CLEARVIEW
RESOURCES LTD

Clearview Resources Ltd.

Management Discussion and Analysis (MD&A)

September 30, 2021

HIGHLIGHTS

- The Company reduced net debt by $0.5 million in the third quarter of 2021, down to $11.1 million, with a net debt to annualized adjusted funds flow ratio of 1.85:1;

- Production averaged 2,074 barrels of oil equivalent per day (“boe/d”), a decrease of 3%, versus the third quarter of 2020. Oil and natural gas production was reduced in the Windfall area for most of July due to a third party natural gas processing facility upgrade being completed by the operator;

- During the third quarter, Clearview acquired Crown land in the Jarvie area of Alberta focused on the developing Clearwater oil play in the region;

- Commodity prices continued to rise in the third quarter of 2021, with natural gas increasing 61% to average $3.60 per million cubic feet (“mcf”), and Canadian light oil increasing 68% to average $83.81 per barrel versus the third quarter of 2020;

- Clearview’s realized sales price was $40.82 and $36.65 per barrel of oil equivalent (“boe”) for the three and nine months ended September 30, 2021, respectively, an increase of 83% for both periods versus the third quarter of 2020;

- The increase in realized sales prices per boe and growth in production resulted in the Company’s operating netback being $18.89 and $15.57 per boe in the three and nine months ended September 30, 2021, respectively, representing an increase of 148% and 296% versus in 2020;

- In the quarter ended September 30, 2021, Clearview generated adjusted funds flow of $1.5 million ($0.13 per share) and cash flow from operations of $2.1 million as compared to $0.9 million ($0.08 per share) and $0.9 million, respectively, in the third quarter of 2020;

- In the nine months ended September 30, 2021, Clearview has completed abandonment operations on 9 gross (8.4 net) wells incurring $0.2 million of cash expenditures and utilizing $0.3 million of Site Rehabilitation Program grants from the Alberta Government; and

- Subsequent to the third quarter of 2021, the Company’s lender completed its annual credit review and established the credit facilities for the Company at a total of $15.0 million, consisting of an operating facility of $8.75 million and a $6.25 million facility with Export Development Canada.

Clearview Resources Ltd.
Management Discussion and Analysis (MD&A)
September 30, 2021

The management discussion and analysis ("MD&A") is a review of the financial position and results of operations of the Company for the three and nine months ended September 30, 2021 and 2020. The MD&A should be read in conjunction with the Company's unaudited condensed interim financial statements and accompanying notes for the three and nine months ended September 30, 2021 and 2020 and the audited financial statements and accompanying notes for the years ended December 31, 2020 and 2019. The unaudited condensed interim financial statements have been prepared in accordance with International Accounting Standard 34, Interim Financial Reporting. Unless otherwise noted, all dollar amounts in the tables are expressed in thousands of Canadian dollars ($000's), except per unit amounts. The MD&A has been prepared and approved by the Board of Directors as of November 18, 2021.

Refer to page 26 for information about non-GAAP measures, page 27 for information on forward-looking statements and page 28 for measures, conversions and acronyms used in the MD&A.

OVERVIEW OF THE COMPANY

Clearview Resources Ltd. (the "Company") is a privately owned, growth-oriented oil and natural gas producing company based in Calgary, Alberta with production and development primarily focused in the Greater Pembina area of west central Alberta. 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	5,300	87%	Yes
	Pembina	Liquids rich natural gas	1,236	80%	Yes
	Wilson Creek	Light oil and liquids rich natural gas	3,576	60%	Yes
	Windfall	Light oil	4,990	100.0%	Yes
	Niton	Light oil	1,351	96%	Yes
	Garrington	Light oil and liquids rich natural gas	1,469	94%	Yes
	Caribou	Light oil	558	63.3%	Yes
Other	Bantry	Medium oil	257	40.0%	No
	Carstairs (Unit)	Liquids rich natural gas	579	17.0%	No
	Lindale (Unit)	Light oil with associated natural gas and liquids	91	10.6%	No
	Miscellaneous	Various	89	Various	Mixed
Total			19,496		

[1] mboe of total proved plus probable reserves at December 31, 2020 as determined by the Company's independent reserves evaluator, McDaniel & Associates Consultants Ltd.
[2] operatorship of a majority of the property

The Company's objectives continue to be:

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

SELECTED ANNUAL INFORMATION

	Nine months ended		Periods ended		
	Sept. 30 2021	Sept. 30 2020	Dec. 31 2020	Dec. 31 2019	Dec. 31 2018
Oil and natural gas sales	21,446	11,263	16,133	25,687	16,273
Adjusted funds flow (1)	4,080	1,530	2,487	5,494	1,852
Per share – basic	0.35	0.13	0.21	0.48	0.18
Per share – diluted	0.35	0.13	0.21	0.48	0.18
Cash flow from operations	3,848	1,728	1,783	4,980	1,088
Per share – basic	0.33	0.15	0.15	0.43	0.11
Per share - diluted	0.33	0.15	0.15	0.43	0.11
Net earnings (loss)	(5,300)	(27,733)	(10,842)	(8,768)	(4,832)
Per share – basic	(0.45)	(2.38)	(0.93)	(0.76)	(0.48)
Per share – diluted	(0.45)	(2.38)	(0.93)	(0.76)	(0.48)
Total assets	64,234	53,307	70,498	80,038	80,752
Total long-term liabilities	23,551	25,350	26,387	23,420	22,645
Net debt (1)	11,115	14,203	13,235	15,358	18,186
Total capital expenditures – net (2)	1,468	322	376	1,955	6,172

