CLEARVIEW RESOURCES LTD

Clearview Resources Ltd.

Management Discussion and Analysis (MD&A)

March 31, 2018

STRATEGY OF THE COMPANY

Over the past fiscal year, the Company continued to transform from a non-operated producer into a growth-oriented, light oil focused operator of a majority of its production. Building on the properties acquired in the Greater Pembina area late in the fourth quarter of the prior year, the Company focused on integrating the newly acquired assets with its legacy assets. This resulted in the following:

- completed optimization work on the newly acquired assets to increase production to over 2,100 boe/d for the last three quarters of the year;
- reduced costs on a per boe basis in several areas of the Company's operations and corporate structure to improve the operating and corporate netback per boe;
- funded the field capital program (excluding acquisitions) from internally generated adjusted funds flow;
- acquired a 50% working interest in a light oil prospect at Windfall, Alberta in the fourth quarter;
- initiated the planning and process to drill the Company's first operated light oil well at its Wilson Creek, Alberta property;
- initiated the planning and process to drill the Company's first operated light oil well at its Windfall, Alberta property;
- maintained strong lending values to support the Company's credit facility;
- maintained an appropriate debt versus equity capital structure;
- established a management incentive plan consistent with growing shareholder value;
- maintaining a current licensee liability rating of 2.7, providing the Company with the ability to transact on further acquisition opportunities; and
- continued to evaluate non-core assets for potential dispositions to fund the capital program.

During the fourth quarter of the fiscal year, the Company initiated several strategic transactions to further transform the Company. On April 10, 2018, the Company closed the disposition of a light oil property located in southern Alberta for $3,369,000. The Company sold the property for approximately $53,500 per flowing boe/d. The proceeds from the disposition were immediately applied against the Company's bank debt to further improve its financial flexibility towards funding the Company's upcoming summer drilling program. This property had been reclassified to assets held for sale in the statement of financial position as of March 31, 2018.

Also, in the fourth quarter of 2018, the Company initiated discussions with its joint venture partner and the operator of its newly acquired Windfall property. On April 16, 2018, the Company closed the acquisition of Bashaw Oil Corp. ("Bashaw") through a share for share exchange based on 25.379 common shares of Bashaw for one voting common share of the Company. Clearview issued 1,560,046 voting common shares to the shareholders of Bashaw. The Company acquired the remaining 50% working interest at Windfall and increased its financial flexibility resulting from the cash and working capital surplus position of Bashaw.

As part of the Bashaw merger, the Board of Directors of Clearview effected a change in management with an emphasis on current operational excellence and expertise in horizontal drilling and completions using multi-stage fracing technology.

The proceeds from the disposition and the positive cash position from the acquisition of Bashaw have strategically positioned the Company for the commencement of operated, light oil development drilling activity in the second half of 2018. In addition, Clearview continues to pursue its growth strategy within its focus area of west central Alberta, including asset or corporate acquisitions, production optimization and non-core dispositions towards increasing shareholder value on a cash flow and net asset value per share basis.

HIGHLIGHTS FOR THE YEAR ENDED MARCH 31, 2018

- Increased production through optimization projects for the last three quarters of the year to 2,115 boe/d compared to 1,992 boe/d for the first quarter ended June 30, 2017.

- Realized sales price was $26.30 per boe compared to $29.39 per boe in the prior year, a decrease of 11%, while the fourth quarter of 2018 was down 6% to $31.98 per boe due to lower natural gas prices.

- Operating costs were $14.69/boe for the year ended March 31, 2018, compared to $19.46/boe, down 25%, while the fourth quarter of the current and prior year were $15.32/boe and $16.96/boe, respectively, down 10%.

- General and administrative costs were $2.87/boe for the year ended March 31, 2018, compared to $5.26/boe, down 45%, while the fourth quarter of the current and prior year were $4.66/boe and $7.17/boe, respectively, down 35%.

- Cash finance costs were $1.27/boe for the year ended March 31, 2018, compared to $1.79/boe, down 29%, while the fourth quarter of the current and prior year were $1.27/boe and $2.24/boe, respectively, down 43%.

- Corporate netback increased by 385% to $4.78 per boe for the current fiscal year versus a loss of $1.68 per boe in the prior fiscal year.

- Acquired a 50% working interest in an Alberta light oil property (Windfall) in the Greater Pembina core area in January 2018; existing production net to Clearview is 55 bbls/d of light oil and liquids plus 330 mcf/d of natural gas; future development will focus on light oil targets with up to 16 gross (8 net) locations planned of which 1 gross well is planned for later in 2018.

- Successfully acquired 16.25 gross (16.25 net) sections contiguous to existing lands in the Greater Pembina core area, at an average cost of approximately $22,000 per section.

Clearview Resources Ltd.
Management Discussion and Analysis (MD&A)
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The management discussion and analysis ("MD&A") is a review of the financial position and results of operations of the Company for the three and twelve months ended March 31, 2018 and 2017 and should be read in conjunction with the Company's audited financial statements and accompanying notes for the years ended March 31, 2018 and 2017. The audited financial statements have been prepared in accordance with International Financial Reporting Standards ("IFRS") as issued by the International Accounting Standards Board. Unless otherwise noted, all dollar amounts 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 June 28, 2018.

Refer to page 25 for information about non-GAAP measures, page 26 for information on forward-looking statements and page 27 for measures, conversions and acronyms used in the MD&A.

OVERVIEW OF THE COMPANY

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

The Company's objectives are to:

- acquire long life, cash generating oil and natural gas properties with growth potential, and
- maintain a low cost and financially robust structure.

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

Region - Alberta	Property	Primary production	P+P Reserves[1]	Average WI	Operatorship[3]
Greater Pembina	Northville[2]	Liquids rich natural gas	5,800	87%	Yes
	Pembina[2]	Liquids rich natural gas	1,544	80%	Yes
	Wilson Creek[2]	Light oil and liquids rich natural gas	3,766	60%	Yes
	Lindale (Unit)	Light oil with associated natural gas and liquids	423	10.6%	No
	Windfall	Light oil	2,118	50.0%	No
Other	Bantry	Medium oil	501	40.0%	No
	Caribou[2]	Light oil	408	63.3%	Yes
	Carstairs (Unit)	Liquids rich natural gas	562	17.0%	No
	Carmangay	Light oil	197	19.1%	No
	Crossfield (Unit)	Liquids rich natural gas	119	4.2%	No
	Warburg (Unit)	Light oil	29	3.8%	No
	Caroline (Unit)	Liquids rich natural gas	9	0.2%	No
	Miscellaneous	Various	11	Various	Mixed
Total			15,487		

[1] mboe of total proved plus probable reserves at March 31, 2018 as determined by the independent reserves evaluator, GLJ Petroleum Consultants Ltd.

