the options granted during the periods ended December 31, 2021 and December 31, 2020. 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.

Lease obligations

Lease obligations are estimated using the rate implicit in the lease, unless this rate is not readily determinable, in which case a discount rate equal to the Company's incremental borrowing rate is used.
This rate represents the rate that the Company would incur to obtain the funds necessary to purchase an asset of a similar value, with similar payment terms and security in a similar economic environment. Lease terms are based on assumptions regarding extension terms and renewal options that allow for operational flexibility and future market conditions.

Liquidity

As part of its capital management process, the Company prepares budgets and forecasts, which are used by management and the Board of Directors to direct and monitor the strategy, ongoing operations and liquidity of the Company. Budgets and forecasts are subject to significant judgement and estimates relating to activity levels, future cash flows and the timing thereof and other factors which may or may not be within the control of the Company. See further discussion related to liquidity in Note 14.

NEW ACCOUNTING POLICIES

New accounting standards

Various amendments to existing standards and new accounting requirements have been released that are effective January 1, 2022. The Company does not expect the new requirements to have a material impact on the financial statements.

Future accounting pronouncements

On January 23, 2020, the International Accounting Standards Board announced an amendment to IAS 1 "Presentation of financial statements re; classification of liabilities as current or non-current which is effective for annual periods beginning on or after January 1, 2023. The amendment clarifies that the classification of liabilities as current or non-current should be based on rights that are in existence at the end of the reporting period. The Company does not plan to early adopt these amendments.

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 14 of the audited financial statements for the year ended December 31, 2021 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.

Widening concerns over climate change, fossil fuel consumption, green house gas emissions, and water and land use could lead governments to enact additional laws, regulations and costs or taxes that may be applicable to Clearview. Changes to environmental regulations related to climate change could impact the demand for, development of or quality of the Company's petroleum products, or could require increased capital expenditures, operating expenses, asset retirement obligations and costs, which could result in increased costs which would reduce the profitability and competitiveness of Clearview if commodity prices do not rise commensurate with the increased costs. In addition, such regulatory changes could necessitate the Company to develop or adapt new technologies, possibly requiring significant investments of capital.

Emissions, carbon and other regulations impacting climate and climate-related matters are constantly evolving. With respect to environmental, social and governance ("ESG") and climate reporting, the International Sustainability Standards Board has issued an IFRS Sustainability Disclosure Standard with the aim to develop sustainability disclosure standards that are globally consistent, comparable and reliable. In addition, the Canadian Securities Administrators have issued a proposed National Instrument 51-107 Disclosure of Climate-related Matters. The cost to comply with these standards, and others that may be developed or evolve over time, has not yet been quantified.

Non-IFRS Measures

Throughout this MD&A and other materials disclosed by the Company, Clearview uses certain measures to analyze financial performance, financial position and cash flow. These non-IFRS and other financial measures do not have any standardized meaning prescribed under IFRS and therefore may not be comparable to similar measures presented by other entities. The non-IFRS and other financial measures should not be considered alternatives to, or more meaningful than, financial measures that are determined in accordance with IFRS as indicators of Clearview's performance. Management believes that the presentation of these non-IFRS and other financial measures provides useful information to shareholders and investors in understanding and evaluating the Company's ongoing operating performance, and the measures provide increased transparency and the ability to better analyze Clearview's business performance.

Capital Management Measures

Adjusted Funds Flow

Adjusted funds flow represents cash provided by operating activities before changes in operating non-cash working capital and decommissioning expenditures. The Company considers this metric as a key measure that demonstrate the ability of the Company's continuing operations to generate the cash flow necessary to maintain production at current levels and fund future growth through capital investment, to repay debt and return capital to shareholders. Management believes that this measure provides an insightful assessment of the Company's operations on a continuing basis by eliminating the actual settlements of decommissioning obligations, the timing of which is discretionary. Adjusted funds flow should not be considered as an alternative to or more meaningful than cash provided by operating activities as determined in accordance with IFRS as an indicator of the Company's performance. Clearview's determination of adjusted funds flow may not be comparable to that reported by other companies. Clearview also presents adjusted funds flow per share whereby per share amounts are calculated using weighted average shares outstanding consistent with the calculation of earnings per share.