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

In the first nine months of 2021, oil and natural gas sales increased to $21.4 million as a result of higher realized sales prices for crude oil, natural gas and natural gas liquids as well as higher natural gas liquids production. The increase in revenue of $10.2 million was partially offset by a negative change in realized gains on financial instruments of $4.2 million as compared to the same period of 2020. As a result, adjusted funds flow increased to $4.1 million ($0.35 per share) in the first nine months of 2021. Cash flow from operations increased to $3.8 million in the nine months ended September 30, 2021. The net loss for the nine months ended September 30, 2021 was $5.3 million ($0.45 per share) versus a net loss of $27.8 million ($2.38 per share) in the comparative period. The significant difference in the net loss was primarily due to an impairment expense of $22.3 million in the first quarter of 2020. Net debt was reduced by $2.1 million during the nine months ended September 30, 2021 as the excess of adjusted funds flow over capital expenditures and abandonment and decommissioning expenditures of $2.0 million was applied against bank debt and working capital.

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 flow from operations 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.

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

DISCUSSION OF OPERATIONS

Acquisitions and dispositions

Acquisition of assets

During the nine months ended September 30, 2020, the Company acquired working interests of joint venture partners in 9 gross (3.5 net) wells in its Central Alberta Oil CGU. The joint venture partners paid Clearview $0.3 million to acquire their working interests, representing the value of the assets less the cost of decommissioning obligations of $0.3 million.

Capital expenditures

	Three months ended			Nine months ended		
	Sept. 30 2021	Sept. 30 2020	% Change	Sept. 30 2021	Sept. 30 2020	% Change
Land	121	-	100	121	3	3,933
Drilling, completions, equipping	357	50	614	950	300	217
Facilities	307	163	88	369	253	46
Other	8	20	(60)	28	27	4
Capital invested	793	233	240	1,468	583	152
Disposition of properties	-	-	-	-	-	-
Net capital invested	793	233	240	1,468	583	152
Acquisition of properties	-	(114)	(100)	-	(261)	(100)
Total capital expenditures	793	119	567	1,468	322	356

The Company spent approximately 36% of its adjusted funds flow on capital expenditures in the first nine months ended September 30, 2021. The capital expenditures incurred were primarily for facility upgrades and well workovers and optimizations as part of an approved optimization program. The second phase of an optimization program was completed in the third quarter of 2021 resulting in production additions for the 2021 optimization programs of approximately 280 boe/d.

During the third quarter of 2021, the Company acquired lands in the Jarvie area of Alberta for $121 thousand.

Production

Production is summarized in the following table:

	Three months ended			Nine months ended		
	Sept. 30 2021	Sept. 30 2020	% Change	Sept. 30 2021	Sept. 30 2020	% Change
Oil – bbl/d	450	531	(15)	472	478	(1)
Natural gas liquids – bbl/d	467	410	14	456	410	11
Total liquids – bbl/d	917	941	(3)	928	888	5
Natural gas – mcf/d	6,942	7,143	(3)	7,294	6,973	5
Total – boe/d	2,074	2,132	(3)	2,143	2,050	5

Production for the quarter ended September 30, 2021 decreased by 3% versus the comparative period. The decrease in production was primarily due to the Company's Windfall property being shut-in for the month of July due to turnaround operations undertaken by the third-party natural gas processing facility. Natural gas liquids, generally associated with natural gas production, increased 14% for the quarter ended September 30, 2021 versus the comparative period due to a change in natural gas processing facility for a portion of the Company's natural gas production, effective in September 2020, which extracts greater ethane volumes.

Production for the nine months ended September 30, 2021 increased 5% over the comparative period of 2020 primarily due to the capital spending undertaken in the first and third quarters of 2021 on well optimization projects predominantly for liquids rich natural gas projects. The comparative period of 2020 was negatively affected by shut-in volumes due to the COVID-19 pandemic.

Clearview's production portfolio for the nine months ended September 30, 2021 was weighted 22% to oil, 21% to natural gas liquids and 57% to natural gas. For the nine months ended September 30, 2020, the production mix was weighted 23% to oil, 20% to natural gas liquids and 57% to natural gas. The slight change in product mix over the comparative period has been influenced by the change in natural gas processing facility in the third quarter of 2020. A majority of the natural gas produced by the Company is either associated with light oil production or has significant natural gas liquids in the natural gas production stream.

Benchmark prices and economic parameters

	Three months ended			Nine months ended		
	Sept. 30 2021	Sept. 30 2020	% Change	Sept. 30 2021	Sept. 30 2020	% Change
Oil – West Texas Intermediate ("WTI") (US $/bbl)	70.59	40.94	72	64.85	38.29	69
Oil – Edmonton Par ($/bbl)	83.81	49.88	68	75.91	43.69	74
Differential – Light oil ($/bbl) (1)	5.10	4.65	10	5.18	8.12	(36)
NGLs - Pentane ($/bbl)	89.28	51.73	73	81.14	47.83	70
NGLs – Butane ($/bbl)	59.37	19.15	210	41.60	22.70	83
NGLs – Propane ($/bbl)	53.11	14.20	274	38.32	16.35	134
Natural gas – AECO ($/mcf)	3.60	2.24	61	3.27	2.10	56
Exchange rate – US$/Cdn$	0.794	0.751	6	0.799	0.739	8

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

The refiners' posted prices for Canadian crude oils are influenced by the WTI reference price, transportation capacity and costs, US$/Cdn$ exchange rates and the supply/demand situation of particular crude oil quality streams during the period. Benchmark oil prices in the three months ended September 30 increased from an average of US $40.94 per barrel in 2020 to US $70.59 per barrel in the third quarter of 2021 resulting in a 72% increase. 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 light oil prices increased by 68% in the three months ended September 30, 2021 compared to the same quarter in 2020 as the Canadian dollar strengthened by 6% and the light oil differential widened by 10% over the same comparative quarter, both weakening Canadian prices.