[2] Acquired in the quarter ended March 31, 2017 except for approximately 17% of the Wilson Creek reserves

[3] Operatorship of a majority of the property

SELECTED ANNUAL INFORMATION

	Three months ended March 31		Year ended March 31		
	2018	2017	2018	2017	2016
Oil and natural gas sales	6,171	2,279	20,286	7,112	8,309
Adjusted funds flow (1)	429	223	3,679	(408)	2,018
Per share – basic	0.05	0.05	0.44	(0.10)	0.65
Per share – diluted	0.05	0.05	0.44	(0.10)	0.65
Net earnings (loss)	(3,879)	1,031	(8,460)	(1,896)	(1,345)
Per share – basic	(0.46)	0.21	(1.00)	(0.48)	(3.66)
Per share – diluted	(0.46)	0.21	(1.00)	(0.48)	(3.66)
Total assets			72,714	71,156	33,105
Total long term liabilities			18,873	15,607	7,358
Working capital deficiency			15,285	14,568	11,362
Net debt			14,154	14,604	11,315
Total capital expenditures - net	3,919	30,615	6,375	28,706	1,417

1 See non-GAAP measures

The Company experienced significant growth in oil and natural gas sales and adjusted funds flow following the acquisition of producing oil and gas properties in the fourth quarter of the prior fiscal year and the acquisition of a light oil property in the fourth quarter of the current fiscal year. Increased oil and natural gas liquids prices also contributed to the improvement in adjusted funds flow but declining natural gas prices reduced the positive effect of increased natural gas production. The net loss was also impacted by these factors in addition to increased depletion, an impairment in the current year of $1,404 and unrealized losses on commodity contracts. Long term liabilities have increased as a result of additional decommissioning obligations associated with the acquisitions while the working capital deficiency has increased as capital expenditures have been greater than adjusted funds flow and equity raised to fund the acquisitions.

DISCUSSION OF OPERATIONS

Capital expenditures

	Three months ended March 31			Year end March 31		
	2018	2017	% Change	2018	2017	% Change
Land	101	-	100	354	-	100
Drilling, completions, equipping	357	699	(49)	1,947	781	149
Facilities	104	134	(22)	559	153	265
Other	(13)	-	100	139	-	100
Capital invested	549	833	(34)	2,999	934	221
Disposition of properties	-	-	-	-	(2,010)	(100)
Net capital invested	549	833	(34)	2,999	(1,076)	(379)
Acquisition of properties	3,370	29,782	(89)	3,376	29,782	(89)
Total capital expenditures	3,919	30,615	(87)	6,375	28,706	(78)

Three (0.32 net) oil wells were drilled at Lindale in March 2017 of which two commenced production in April 2017 and the third commenced production in August 2017. Net capital costs for the three wells were approximately $926 of which $313 was incurred in the year ended March 31, 2018.

The Company participated in Crown land sales in the year ended March 31, 2018, investing $352 to acquire 16.25 gross (16.25 net) acres at an average price of approximately $22/section. The acquired land and mineral rights are immediately adjacent to existing lands in the Greater Pembina core area.

Total capital expenditures for the year ended March 31, 2018 were $6,375 comprised of the following:

Nature	Property	Objective	Cost
Land	Greater Pembina Core Area	Acquire mineral rights	352
Geological	Greater Pembina Core Area	Develop low risk growth opportunities	85
DCET[1]	Lindale Cardium Unit	Complete the 3 well drilling programs	313
Optimization	Caribou	Enhance production from low producing wells	485
Optimization	Northville, Pembina	Enhance production from low producing wells	357
Optimization	Wilson Creek	Enhance production from low producing wells	51
Water flood	Lindale Cardium Unit	Initial steps for enhanced secondary recovery	388
Facilities/waterflood	Carmangay	Gathering system and related facilities	226
Facilities	Northville, Pembina	Compressor overhauls and turnarounds	261
Acquisitions	Windfall	50% working interest in light oil property	3,376
Optimization	Windfall	Enhance production from low producing wells	134
Other	Various	Capital maintenance	347
Total			6,375

[1] Drill, complete, equip and tie in a new well

The Company continues its planning, analysis and preparation for the drilling of an operated horizontal well at its Wilson Creek property targeting the Cardium formation (light oil) and at its Windfall property targeting a Bluesky/Gething channel (light oil). The Company expects to kick off its first drilling operation later in the summer assuming, among other things, the availability of a drilling rig and weather permits access to the locations.

The Company also may participate in development opportunities proposed by operating partners, subject to satisfactory technical and economic analysis.

Production

Production is summarized in the following table:

	Three months ended March 31			Year end March 31		
	2018	2017	% Change	2018	2017	% Change
Oil – bbl/d	498	243	105	437	240	82
Natural gas liquids – bbl/d	450	130	246	474	103	360
Total liquids – bbl/d	948	373	154	911	343	166
Natural gas – mcf/d	7,175	2,223	223	7,211	1,919	276
Total – boe/d	2,144	744	188	2,113	663	219

Production for the quarter ended and year ended March 31, 2018 increased by 188% and 219% over the respective comparative periods due to the acquisition of properties in the fourth quarter of the prior year, new wells brought on production from the drilling program at Lindale and optimization work undertaken during the year. In the fourth quarter ended March 31, 2018, the Company also acquired light oil with associated natural gas production of approximately 116 boe/d for the quarter.