Net Debt

Clearview closely monitors its capital structure with a goal of maintaining a strong balance sheet to fund the future growth of the Company. The Company monitors net debt as part of its capital structure. The Company uses net debt (current assets, excluding financial derivatives, less current liabilities, excluding financial derivatives, less convertible debentures to assess financial strength, capacity to finance future development and to assist in assessing the liquidity of the Company.

Non-IFRS Measures and Ratios

Capital Expenditures

Capital expenditures equals additions to property, plant & equipment and additions to exploration & evaluation assets. Clearview considers capital expenditures to be a useful measure of adjusted funds flow used for capital reinvestment. The most directly comparable IFRS measure to capital expenditures is additions to property, plant & equipment and additions to exploration & evaluation assets.

Net Capital Expenditures

Net capital expenditures equals capital expenditures plus acquisitions of property, plant & equipment and less dispositions of property, plant & equipment. Clearview uses net capital expenditures to measure its total capital investment compared to the Company's annual capital budget expenditures. The most directly comparable IFRS measure to net capital expenditures is cash used in investing activities.

	Three months ended		Year ended	
	Dec. 31 2021	Dec. 31 2020	Dec. 31 2021	Dec. 31 2020
Cash used in investing activities	624	202	1,423	534
Changes in non-cash working capital	16	(148)	685	(158)
Net capital expenditures	640	54	2,108	376

Cash Finance Costs per boe

Cash finance costs per boe is calculated by dividing cash finance costs by total production volumes sold in the period. Management considers cash finance costs per boe an important measure to evaluate the Company's cost of debt financing relative to the Company's corporate netback per boe. The most directly comparable IFRS measure to cash financing costs is finance costs.

	Three months ended		Year ended	
	Dec. 31 2021	Dec. 31 2020	Dec. 31 2021	Dec. 31 2020
Finance costs	350	673	1,610	1,657
Accretion of decommissioning obligations and convertible debentures	(55)	(89)	(462)	(287)
Cash finance costs	295	584	1,148	1,370

Operating Netback per boe

Operating netback per boe is calculated by dividing operating netback by total production volumes sold in the period. Operating netback equals oil and natural gas sales plus processing income, less royalties, transportation expenses and operating expenses. Management considers operating netback per boe an important measure to evaluate its operational performance as it demonstrates its field level profitability relative to current commodity prices. The calculation of Clearview's operating netback per boe can be seen in the section entitled "Netback Analysis" of this MD&A.

Corporate Netback per boe

Corporate netback per boe is calculated as operating netback less general and administrative expenses and finance costs, plus/(minus) realized gains (losses) on financial instruments, minus(plus) other costs (income), plus accretion of decommissioning obligations and convertible debentures divided by total production volumes sold in the period. Management considers corporate netback per boe an important measure to assist management and investors in assessing Clearview's overall cash profitability. The calculation of Clearview's corporate operating netback per boe can be seen in the section entitled "Netback Analysis" of this MD&A.

Supplementary Financial Measures

Adjusted funds flow per share is comprised of adjusted funds flow divided by the basic weighted average common shares.

Adjusted funds flow per diluted share is comprised of adjusted funds flow divided by the diluted weighted average common shares.

Realized sales price – oil is comprised of light crude oil commodity sales from production, as determined in accordance with IFRS, before deduction of transportation costs and excluding gains and losses on financial instruments, divided by the Company's oil production.

Realized sales price - ngl is comprised of natural gas liquids commodity sales from production, as determined in accordance with IFRS, before deduction of transportation costs and excluding gains and losses on financial instruments, divided by the Company's ngl production.

Realized sales price – natural gas is comprised of natural gas commodity sales from production, as determined in accordance with IFRS, before deduction of transportation costs and excluding gains and losses on financial instruments, divided by the Company's natural gas production.

Realized sales price – total is comprised of oil and natural gas sales from production, as determined in accordance with IFRS, before deduction of transportation costs and excluding gains and losses on financial instruments, divided by the Company's total production on a boe basis.

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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