For the first nine months of 2021, Canadian light oil prices have increased by 74% over the comparative period, with significant increases for pentane, butane and propane, reflective of a 69% increase in the price of WTI.

Pentane prices increased over the three months ended September 30, 2021 in a very similar manner to WTI pricing and Canadian light oil prices with an increase of 73% versus the comparative period of 2020.

Butane prices averaged $59.37 per barrel for the quarter ended September 30, 2021, an increase of 210% from the same quarter of 2020. The increase in butane prices is consistent with the increase in WTI and Edmonton Par as well as increased demand for the product with the recovery of the North American economy.

Propane prices averaged $53.11 per barrel for the quarter ended September 30, 2021, an increase of 274% compared to the same quarter 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 $3.60 per mcf for the three months ended September 30, 2021, an increase of 61% as compared to the same quarter of 2020. AECO pricing was very strong throughout the third quarter of 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. For the nine months ended September 30, 2021, AECO increased by 56% versus the comparative period, to average $3.27 per mcf. AECO prices are expected to be strong for the remainder of the year and through the upcoming winter heating season.

Realized sales prices

	Three months ended			Nine months ended		
	Sept. 30 2021	Sept. 30 2020	% Change	Sept. 30 2021	Sept. 30 2020	% Change
Oil – $/bbl	79.03	43.67	81	71.36	40.16	78
NGLs – $/bbl	47.17	22.51	110	41.21	18.61	121
Natural gas – $/mcf	3.90	2.11	85	3.58	2.05	75
Total – $/boe	40.82	22.29	83	36.65	20.06	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 September 30, 2021, the Company's realized oil price was higher by 81% than the comparative quarter as a result of a 68% increase in Edmonton Par benchmark pricing.

Natural gas liquids prices were higher by 110% in the third quarter of the current year as compared to the same quarter of the prior year. This increase was primarily due to significantly higher prices received for the Company's propane, butane and pentane production.

The Company's realized price for natural gas was higher by 85% for the three months ended September 30, 2021 versus the comparative period. This compares to a 61% increase in the benchmark AECO price over the same period. For the majority of the Company's natural gas production, the Company receives AECO plus a slightly positive adjustment for heating content from natural gas liquids left in the natural gas stream. A portion of the Company's natural gas production which is sold in Alberta received a higher price adjustment, non AECO based, in the third quarter of

2021 than in 2020 which had a positive effect on the Company's premium to AECO in the third quarter of 2021.

On a boe basis, the Company's realized price was 83% higher for the three and nine months ended September 30, 2021 than the comparative period, due to the higher prices received for all its products, including ethane.

Revenues

Oil and natural gas sales

	Three months ended			Nine months ended		
	Sept. 30 2021	Sept. 30 2020	% Change	Sept. 30 2021	Sept. 30 2020	% Change
Oil	3,273	2,133	53	9,201	5,257	75
Natural gas liquids	2,025	850	138	5,124	2,089	145
Total liquids	5,298	2,983	78	14,325	7,346	95
Natural gas	2,490	1,388	79	7,121	3,917	82
Total sales	7,788	4,371	78	21,446	11,263	90
Per boe	40.82	22.29	83	36.65	20.06	83

Crude oil sales increased 53% in the three months ended September 30, 2021 as a decrease in oil production volumes of 15% was offset by an increase of 81% in realized oil prices.

Natural gas liquids revenues were higher by 138% in the quarter ended September 30, 2021 as production increased by 14% and realized natural gas liquids prices increased by 110%.

Natural gas revenue increased 79% in the quarter ended September 30, 2021 as 3% lower production volumes were sold at a 85% higher realized natural gas price than in the comparative quarter.

The 78% increase in oil and gas sales for the three months ended September 30, 2021 is due to lower production volumes in the quarter of 3% being sold at an average higher price received per boe of 83% than the comparative quarter.

Oil and natural gas sales for the nine months ended September 30, 2021 were 90% higher than the comparative period as a result of higher production of 5% and an average realized sales price per boe of $36.65, an increase of 83% versus the comparative period.

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

Processing income

Clearview has a working interest in natural gas processing and compression facilities at its Carstairs, 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			Nine months ended		
	Sept. 30 2021	Sept. 30 2020	% Change	Sept. 30 2021	Sept. 30 2020	% Change
Processing income	77	142	(46)	344	399	(14)
Per boe	0.40	0.72	(44)	0.59	0.71	(17)

Processing income decreased to $77 thousand for the three months ended September 30, 2021, a 46% decrease from the comparative quarter ended September 30, 2020. Processing income decreased due to negative processing income adjustments at several of the Company's processing facilities. Processing income for the nine months ended September 30, 2021 was 14% lower than the comparative period of 2020.

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 September 30, 2021.