Production, on a boe/d basis, from these acquired properties was as follows:

	Three months ended March 31			Year end March 31		
	2018	2017	% Change	2018	2017	% Change
Wilson Creek	395	331	19	431	177	144
Northville, Pembina and Caribou	1,230	-	100	1,238	-	100
Lindale	89	82	9	102	108	(6)
Windfall	116	-	100	29	-	100
Total – boe/d	1,830	413	343	1,800	285	532
% of total production	85%	56%	52	85%	43%	98

Clearview's production portfolio for the quarter ended March 31, 2018 was weighted 23% to oil, 21% to natural gas liquids and 56% to natural gas. For the year ended March 31, 2018 the production mix was weighted 21% to oil, 22% to natural gas liquids and 57% to natural gas. 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 March 31			Year end March 31		
	2018	2017	% Change	2018	2017	% Change
Oil – Edmonton light ($/bbl)	70.09	64.83	8	63.16	58.70	8
Oil – Hardisty Bow River ($/bbl)	49.08	49.72	(1)	50.10	44.99	11
Differential – Medium oil ($/bbl)	21.01	15.10	39	13.06	13.71	(5)
NGLs - Pentane ($/bbl)	80.30	69.28	16	69.96	61.70	13
NGLs – Butane ($/bbl)	48.39	44.53	9	45.04	38.12	18
NGLs – Propane ($/bbl)	33.02	28.81	15	29.79	19.02	57
Natural gas – AECO ($/mcf)	2.06	2.69	(23)	2.05	2.39	(14)
Exchange rate – US$/CAD$	0.7908	0.7558	5	0.7800	0.7620	2

Benchmark prices

The refiners' posted prices are influenced by the WTI reference price, transportation capacity and costs, US$/CAD$ exchange rates and the supply/demand situation of particular crude oil quality streams during the period. Benchmark oil and natural gas liquids prices have performed reasonably well in the fourth quarter of 2018 with butane and propane showing significant gains. The Q4 2018 differential between light and medium gravity oil was $21.01/bbl compared to the same quarter of 2017 at $15.10/bbl. Conversely, natural gas prices continue to be low. Benchmark natural gas prices in the first quarter of the year averaged $2.79/mcf but declined significantly through the summer and fall before recovering in the fourth quarter of 2018 to $2.06/mcf.

The Company has benefited from the higher prices for oil and liquids, particularly the increase in butane and propane prices. The benchmark price for butane in the three months ended March 31, 2018 is $48.39/bbl compared to $44.53/bbl in the same quarter of the prior year. Similarly, propane was $33.02/bbl in the three months ended March 31, 2018 compared to $28.81/bbl in the comparative period of the prior year.

Realized sales prices

	Three months ended March 31			Year end March 31		
	2018	2017	% Change	2018	2017	% Change
Oil – $/bbl	63.66	54.71	16	58.62	49.01	20
NGLs – $/bbl	37.37	37.51	-	32.68	32.51	1
Natural gas – $/mcf	2.71	2.66	2	1.98	2.22	(11)
Total – $/boe	31.98	34.03	(6)	26.30	29.39	(11)

Realized prices
Realized prices vary from the benchmark prices largely due to quality differences including differences for density and sulphur. Bantry produces medium gravity oil while all other oil production is light oil. Medium gravity oil realizes a lower price than light oil. The differential can vary considerably from quarter to quarter. Despite the increase in the benchmark liquids prices, the acquired properties have considerable ethane production, 15% of the total liquids production, as a result of going through a deep cut processing facility. Ethane is more correlated to natural gas prices. Hence the total natural gas liquids price has been reduced by the much lower price received for the ethane. Consequently, the average natural gas liquids price was virtually unchanged from the comparative fourth quarter and for the full year. The Company's realized price for natural gas in the summer and fall was much lower at $1.40/mcf and $1.24/mcf, than the respective benchmark prices of $1.72/mcf and $1.61/mcf, respectively for the second and third quarters of the fiscal year, due to pipeline constraints affecting the Greater Pembina core area in those periods.

Revenue

Oil and natural gas sales

	Three months ended March 31			Year end March 31		
	2018	2017	% Change	2018	2017	% Change
Oil	2,853	1,199	138	9,345	4,291	118
Natural gas liquids	1,566	549	185	5,740	1,268	353
Total liquids	4,419	1,748	153	15,085	5,559	171
Natural gas	1,752	531	230	5,201	1,553	235
Total sales	6,171	2,279	171	20,286	7,112	185
Per boe	31.98	34.03	(6)	26.30	29.39	(11)

Crude oil sales increased 138% in the fourth quarter ended March 31, 2018 compared to the same quarter of the prior year and increased 118% for the year ended March 31, 2018 compared to the prior year. Growth in oil sales was due to a combination of higher production volumes, relating primarily to the acquisitions completed in the prior year, and higher prices received for the Company's production. While oil production represented 21% of the production volumes for the year, oil sales represented 46% of total oil and natural gas sales.

Natural gas liquids revenue increased 185% in the quarter ended March 31, 2108 versus the comparative quarter and increased 353% in the current fiscal year as compared to the prior year. Similar to oil sales, increased revenue from natural gas liquids was a result of higher production volumes and higher prices received for those volumes sold. Natural gas liquids generated 28% of total oil and natural gas sales but represented 22% of the production volumes for the year.

Natural gas revenue increased 230% in the quarter ended March 31, 2108 versus the comparative quarter and increased 235% in the current fiscal year as compared to the prior year. Increased revenue from natural gas was a result of higher production volumes more than offsetting a decrease in the price received for the natural gas volumes sold. Natural gas generated 26% of total oil and natural gas sales but represented 57% of the production volumes for the year.

Processing income

Clearview has a working interest in natural gas processing and compression facilities at its Caroline, Carstairs, Crossfield, Wilson Creek and Northville properties. The capital expenditures to acquire the working interests in these facilities is included in property, plant and equipment on the statement of financial position. The Company earns processing fees on third party production volumes processed through these facilities on a fee for service arrangement. Management of the Company considers processing income to be a recovery of costs to operate these facilities when calculating operating costs on a per boe basis.

Processing income increased to $810 for the year ended March 31, 2018, a 19% increase over the prior year. The increase in processing income for the year was due to additional processing of third party volumes at its Wilson Creek property and fees for compression at its Northville property. For the three months ended March 31, 2018 the Company earned $241 in processing income, an increase of 29% over the same quarter of the prior year. The increase in the fourth quarter was primarily attributable to additional processing income being earned at Wilson Creek and Northville.