Commencement Date	Expiry Date	Units	Volume	Underlying Commodity	Fixed Price
January 1, 2021	October 31, 2021	GJ/day	1,000	AECO 5A	$2.43
January 1, 2021	December 31, 2021	GJ/day	1,000	AECO 5A	$2.10
April 1, 2021	October 31, 2021	GJ/day	2,000	AECO 5A	$1.86
November 1, 2021	October 31, 2022	GJ/day	3,000	AECO 5A	$2.75
January 1, 2021	October 31, 2021	Bbls/day	100	Edmonton Par	$49.45
January 1, 2021	October 31, 2021	Bbls/day	100	Edmonton Par	$52.05
February 1, 2021	October 31, 2021	Bbls/day	100	Edmonton Par	$58.45
November 1, 2021	June 30, 2022	Bbls/day	250	Edmonton Par	$75.95
July 1, 2022	September 30, 2022	Bbls/day	100	Edmonton Par	$80.30
July 1, 2022	September 30, 2022	Bbls/day	150	Edmonton Par	$72.00 to $86.00*
January 1, 2021	December 31, 2021	Bbls/day	100	US WTI	$65.00**

* Contract is a costless collar

** The Company sold a call option for 2021 on 150 barrels per day at US $65.00 per barrel and transferred the value for selling the call into the financial hedge for US $58.05 per barrel in 2020.

The fair value of the financial commodity contracts outstanding as at September 30, 2021 is estimated to be a liability of $3.1 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 liability that would have been paid to 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 three months ended September 30, 2021, the Company recognized an unrealized loss of $0.4 million on its outstanding commodity contracts versus an unrealized loss of $0.5 million in the comparative quarter ended September 30, 2020. The unrealized loss in the three months ended September 30, 2021 is the difference between the fair values of the commodity contracts at September 30, 2021 and the fair values of outstanding commodity contracts at the respective prior reporting periods.

During the three months ended September 30, 2021, the Company recorded a realized loss of $1.4 million versus a realized loss of $44 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 Sept. 30 2021	Sept. 30 2020	% Change	Nine months ended Sept. 30 2021	Sept. 30 2020	% Change
Crown – oil	300	50	500	625	241	159
Crown – natural gas liquids	519	240	116	1,354	588	130
Crown – natural gas	153	84	82	477	271	76
Gas cost allowance	(341)	(332)	3	(721)	(786)	(8)
Total Crown	631	42	1,402	1,735	314	453
Freehold	135	73	85	408	217	88
Gross over-riding	170	93	83	468	255	84
Total royalties	936	208	350	2,611	786	232
Per boe	4.91	1.06	363	4.46	1.40	219

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

The Company reviews its entitlement to Gas Cost Allowance ("GCA") 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 Sept. 30 2021	Sept. 30 2020	% Change	Nine months ended Sept. 30 2021	Sept. 30 2020	% Change
Total Crown	8.1%	0.9%	800	8.1%	2.8%	189
Freehold	1.7%	1.7%	-	1.9%	1.9%	-
Gross over-riding	2.2%	2.1%	5	2.2%	2.3%	(4)
Total royalties	12.0%	4.7%	155	12.2%	7.0%	74

The overall royalty burden for the three months ended September 30, 2021 increased by 155% to a rate of 12.0% versus 4.7% for the comparative period. The increase in Crown royalties of 800% for the quarter is due to much higher prices for all products produced on Crown lands with an increase in produced volumes of natural gas liquids in the third quarter of 2021 versus the comparative period.

For the nine months ended September 30, 2021, Crown royalties increased 189% versus the comparative period. The increase is due to an 8% reduction in GCA and much higher prices received for all products produced on Crown lands. For the nine months ended September 30, 2021 freehold and gross-overriding royalties were largely unchanged and lower by 4%, respectively, versus the comparative period of 2020. The slight decrease is due to lower production volumes from the lands burdened with these royalties despite higher prices and freehold and gross overriding royalties generally being at a fixed rate.

Transportation expenses

	Three months ended			Nine months ended		
	Sept. 30 2021	Sept. 30 2020	% Change	Sept. 30 2021	Sept. 30 2020	% Change
Transportation costs	325	319	2	1,016	881	15
Per boe	1.70	1.63	4	1.74	1.57	11

Transportation expenses include trucking costs for delivery of the Company's oil production and third-party pipeline tariffs to deliver natural gas production to the purchasers at the main market hubs. During the first quarter of 2021, the Company had 67% of its natural gas volumes under firm service transportation contracts with NGTL and operators of midstream facilities that process the Company's natural gas production.

Transportation expense increased only 2% in the three months ended September 30, 2021 as a result of a decrease in production volumes of 3% on a comparative quarter basis and a 4% increase in the cost of transportation per boe.

Transportation expense per boe for the three months ended September 30, 2021 increased 4% due to an increase in trucking costs versus the comparative period while the cost of transporting the Company's natural gas production remained unchanged relative to the three months ended September 30, 2020.

For the nine months ended September 30, 2021, transportation costs per boe increased 11% versus the comparative period of 2020 contributing to a 15% increase in total costs as a result of higher production of 5% versus the comparative period of 2020.

Operating expenses

	Three months ended			Nine months ended		
	Sept. 30 2021	Sept. 30 2020	% Change	Sept. 30 2021	Sept. 30 2020	% Change
Operating costs	2,999	2,491	20	9,050	7,785	16
Per boe	15.72	12.70	24	15.47	13.87	12

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

Operating costs per boe for the three months ended September 30, 2021 were $15.72 per boe, higher by 24% than the comparative quarter of the prior year, at $12.70 per boe. This increase reflects a 20% increase in absolute operating costs compounded by a 3% decrease in production per day. The costs of some field services have begun to increase 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 nine months ended September 30, 2021 were $15.47 per boe, higher by 12% than the comparative quarter of the prior year, at $13.87 per boe. This increase reflects a 16% increase in absolute operating costs due to an increase in the cost of some 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 5% increase in production per day.

General and administrative expenses

	Three months ended			Nine months ended		
	Sept. 30 2021	Sept. 30 2020	% Change	Sept. 30 2021	Sept. 30 2020	% Change
Gross costs	609	341	79	1,753	1,347	30
Overhead recoveries	(41)	(45)	(9)	(140)	(177)	(21)
Total G&A expenses	568	296	92	1,613	1,170	38
Per boe	2.98	1.51	97	2.76	2.08	33

General and administrative costs, net of recoveries, increased 92% and 38%, respectively, in the three and nine months ended September 30, 2021 versus the comparative periods, primarily as a result of an increase in personnel costs associated with the reinstatement of salaries which had been reduced for nine months, 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 3% decrease in production volumes for the quarter resulting in a 97% increase in general and administrative expenses per boe for the three months ended September 30, 2021 versus the comparative quarter.

The higher costs of 38% in the nine months ended September 30, 2021 were offset by a 5% increase in production volumes for the quarter resulting in a 33% increase in general and administrative expenses per boe for the nine months ended September 30, 2021 versus the comparative period.

Stock based compensation

Stock based compensation is the amortization over the vesting period of the fair value of stock options and deferred share units. The Company has granted options to acquire voting common shares to directors, officers and employees to provide an incentive and retention component of the compensation plan. The Board of Directors of the Company sets 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			Nine months ended		
	Sept. 30 2021	Sept. 30 2020	% Change	Sept. 30 2021	Sept. 30 2020	% Change
Stock based compensation	34	46	(26)	153	255	(40)
Per boe	0.18	0.23	(22)	0.26	0.45	(42)

Stock based compensation expense for the three and nine months ended September 30, 2021 was lower by 26% and 40%, respectively, versus the comparative periods. The decrease in expense is primarily due to fewer options being outstanding requiring less expense being incurred over the vesting period and a reversal of stock-based compensation expense for the cancellation of 50,000 unvested options related to an officer leaving the Company in the third quarter of 2021.

During the year ended December 31, 2020, the Company cancelled 804,000 options and granted 321,600 options to directors, officers and employees at an exercise price of $1.25 per share under option.

Depletion, depreciation and impairment

	Three months ended			Nine months ended		
	Sept. 30 2021	Sept. 30 2020	% Change	Sept. 30 2021	Sept. 30 2020	% Change
Depletion	1,995	2,100	(5)	6,164	6,004	3
Depreciation	1	2	(50)	4	5	(20)
Impairment	-	-	-	-	22,300	(100)
Total	1,996	2,102	(5)	6,168	28,309	(78)
Per boe – depletion	10.46	10.72	(2)	10.53	10.69	(1)
Per boe - depreciation	-	-	-	0.01	0.01	-
Per boe - impairment	-	-	-	-	39.71	(100)
Total	10.46	10.72	(2)	10.54	50.41	(79)

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 September 30, 2021 is primarily due to lower production volumes and the reduced depletion rate for the comparative period due to net impairment expense taken in the first quarter of 2020. Production decreased 3% and the depletion rate per boe decreased by 2% resulting in an overall decrease in depletion expense of 5% versus the comparative quarter of 2020.

Depletion expense for the nine months ended September 30, 2021 increased 3% versus the comparative period, consistent with the increase in production volumes of 5% for the period and a slightly lower depletion rate per boe.

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.

Other costs (income)

	Three months ended			Nine months ended		
	Sept. 30 2021	Sept. 30 2020	% Change	Sept. 30 2021	Sept. 30 2020	% Change
Bad debt expense	-	-	-	(18)	-	100
Earned non-refundable deposit	(50)	-	100	(50)	-	100
Site rehabilitation program grant	(79)	-	100	(304)	-	100
Total	(129)	-	100	(372)	-	100
Per boe	(0.68)	-	100	(0.64)	-	100

During the three months ended September 30, 2021, the Company earned $50 thousand as a non-refundable deposit from a company interested in purchasing a property from Clearview. The acquirer was unable to complete the purchase and hence forfeited the deposit.

As of September 30, 2021, approximately $1.2 million has been awarded as grants to the Company through the Alberta Site Rehabilitation Programs and Saskatchewan Accelerated Site Closure Program to pay service companies to complete abandonment and reclamation operations. In the nine months ended September 30, 2021, the Company received $0.3 million, representing its working interest share, of $0.4 million of grant funds for abandonment and reclamation operations undertaken on 12 gross (9.3 net) wells. Remaining grants of $0.7 million are eligible to be applied to future abandonment and reclamation operations.

In the first nine months of 2021, with the grants, the Company reduced its decommissioning obligations by $0.4 million using only $0.2 million of its own cash.

Finance costs

	Three months ended			Nine months ended		
	Sept. 30 2021	Sept. 30 2020	% Change	Sept. 30 2021	Sept. 30 2020	% Change
Interest - bank debt	198	211	(6)	738	720	3
Interest rate swaps	-	13	(100)	9	24	(63)
Interest - convertible debentures	31	-	100	95	-	100
Credit facility fees and costs	5	-	100	11	42	(74)
Cash finance costs	234	224	4	853	786	9
Accretion expense (1)	154	80	93	407	198	106
Total finance costs	388	304	28	1,260	984	28
Per boe – cash finance costs	1.22	1.14	7	1.46	1.40	4
Per boe – accretion expense	0.81	0.41	98	0.70	0.35	100

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

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

Interest on bank debt in the three months ended September 30, 2021 decreased by 6% versus the comparative period. The decrease was due a lower credit spread pursuant to the Company's lending agreement entered into on December 1, 2020 and outstanding bank debt being reduced by adjusted funds flow in excess of capital expenditures.