	Three months ended March 31			Year end March 31		
	2018	2017	% Change	2018	2017	% Change
Processing income	241	187	29	810	680	19
Per boe	1.25	2.80	(55)	1.05	2.81	(63)

Risk management activities

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

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 the statement of operations.

The following table lists the financial commodity contracts held by the Company that were outstanding as of March 31, 2018:

Commencement Date	Expiry Date	Units	Volume	Underlying Commodity	Fixed Price
Jan. 1, 2018	Dec. 31, 2018	bbls/d	100	NYMEX WTI CDN	$65.00
Jan. 1, 2018	Dec. 31, 2018	bbls/d	100	NYMEX WTI CDN	$67.25
Jan. 1, 2018	Dec. 31, 2018	bbls/d	100	NYMEX WTI CDN	$70.00

The fair value of the financial contracts outstanding as at March 31, 2018 is estimated to be a liability of $1,131. 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 year ended March 31, 2018, the Company recognized an unrealized loss of $1,167 on its outstanding commodity contracts versus an unrealized gain in the prior year of $83. In the three months ended March 31, 2018, Clearview recorded an unrealized loss on commodity contracts of $458 as compared to an unrealized gain of $36 in the three months ended March 31, 2017. The unrealized loss in the fourth quarter and fiscal year is the difference between the fair values of the commodity contracts at March 31, 2018 and the fair values at the respective prior reporting period.

For the year ended March 31, 2018, the Company had a realized gain on commodity contracts of $568 versus a realized loss in the prior year of $274. During the fourth quarter, the Company incurred a realized loss on commodity contracts of $307 as compared to a realized gain of $19.

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

Royalties

	Three months ended March 31			Year end March 31		
Amount	2018	2017	% Change	2018	2017	% Change
Crown – oil	284	22	1,191	626	94	566
Crown – natural gas liquids	406	80	408	1,567	260	503
Crown – natural gas	138	58	138	545	114	378
Gas cost allowance	(337)	(66)	411	(1,598)	(421)	280
Total Crown	491	94	422	1,140	47	2,326
Freehold	142	117	21	579	579	-
Gross over-riding	158	60	163	570	192	197
Total royalties	791	271	192	2,289	818	180
Per boe	4.10	4.05	1	2.97	3.38	(12)

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

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

	Three months ended March 31			Year end March 31		
Royalty rate	2018	2017	% Change	2018	2017	% Change
Total Crown	7.9%	4.1%	93	5.6%	0.7%	700
Freehold	2.3%	5.1%	(55)	2.9%	8.1%	(64)
Gross over-riding	2.6%	2.6%	-	2.8%	2.7%	4
Total royalties	12.8%	11.8%	8	11.3%	11.5%	(2)

The overall royalty burden for the fiscal year decreased by 2% to a rate of 11.3% versus 11.5% for the prior year. The increase in royalty rate for the three months ended March 31, 2018 of 8% is primarily due to the higher royalty rates associated with the new properties acquired last year and also the higher prices received for production which increases the royalty rate due to the sliding scale nature of the calculation.

Transportation expenses

	Three months ended March 31			Year end March 31		
	2018	2017	% Change	2018	2017	% Change
Transportation costs	687	110	525	1,070	256	318
Per boe	3.56	1.64	117	1.39	1.06	31

Transportation expenses include trucking costs for delivery of the Company's oil production and third-party pipeline tariffs to deliver production to the purchasers at the main market hubs. Transportation expense increased by 31% to $1.39 per boe for the year as a result of higher transportation costs associated with the acquisitions undertaken in the fourth quarter of the prior fiscal year and the fourth quarter of the current fiscal year.

In the three months ended March 31, 2018, the Company's transportation costs were higher due to the significantly higher production volumes from the acquisitions in the fourth quarter of the prior year. On a production month basis, transportation costs for the three months ended March 31, 2018 were $1.54 per boe.

Operating expenses

	Three months ended March 31			Year end March 31		
	2018	2017	% Change	2018	2017	% Change
Operating costs	2,956	1,135	160	11,334	4,710	141
Per boe	15.32	16.96	(10)	14.69	19.46	(25)

The Company has focused on reducing production costs given the prolonged period of low oil and natural gas prices. However, some components of operating an oil and natural gas property are essentially fixed, e.g. property taxes, lease rentals.

The Company's plans for optimization of production from existing wells (particularly on the properties acquired in the prior year) was comprised of a mix of capital and operating projects, e.g. acquisition and installation of a new pump was capitalized whereas the repair of a pump was an operating cost. Most of these costs were incurred in the second and third quarter as the objective was to complete the projects in advance of winter weather conditions. These projects drove the higher production after the first quarter of the fiscal year (average 2,115 boe/d) compared to 1,992 boe/d in the first quarter of the year. It is estimated that all workover costs will be recovered within one year with a significant portion recovered by March 31, 2018.

Operating costs for the three months ended March 31, 2018 were $15.32 per boe, lower, by 10%, than the comparative quarter of the prior year, at $16.96/boe. The lower costs per unit are a combination of the following: the shift in production mix to a greater natural gas weighting of 56% in the three months ended March 31, 2018 as compared to 50% in the fourth quarter of the prior year; the economies of scale of higher production and a strong focus on cost control. Natural gas production costs per unit are generally expected to be lower than oil production costs per unit.

The Company's continues to reduce production costs. In January 2018, gas flows within the Wilson Creek property were modified, which allowed the shut down of two operated compressor stations. Third party processing fees will be reduced and the operating costs of the two compressor stations will be eliminated.

General and administrative expenses

	Three months ended March 31			Year end March 31		
	2018	2017	% Change	2018	2017	% Change
Gross costs	969	494	96	2,487	1,296	92
Overhead recoveries	(69)	(15)	360	(272)	(23)	1,083
Total G&A expenses	900	479	88	2,215	1,273	74
Per boe	4.66	7.15	(35)	2.87	5.26	(45)

General and administrative costs increased 96% in the fourth quarter of the year primarily due to termination payments to several officers and employees of the Company. For the year ended March 31, 2018 costs were higher by 92% due to the costs of moving to new office space, the transition of personnel from consultants to employees and bad debt expense of $56. Higher personnel costs were also incurred as the Company required additional staff due to the Company's growth through acquisitions in the fourth quarter of the prior year. Overhead recoveries increased in the year as a result of being an operator of more production and the ability to invoice working interest partners for administrative functions in accordance with industry standards.