As of September 30, 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. 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 September 30, 2021, the Company is paying 5.68% (CDOR of 0.43% plus a stamping fee of 5.25%) on guaranteed notes.

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 increased in the three and nine months ended September 30, 2021 due to the change in timing of expected abandonment expenditures.

Income taxes

The Company has concluded that it is not probable that the deferred income tax asset associated with temporary timing differences will be realized. As a result, it has not been recognized on the statement of financial position at September 30, 2021. Therefore, no deferred income tax expense or recovery has been recorded in earnings in the current period.

Clearview has no current income taxes payable and has estimated tax pools available against income of $148.5 million, including non-capital tax loss carry-forwards of $71.2 million which will expire over the years 2024 to 2039.

The Company's tax pools as at December 31, 2020 are set out below:

Nature of tax pool	%[1]	Regular	Successor[2]	Total
Canadian exploration expense (CEE)	100	170	14,257	14,427
Canadian development expense (CDE)	30	5,034	12,636	17,670
Canadian oil and gas property expense (COGPE)	10	27,057	7,243	34,300
Foreign resource expenses	10	4,456	-	4,456
Undepreciated capital cost (UCC)	25	6,447	-	6,447
Share issue costs	20	25	-	25
Non-capital losses carry forward	100	71,184	-	71,184
Total tax pools		114,373	34,136	148,509

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

Adjusted funds flow

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

	Three months ended			Nine months ended		
	Sept. 30 2021	Sept. 30 2020	% Change	Sept. 30 2021	Sept. 30 2020	% Change
Cash flow provided by (used in) operating activities	2,060	874	136	3,848	1,728	123
Add back (deduct)						
Decommissioning expenditures	177	-	100	482	53	809
Change in non-cash working capital	(737)	57	(1,393)	(250)	(251)	-
Adjusted funds flow (1)	1,500	931	61	4,080	1,530	167

(1) See non-GAAP measures

For the quarter ended September 30, 2021, cash flow from operations was $2.1 million versus $0.9 million for the comparative period of 2020. The change of 136% was primarily due to higher adjusted funds flow versus the comparative quarter offset by an increased source of working capital.

For the nine months ended September 30, 2021, cash flow from operations was $3.8 million compared to $1.7 million for the comparative period of 2020. The change of 123% was primarily due to higher adjusted funds flow versus the comparative quarter offset by higher decommissioning capital in the current year.

Adjusted funds flow increased 61% and 167% for the three and nine months ended September 30, 2021, respectively, primarily due to higher revenues from higher realized sales prices and increased production volumes more than offsetting higher operating costs, royalties and realized losses on risk management contracts.

Net loss

	Three months ended			Nine months ended		
	Sept. 30 2021	Sept. 30 2020	% Change	Sept. 30 2021	Sept. 30 2020	% Change
Net earnings (loss)	(1,101)	(1,761)	(37)	(5,300)	(27,733)	(81)
Per boe	(5.77)	(8.98)	(36)	(9.06)	(49.38)	(82)
Per share – basic	(0.09)	(0.15)	(40)	(0.45)	(2.38)	(81)
Per share – diluted	(0.09)	(0.15)	(40)	(0.45)	(2.38)	(81)

The Company incurred a net loss of $1.1 million for the three months ended September 30, 2021 compared to a net loss of $1.8 million for the comparative quarter. The decrease in the net loss for the three months ended September 30, 2021 was primarily due to higher revenues from higher realized sales prices.

Netback analysis

	Three months ended			Nine months ended		
Barrel of oil equivalent ($/boe)	Sept. 30 2021	Sept. 30 2020	% Positive (Negative)	Sept. 30 2021	Sept. 30 2020	% Positive (Negative)
Realized sales price	40.82	22.29	83	36.65	20.06	83
Royalties	(4.91)	(1.06)	(363)	(4.46)	(1.40)	(219)
Processing income	0.40	0.72	(44)	0.59	0.71	(17)
Transportation	(1.70)	(1.63)	(4)	(1.74)	(1.57)	(11)
Operating	(15.72)	(12.70)	(24)	(15.47)	(13.87)	(12)
Operating netback (2)	18.89	7.62	148	15.57	3.93	296
Realized gain (loss) – financial instruments	(7.51)	(0.22)	(3,314)	(5.02)	2.27	(321)
General and administrative	(2.98)	(1.51)	(97)	(2.76)	(2.08)	(33)
Other costs (income)	0.68	-	100	0.64	-	100
Cash finance costs	(1.22)	(1.14)	(7)	(1.46)	(1.40)	(4)
Corporate netback (2)	7.86	4.75	65	6.97	2.72	156
Unrealized gain (loss) – financial instruments	(2.19)	(2.37)	8	(4.53)	(0.89)	(409)
Stock based compensation	(0.18)	(0.23)	22	(0.26)	(0.45)	42
Depletion and depreciation	(10.46)	(10.72)	2	(10.54)	(10.70)	1
Impairment	-	-	-	-	(39.71)	100
Accretion	(0.81)	(0.41)	(98)	(0.70)	(0.35)	(100)
Net earnings (loss)	(5.77)	(8.98)	36	(9.06)	(49.38)	82

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

The Company's corporate netback for the quarter ended September 30, 2021 increased 65% to $7.86 per boe versus the comparative period. The increase is primarily due to higher revenue per boe more than offsetting higher royalties, transportation and operating costs per boe and a significant realized loss on financial instruments per boe in the current period versus the comparative period.

SUMMARY OF QUARTERLY RESULTS

Three months ended	Sep 30 2021	Jun 30 2021	Mar 31 2021	Dec 31 2020	Sep 30 2020	Jun 30 2020	Mar 31 2020	Dec 31 2019
Production								
Oil (bbl/d)	450	504	463	487	531	320	582	621
Natural gas liquids (bbl/d)	467	549	350	345	410	387	431	494
Natural gas (mcf/d)	6,942	7,233	7,715	7,443	7,143	6,058	7,716	7,859
Total (boe/d)	2,074	2,258	2,098	2,072	2,132	1,716	2,299	2,425
Financial								
Oil and natural gas sales	7,788	7,207	6,451	4,870	4,371	2,350	4,542	6,512
Adjusted funds flow (1)	1,500	978	1,602	957	931	83	516	1,271
Per share – basic	0.13	0.08	0.14	0.08	0.08	0.01	0.04	0.11
Per share – diluted	0.13	0.08	0.14	0.08	0.08	0.01	0.04	0.11
Net earnings (loss)	(1,101)	(2,527)	(1,672)	16,891	(1,761)	(2,755)	(23,217)	(5,527)
Per share – basic	(0.09)	(0.22)	(0.14)	1.45	(0.15)	(0.24)	(1.99)	(0.48)
Per share - diluted	(0.09)	(0.22)	(0.14)	1.45	(0.15)	(0.24)	(1.99)	(0.48)

(1) See non-GAAP measures.

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, 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. As a result, adjusted funds flow increased to $1.5 million ($0.13 per share) in the third quarter of 2021. The net loss for the three months ended September 30, 2021 was $1.1 million ($0.09 per 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. As a result, adjusted funds flow decreased to $1.0 million ($0.08 per share) in the second quarter of 2021. The net loss for the three months ended June 30, 2021 was $2.5 million ($0.22 per 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. As a result, adjusted funds flow increased to $1.6 million ($0.14 per share) in the first three months of 2021. The net loss for the three months ended March 31, 2021 was $1.7 million ($0.14 per 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 resulting in higher adjusted funds flow than the third quarter of 2020. 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 resulting in higher adjusted funds flow than the second quarter of 2020. The net loss for the three months ended September 30, 2020 was $1.8 million compared to $2.8 million in the previous quarter. The major difference in the net loss was the higher adjusted funds flow in the third quarter versus the second quarter of 2020.

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

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

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

LIQUIDITY AND CAPITAL RESOURCES

The full extent of the impact of COVID-19 on the Company's future financial performance is still uncertain. It will depend on future developments that are uncertain and unpredictable, including the duration and spread of COVID-19, the global roll-out of a vaccine and the continued impact of the virus on financial markets.

The Company has a contemplated capital program of $2.0 to $2.5 million for 2021, primarily of discretionary expenditures and no significant commitments. The Company's expected 2021 adjusted funds flow and credit capacity should provide the liquidity to execute this capital program.

The Company's liquidity was strengthened further during the nine months ended September 30, 2021 as net debt was reduced by $2.1 million as adjusted funds flow in excess of capital expenditures was used to repay outstanding bank debt. As a result, net debt is $11.1 million at September 30, 2021, down from $13.2 million at December 31, 2020, with the components set out below.

As at	Sept. 30, 2021	Dec. 31, 2020
Trade and other receivables	3,866	2,724
Prepaid expenses and deposits	685	640
Bank debt	(9,247)	(12,296)
Accounts payable and accrued liabilities	(4,873)	(2,767)
Decommissioning obligations	(342)	(342)
Convertible debentures	(1,204)	(1,194)
Net debt (1)	(11,115)	(13,235)

(1) See Non-GAAP measures.

Balance sheet strength and flexibility remain a priority through an even more challenging environment with the recent drop in world crude oil prices. The Company continues to proactively consider funding alternatives, including a further equity raise and/or non-core asset sales, building on the steps taken in prior years. Improved liquidity is a priority as the Company continues to evaluate strategic acquisitions during the historic low acquisition and disposition market. The Company monitors net debt as a key component of managing liquidity risk and determining capital resources available to finance future development.

As of September 30, 2021, the Company has a revolving, operating demand loan ("Operating Facility") with an Alberta based financial institution ("Lender") with a facility limit of $11.0 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 $17.25 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% at the end of the fourth year with the remaining principal outstanding due for repayment at the end of the fifth year.

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 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 3.75% to 6.75%, depending on the Debt to Funds Flow of less than 1.0 to greater than 4.0. As of September 30, 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.

Guaranteed notes are subject to the Canadian Dollar Offered Rate ("CDOR") plus a stamping fee of 4.75% to 7.75%, 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. As of September 30, 2021, the Company is paying 5.68% (CDOR of 0.43% plus a stamping fee of 5.25%) on guaranteed notes.

Under the EDC Facility, the loan is subject to an interest rate of lender prime plus a credit spread of 3.75% to 6.75%, depending on the Debt to Funds Flow of less than 1.0 to greater than 4.0. As of September 30, 2021, the Company is paying 6.70% (lender's prime rate of 2.45% plus a credit spread of 4.25%) on the EDC Facility. The Company paid and will be required to pay an upfront fee of 1.8% of the outstanding balance, annually in December to the EDC.