General and administrative costs per boe decreased 45% in the year compared to the prior year, as a result of its cost structure relative to the Company's production volumes.

Stock based compensation

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

The first round of options granted in June and August 2016 expire 7 years from the date of grant and vest one third immediately and one third on each of the first and second anniversaries. Subsequent grants also expire 7 years from the date of grant but vest one third on each of the first, second and third anniversaries. During the current year, the Company granted options to acquire 325,000 voting common shares with an exercise price of $5.00 per share under option, with expiration and vesting as described above. A further 7,500 options under the same terms and conditions were granted to a new employee who commenced employment in December 2017. The assumptions used in determining the fair values are as follows:

Years ended March 31	2018	2017
Exercise price	$5.00	$4.50
Volatility	73%	73%
Expected option life	7.0 years	7.0 years
Dividend	$nil	$nil
Risk-free interest rate	0.5%	0.5%

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

	Three months ended March 31			Year end March 31		
	2018	2017	% Change	2018	2017	% Change
Stock based compensation	224	203	10	938	735	28
Per boe	1.16	3.03	(62)	1.22	3.04	(60)

Stock based compensation expense for the year ended March 31, 2018 amounted to $938 compared to $735 in the prior year. The increase is due to additional employees and the stock options granted during the year.

Depletion, depreciation and impairment

	Three months ended March 31			Year end March 31		
	2018	2017	% Change	2018	2017	% Change
Depletion	2,119	947	124	8,265	2,764	199
Depreciation	7	-	100	7	-	100
Impairment	1,404	738	90	1,404	738	90
Total	3,530	1,685	109	9,676	3,502	176
Per boe – depletion	10.98	14.14	(22)	10.71	11.42	(6)
Per boe - depreciation	0.04	-	100	0.01	-	100
Per boe - impairment	7.27	11.02	(34)	1.82	3.05	(40)
Total	18.29	25.16	(27)	12.54	14.47	(13)

The Company calculates depletion on property, plant and equipment using the unit-of-production method based on proved plus probable reserves. Depreciation is calculated based on the useful lives of office equipment and furniture. The increase in depletion for the three months ended and year ended March 31, 2018 is due to significantly greater production volumes partially offset by the benefit of a lower depletion rate. Production increased 188% and 219% for the quarter and year ended March 31, 2018, while the depletion rate decreased by 22% and 6% for the three months and year ended March 31, 2018.

At March 31, 2018, Clearview evaluated its property, plant and equipment for indicators of any potential impairment or related reversal. As a result of this assessment, management determined that no impairment or reversal of impairment calculation was necessary for the year. An impairment test was conducted on an oil property of the Company prior to it being reclassified to assets held for sale. Based on the fair value less costs to sell of the property, an impairment charge to expense of $1,404 was recorded by the Company in the current year. The property was sold subsequent to the end of the fiscal year.

Impairment tests were necessary at March 31, 2017, which resulted in net impairment expense of $738 based on the information in the following table:

	Year ended March 31, 2017			
Cash generating unit	Recoverable amount[1]	Net Impairment	Test methodology	Discount rates[2]
Central Alberta Gas CGU	49,464	(1,288)	VIU	10%-20%
Central Alberta Oil CGU	8,381	2,076	VIU	10%-20%
Southern Alberta Oil CGU 1	4,858	(1,530)	FVLCTS	10%-20%
Southern Alberta Oil CGU 2	2,588	1,480	FVLCTS	10%-20%
Total	65,291	738		

[1] Recoverable amount is net of asset retirement obligations based on value in use or fair value less costs to sell.
[2] Discount rates vary between reserve categories based on risk and other factors.

Transaction costs

	Three months ended March 31			Year end March 31		
	2018	2017	% Change	2018	2017	% Change
Transaction costs	96	117	(18)	96	436	(78)
Per boe	0.50	1.75	(71)	0.12	1.80	(93)

Transactions costs for the quarter and year ended March 31, 2018 were lower by 18% and 78%, respectively, as compared to the same periods of the prior year. The reduction in transaction costs was due to a much smaller acquisition in the fourth quarter of 2018 than the size of the acquisitions in the comparative quarter. The Company also incurred some costs associated with the subsequent event to acquire Bashaw Oil Corp. as described in the “Proposed Transactions” section of the MD&A.

Finance costs

	Three months ended March 31			Year end March 31		
	2018	2017	% Change	2018	2017	% Change
Interest on bank debt	238	66	261	828	256	223
Credit facility fees and costs	8	84	(90)	153	177	(14)
Cash finance costs	246	150	64	981	433	127
Accretion expense (1)	96	40	140	358	133	169
Total finance costs	342	190	80	1,339	566	137
Per boe – cash finance costs	1.27	2.24	(43)	1.27	1.79	(29)
Per boe – accretion expense	0.50	0.60	(17)	0.46	0.55	(16)

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

Cash finance costs include interest on bank debt and lender fees plus minor amounts for miscellaneous interest and penalties charged by vendors and taxing authorities. Interest on bank debt increased during the year due to increases in the bank prime lending rate during the year and higher average outstanding debt balances after funding the acquisitions at the end of the prior year.

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

- July 2016 - from 3.70% to 5.70% - increase in credit spread to 3% over prime,
- July 2017 - from 5.70% to 5.95% - increase in the prime rate,
- September 2017 - from 5.95% to 6.20% - increase in the prime rate, and
- January 2018 - from 6.20% to 6.45% - increase in the prime rate.

The average rate for prime based borrowings during the year ended March 31, 2018 was 6.7%, inclusive of standby fees.

The Company also has the option of borrowing using the lender’s guaranteed notes which are subject to a current stamping fee of 4.0% per annum plus the guaranteed note rate for 30, 60, 90 and 180 day terms. Guaranteed notes resulted in an average rate of approximately 5.3% during the year ended March 31, 2018.

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 2 to 55 years due to the long-term nature of certain assets. Accretion expense increased in both the fourth quarter and year ended March 31, 2018, compared to the prior respective periods, due to a higher decommissioning liability and higher risk-free interest rates used to calculate the accretion expense.