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 September 30, 2021, the Company's working capital ratio for purposes of the lender's working capital covenant was 2.4:1 (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 September 30, 2021 was 2.3. The Company is also required to maintain commodity swap contracts for 50% of its oil and natural gas production volumes. The Company has satisfied the requirement to contract a portion of its production volumes as per the lending agreement.

At September 30, 2021, the Company had $2.5 million of guaranteed notes, $0.5 million 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.

In November of 2021, the Company's lender completed its annual credit review. As a result of the review the Company's Operating Facility was reduced to $8.75 million, resulting in total credit capacity of $15.0 million. The next credit review is scheduled to be completed by 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.

In addition, 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 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 ninety days notice to the other party. The following is a summary of the Company's future minimum contractual obligations and commitments as of September 30, 2021.

	2021	2022	2023	2024	2025	Thereafter
Bank debt	9,247	-	-	-	-	-
Accounts payable and accrued liabilities	4,873	-	-	-	-	-
Decommissioning obligations	100	425	425	425	425	22,093
Convertible debentures	-	-	-	-	1,262	-
Gas transportation	2	4	-	-	-	-
Office lease	28	56	-	-	-	-
Total	14,250	485	425	425	1,687	22,093

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 as fair value of 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 November 18, 2021, the Company has 11,671,387 voting common shares outstanding and 518,100 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 $4.50, $5.00 and $1.25.

Vesting period	Options - $4.50	Options - $5.00	Options - $1.25	Total
Currently vested	154,000	92,500	-	246,500
Vesting in the future in the three months ending				
December 31, 2021	-		90,533	90,533
December 31, 2022	-		90,533	90,533
December 30, 2023	-		90,534	90,534
Total	154,000	92,500	271,600	518,100

For further details about the options refer to Note 10 to the financial statements as at and for the period ended September 30, 2021.

RELATED PARTY TRANSACTIONS

There were no related party transactions in the three and nine months ended September 30, 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, 2020 and December 31, 2019. Certain estimates and judgments are described in Note 2 to the audited financial statements for the periods ended December 31, 2020 and December 31, 2019.

Impact of COVID-19

In March 2020, the World Health Organization declared a global pandemic following the rapid spread of a novel strain of the coronavirus ("COVID-19"). The outbreak and subsequent measures enforced to limit the spread of the pandemic contributed to volatility in financial markets. The pandemic has adversely impacted global trade, including significantly reducing worldwide demand for oil and natural gas.

The outbreak and current market conditions have increased the complexity of estimates and assumptions used to prepare the financial statements, particularly related to recoverable amounts. There is a high degree of uncertainty regarding the estimates and assumptions used in determining recoverable amounts including future crude oil and natural gas commodity prices, foreign exchange rates, discount rates and the Company's future production of crude oil and natural gas. As the understanding of the longer-term impacts of COVID-19 develop, the estimates and assumptions used in determining the recoverable amounts could change and there could be a material financial affect in future periods.

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 1.73% 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 year ended 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 was determined based on an estimate of the fair value of the Company at the time of grant and the conversion price associated with the issuance of the convertible debentures. The estimate of volatility is based on oil and natural gas producers listed on a Canadian stock exchange.

Deferred tax assets

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

Financial instruments

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

Cash-generating units ("CGU")

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

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

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

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

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

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

NEW ACCOUNTING POLICIES

New accounting standards:

During the nine months ended September 30, 2021, there were no new accounting standards required to be adopted by the Company.

New accounting standards not yet adopted:

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 13 of the audited financial statements for the year ended December 31, 2020 for additional analysis of these risks.

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

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

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

The Company attempts to control operating risks by:

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

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

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

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

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

Non-GAAP measures

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

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

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

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

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

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

Forward-looking statements

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

Measures, conversions and acronyms

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

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

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

WTI - West Texas Intermediate is the reference price paid in U.S. dollars at Cushing, Oklahoma for crude oil of standard grade**.**

AECO – AECO is a natural gas storage facility located at Suffield, Alberta and the price of natural gas at this terminal is used as a benchmark for Canadian purposes.

API - an indication of the specific gravity of crude oil measured on the API gravity scale. Liquid petroleum with a specified gravity of 28° API or higher is generally referred to as light crude oil.

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

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

Clearview Resources Ltd.
2400, 635 8th Avenue SW
Calgary, AB, T2P 3M3
Telephone 403-265-3503

Directors
Lindsay R. Stollery, Board Chair
Richard G. Carl
Todd L. McAllister
Harold F. Pine
Murray K. Scalf
David M. Vankka
Tim S. Halpen

Officers and Management
Tony Angelidis, President and Chief Executive Officer
Brian Kohlhammer, VP Finance and Chief Financial Officer
Renee Miles, Land Manager
Dmitriy Shlyonchik, Operations Manager
Lynda Christie, Controller

Reserves Evaluator
McDaniel & Associates Consultants Ltd.
2200, 255 – 5th Avenue SW
Calgary, AB, T2P 3G6

Auditors
KPMG LLP
Suite 3100, 205 - 5th Avenue SW
Calgary, AB, T2P 4B9

Lender
ATB Financial
600, 585 – 8th Ave SW
Calgary, AB, T2P 1G1

Legal Counsel
Dentons Canada LLP
1500, Bankers Court, 850 – 2nd Street SW
Calgary, AB, T2P 0R8

Transfer Agent
Computershare
11th Floor, South Tower, 100 University Avenue
Toronto, ON, M5J 2Y1