Income taxes

	Three months ended March 31			Year end March 31		
	2018	2017	% Change	2018	2017	% Change
Deferred income tax recovery	-	729	(100)	-	729	(100)
Per boe	-	10.88	(100)	-	3.01	(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 at March 31, 2018. Therefore, no deferred income taxes have been charged against earnings in the current year. In the year ended March 31, 2017, a deferred income tax recovery of $729 was recorded which related to an acquisition of oil and natural gas assets in the fourth quarter of the prior year.

Clearview has no current income taxes payable and has estimated tax pools available against income of $90,729, including non-capital tax loss carry-forwards of $36,698 which will expire over the years 2026 to 2038. The Company’s tax pools as at March 31, 2018 are set out below:

Nature of tax pool	%[1]	Regular	Successor[2]	Total
Canadian exploration expense (CEE)	100	126	14,378	14,504
Canadian development expense (CDE)	30	2,824	19,879	22,703
Canadian oil and gas property expense (COGPE)	10	34,686	8,883	43,569
Foreign resource expenses	10	6,601	-	6,601
Undepreciated capital cost (UCC)	25	9,605	-	9,605
Share issue costs	20	189	-	189
Non-capital losses carry forward	100	36,340	-	36,340
Total tax pools		90,371	43,140	133,511

[1] The percentage rate shown is the maximum rate of deduction.

[2] The successor pools were acquired with one of the acquisitions in March 31, 2017 and can be deducted only against future profits attributable to the acquired properties.

Adjusted funds flow

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

	Three months ended March 31			Year end March 31		
	2018	2017	% Change	2018	2017	% Change
Cash flow provided by (used in) operating activities	1,932	(980)	(297)	4,337	(983)	(541)
Add back (deduct)						
Decommissioning expenditures	122	-	100	223	-	100
Change in non-cash working capital	(1,625)	1,203	(235)	(881)	575	(253)
Adjusted funds flow 1	429	223	92	3,679	(408)	(1,002)

[1] See non-GAAP measures

Cash flow from operations increased for the three months and year ended March 31, 2018 to $1,932 and $4,337, respectively, from cash flow used in operations of $980 and $983 for the comparative periods of the prior year. The increase in cash flow from operations was primarily due to increased production from the acquisitions closed in the fourth quarter of the prior year.

Adjusted funds flow for the fourth quarter ended March 31, 2018 was $429 compared to $223 for the comparative period of the prior year. For the year ended March 31, 2018 adjusted funds flow was $3,679 compared to negative adjusted funds flow of $408 for the year ended March 31, 2017. The significant increase in adjusted funds flow for the year ended March 31, 2018 was due to increased production from the acquisitions in the fourth quarter of the prior year. Operating costs, general and administrative expenses, transaction costs and cash finance costs all trended lower on a per boe basis from the prior year. Adjusted funds flow differs from cash flow from operations due to the exclusion of decommissioning expenditures and changes in non-cash working capital.

Net loss

	Three months ended March 31			Year end March 31		
	2018	2017	% Change	2018	2017	% Change
Net earnings (loss)	(3,879)	1,031	(476)	(8,460)	(1,896)	346
Per boe	(20.09)	15.39	(231)	(10.95)	(7.84)	40
Per share – basic	(0.46)	0.21	(316)	(1.00)	(0.48)	111
Per share – diluted	(0.46)	0.21	(316)	(1.00)	(0.48)	111

The Company sustained net losses of $3,879 and $8,460 for the three months and year ended March 31, 2018, respectively, compared to net earnings of $1,031 and a net loss of $1,896 for the comparative periods.

The increase in net loss for the year ended March 31, 2018 was primarily due to increased depletion from increased production volumes, an impairment of $1,404 related to an asset held for sale and an unrealized loss on commodity contracts of $1,167. The prior year also included a gain on acquisition and disposition of assets for $2,799 including deferred taxes.

Netback analysis

Barrel of oil equivalent ($/boe)	Three months ended March 31 2018	2017	% Positive (Negative)	Year end March 31 2018	2017	% Positive (Negative)
Realized sales price	31.98	34.03	(6)	26.30	29.39	(11)
Royalties	(4.10)	(4.05)	(1)	(2.97)	(3.38)	12
Processing income	1.25	2.80	(55)	1.05	2.81	(63)
Transportation	(3.56)	(1.64)	(117)	(1.39)	(1.06)	(31)
Operating	(15.32)	(16.96)	10	(14.69)	(19.46)	25
Operating netback	10.25	14.18	(28)	8.30	8.30	-
Realized gain (loss) – commodity contracts	(1.59)	0.29	(648)	0.74	(1.13)	165
General and administrative	(4.66)	(7.15)	35	(2.87)	(5.26)	45
Transaction costs	(0.50)	(1.75)	71	(0.12)	(1.80)	93
Cash finance costs	(1.27)	(2.24)	43	(1.27)	(1.79)	29
Corporate netback	2.23	3.33	(33)	4.78	(1.68)	385
Unrealized gain (loss) – commodity contracts	(2.37)	0.54	(539)	(1.51)	0.34	(544)
Stock based compensation	(1.16)	(3.03)	62	(1.22)	(3.04)	60
Depletion and depreciation	(11.02)	(14.14)	22	(10.72)	(11.42)	6
Impairment	(7.27)	(11.02)	34	(1.82)	(3.05)	40
Accretion	(0.50)	(0.60)	17	(0.46)	(0.55)	16
Gain on acquisitions and dispositions	-	29.43	(100)	-	8.55	(100)
Deferred income taxes	-	10.88	(100)	-	3.01	(100)
Net earnings (loss)	(20.09)	15.39	(231)	(10.95)	(7.84)	(40)

[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.

Clearview will continue to focus on optimizing its field operations while commencing drilling its light oil prospects and Wilson Creek and Windfall.

The Company's corporate netback for the year ended March 31, 2018 increased 385% to $4.78 per boe compared to the prior year corporate netback loss of $1.68 per boe. The increase is primarily due to improvement in realized gains from risk management contracts, general and administrative expenses, transaction costs and cash finance costs on a boe basis.

SUMMARY OF QUARTERLY RESULTS

	Q4 2018	Q3 2018	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017
Production								
Oil (bbl/d)	498	434	427	389	243	199	251	266
Natural gas liquids (bbl/d)	450	514	497	435	130	78	111	95
Natural gas (mcf/d)	7,175	7,085	7,576	7,006	2,223	1,591	1,866	2,004
Total (boe/d)	2,144	2,129	2,187	1,992	744	542	673	695
Financial								
Oil and natural gas sales	6,171	5,094	4,225	4,796	2,279	1,602	1,689	1,542
Adjusted funds flow (1)	429	1,189	824	1,237	223	(608)	(193)	170
Per share – basic	0.05	0.14	0.10	0.15	0.05	(0.14)	(0.05)	0.05
Per share – diluted	0.05	0.14	0.10	0.15	0.05	(0.14)	(0.05)	0.05
Net earnings (loss)	(3,879)	(2,435)	(1,864)	(282)	1,031	(1,028)	(780)	(1,119)
Per share – basic	(0.46)	(0.29)	(0.22)	(0.03)	0.21	(0.24)	(0.21)	(0.36)
Per share - diluted	(0.46)	(0.29)	(0.22)	(0.03)	0.21	(0.24)	(0.21)	(0.36)

(1) See non-GAAP measures.

Production was relatively flat on a quarter over quarter basis in the current fiscal year after a step change in production levels related to the property acquisitions in the fourth quarter of the prior year. Oil and natural gas sales increases on a quarterly basis as commodity prices, primarily oil and natural gas liquids continued to increase over the quarters. Adjusted funds flow improved with the increase in prices and stable production over most quarters. Adjusted funds flow for the fourth quarter of the current fiscal year was significantly lower than prior quarters due to realized losses on commodity contracts, transaction costs associated with the acquisition in the quarter and the subsequent to year end purchase of Bashaw Oil Corp. ("Bashaw"), a private oil and gas producer, and employee termination costs associated with the acquisition of Bashaw. The increased loss in the fourth quarter of the current year was primarily due to an impairment loss of $1,404 related to an asset held for sale, losses on risk management contracts and higher general and administrative expenses.

LIQUIDITY AND CAPITAL RESOURCES

The Company's liquidity was strengthened by the net equity financing of $25,825 and the $2,010 proceeds from the sale of non-core assets in fiscal 2017. Net debt is $14,154 at March 31, 2018 down from $14,604 at March 31, 2017, with the components set out below:

As at March 31	2018	2017
Trade and other receivables	2,711	2,310
Prepaid expenses and deposits	324	228
Assets held for sale	4,636	-
Bank debt	(16,250)	(14,250)
Accounts payable and accrued liabilities	(4,308)	(2,892)
Liabilities associated with assets held for sale	(1,267)	-
Net debt	(14,154)	(14,604)

Balance sheet strength and flexibility remain a priority through a challenging environment. The Company continues to proactively consider alternatives, including a further equity raise and/or non-core asset sales, building on the steps taken in fiscal 2017. Improved liquidity is a priority as the Company initiates its drilling plans and prepares for the next review of its credit facility, to be completed by August 31, 2018. The Company monitors net debt as a key component of managing liquidity risk and determining capital resources available to finance future development.

At March 31, 2018, the Company had a demand revolving operating facility with ATB Financial with a limit of $21,000 (March 31, 2017 - $26,000) of which $16,250 (March 31, 2017 - $14,250) was drawn. The reduction in the facility limit from $26,000 to $21,000 was a function of lower commodity prices. The interest rate is prime plus 3% and the loan agreement requires monthly interest payments only. The facility is subject to semiannual reviews with one completed in January 2018 resulting in a renewal with the same facility limit of $21,000. As the available lending limits are based on the lender's interpretation of the Company's reserves and future commodity prices, there can be no assurance as to the amount of available credit that will be determined at each scheduled review. The Company's credit facility is also a demand loan and as such the lender could demand repayment at any time. Because the facility is a demand loan it is classified as a current liability. Management is not aware of any indications the lender would demand repayment. The Company is current with all interest and fee payments and is compliant with all financial and non-financial covenants, particularly the working capital covenant. Refer to Note 7 of the Company's audited financial statements for the definition of how this covenant is calculated. The Company's ratio as per the working capital covenant is 2.2 to 1, well in excess of the minimum requirement of 1:1.

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 managing its commodity price risk management program.

CONTRACTUAL OBLIGATIONS

The Company is committed to future minimum payments for natural gas transmission and office space. In 2018, the Company entered a lease for new office space which expires June 29, 2020. The Company recovers a portion of the office costs from co-occupants.

The following is a summary of the Company's future minimum contractual obligations and commitments as of March 31, 2018:

	2019	2020	2021	2022	Thereafter
Bank debt	-	16,250	-	-	-
Accounts payable and accrued liabilities	-	4,308	-	-	-
Decommissioning obligations	-	-	-	-	18,873
Financial instruments	1,131	-	-	-	-
Gas transportation	173	36	6	6	2
Office lease	165	178	44	-	-
Total	1,469	20,772	50	6	18,875

OFF-BALANCE SHEET ARRANGEMENTS

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

OUTSTANDING SHARE DATA

The Company is authorized to issue an unlimited number of voting common shares, an unlimited number of non-voting common shares and an unlimited number of preferred shares, issuable in series. As of June 27, 2018, the Company has 8,437,866 voting common shares outstanding and options to acquire 722,333 voting common shares outstanding. All outstanding options have a 7-year life from the date of grant and vest as follows, based on respective exercise prices of $4.50 and $5.00.

Vesting period	Options - $4.50	Options - $5.00	Total
Currently vested	236,833	-	236,833
Vesting in the future in the three months ending:			
June 30, 2018	101,600	107,000	208,600
September 30, 2018	1,733	-	1,733
December 31, 2018	26,833	2,500	29,333
June 30, 2019	-	107,000	107,000
December 31, 2019	26,834	2,500	29,334
June 30, 2020	-	107,000	107,000
December 31, 2020	-	2,500	2,500
Total	393,833	328,500	722,333

For further details about the options refer to Note 9 to the Financial Statements as at and for the year ended March 31, 2018.

RELATED PARTY TRANSACTIONS

Related party transactions are disclosed in Note 12 of the financial statements as at and for the year ended March 31, 2018.

The Company has an agreement with the former President and Chief Executive Officer of the Company which assigns a 1% gross over-riding royalty interest on all production or royalty revenue from those oil or natural gas properties owned by the Company as at June 28, 2016. This royalty interest is attached to the property and would transfer to the purchaser on the sale or other disposition of the property. The production subject to this royalty interest is approximately 25% of the total production for fiscal year 2018 resulting in gross over-riding royalties (“GORR”) paid or payable to the former President and Chief Executive Officer, of $85 in the year ended March 31, 2018 compared to $65 in the prior year.

During the year ended March 31, 2018 $39 (2017 - $31) was recovered for shared office occupancy costs from Front Range Resources Ltd., a company with a director in common. Geological systems cost of $19 (year ended March 31, 2017 - $19) were paid to this same related party in the year ended March 31, 2018.

PROPOSED TRANSACTIONS

On April 16, 2018, subsequent to the fiscal year, the Company acquired Bashaw Oil Corp., a private oil and gas producer (“Bashaw”) through the issuance of 1,560,046 voting common shares to the shareholders of Bashaw. Bashaw was the operator and other 50% working interest partner of the Windfall asset acquired in the fourth quarter of the year. The acquisition will have a positive effect on the Company’s financial position due to the cash position and positive working capital of Bashaw at the time of closing and it will double the operating netback from the property by increasing the Company’s working interest in the property to 100%. There are no further shareholder or regulatory approvals required

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 years ended March 31, 2018 and 2017. Certain estimates and judgments are described in Note 2 to the audited financial statements for the years ended March 31, 2018 and 2017. 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 2.0% inflation factor to its estimate of current costs. The Company believes this inflation factor is reasonable over the long term and is consistent with rates used by others in the industry. The risk-free rate is used to discount decommissioning provisions to the current reporting date. Expected retirement dates are based on the productive life of the wells as determined by the independent qualified reserves evaluator and by regulatory requirements. In estimating the fair value of decommissioning obligations which are a component of a business combination, the Company uses a market discount rate, which is usually a 10% discount rate.

Stock based compensation

The Company's accounting policy for stock based compensation was applied to account for the options granted during the years ended March 31, 2018 and 2017. The latter was the first year in which the Company granted options to acquire voting common shares. 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 recently issued voting common shares. 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 a sample of peer junior 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 market place.

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.

In Q1 2018 management reviewed its cash generating units following the acquisitions in Q4 2017 and in light of its current strategic and operating objectives. The review resulted in the combining of the two Southern Alberta CGUs as both prior CGUs are oil producing assets, the assets are geographically proximate to one another and both are outside the Company's core operating area of Greater Pembina, Alberta. Both CGUs were adjusted for impairment at March 31, 2017 and therefore carried at their respective recoverable amounts at March 31, 2017. Once combined, as of April 1, 2017, the carrying value of the combined CGU is $7,446, being the sum of the recoverable amounts at March 31, 2017.

NEW ACCOUNTING POLICIES

No new or amended accounting standards or interpretations were adopted during the year ended March 31, 2018.

New accounting standards not yet adopted

IFRS 15, "Revenue from Contracts with Customers" is effective for annual periods beginning on or after January 1, 2018 and will be adopted by the Company for its fiscal year beginning April 1, 2018. IFRS 15 establishes a single revenue recognition and measurement framework that applies to contracts with customers. The standard requires an entity to recognize revenue to reflect the transfer of good and services for the amount it expects to receive, when control is transferred to the purchaser. Disclosure requirements have also been expanded including requiring greater disaggregation of revenue streams. The Company is in the process of reviewing its revenue streams and underlying contracts with customers and does not expect that the adoption of IFRS 15 will have a material impact on earnings. The adoption of IFRS 15 will result in expanded disclosures in the Company's financial statements.

IFRS 9, "Financial Instruments" is effective for annual periods beginning on or after January 1, 2018 and will be adopted by the Company for its fiscal year beginning April 1, 2018. IFRS 9 replaces IAS 39, "Financial Instruments: Recognition and Measurement" and uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. For financial liabilities designated at fair value through profit or loss, a company can recognize the portion of the change in fair value related to the change in the company's own credit risk through other comprehensive income rather than profit or loss. The new standard also requires a single impairment method to be used, replacing the multiple impairment methods in IAS 39, and incorporates new hedge accounting requirements which align hedge accounting more closely with risk management. The Company currently does not intend to apply hedge accounting to any of its existing financial instrument contracts upon adoption of IFRS 9. Adoption of IFRS 9 is not expected to have a material impact on the measurement and carrying values of the Company's financial instruments.

IFRS 16, "Leases" will come into effect for fiscal years beginning on or after January 1, 2019, with earlier adoption permitted but only if the Company also applies IFRS 15, "Revenue from Contracts with

Customers". The Company currently does not intend to early adopt and accordingly the new standard will be effective for the fiscal year beginning in 2019. IFRS 16 sets out principles for the recognition, measurement, presentation and disclosure of leases and will require lessees to recognize most lease assets and lease obligations on the balance sheet, effectively classifying all leases as finance leases. Certain short-term leases (less than 12 months) and leases of low-value assets are exempt from the requirements. The Company does not expect to adopt the standard early and management is currently assessing the potential impact of the adoption of IFRS 16 on the Company's financial statements.

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 March 31, 2018 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.

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.

Adjusted funds flow is a non-GAAP measure derived from cash flow from operating activities excluding decommissioning expenditures and changes in non-cash working capital. The adjusted funds flow amount represents funds available for capital expenditures, repayment of net debt or distribution to shareholders. See the reconciliation of adjusted funds flow to cash flow from operations set out under the heading "Adjusted Funds Flow" in this MD&A.

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

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

Natural gas is converted to a barrel of oil equivalent ("boe") using six through cubic feet of gas to one barrel of oil. Boe's may be misleading, particularly if used in isolation. A conversation ratio of one barrel to six thousand cubic feet of natural gas is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead. **Given that the value ration based on the current price of cured oil as compared to natural gas is significantly difference from the energy equivalency of 6:1, using a conversion ratio on a 6:1 basis may be misleading as an indication of value.**

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. Specifically, this document includes forward looking information with respect to: future drilling plans, completion plans, waterflood recovery, operating cost efficiencies, divestiture and acquisition plans, continued compliance with covenants under the credit facility, debt levels and overall growth strategy. 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

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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