CLEARVIEW
RESOURCES LTD

Clearview Resources Ltd.

Management Discussion and Analysis (MD&A)

December 31, 2017

HIGHLIGHTS FOR THE NINE MONTHS ENDED DECEMBER 31, 2017

- *Optimization and production*
  - *optimization of production from existing well and facilities on the properties acquired in Q4 2017 was a focus in YTD 2018,*
  - *the optimization projects have been successful:*
    - *served as the primary driver for the increases in Q2 2018 (2,187 boe/d) and Q3 2018 (2,129 boe/d) production compared to 1,992 boe/d for Q1 2018, and*
    - *provided incremental production at a cost of approximately $6,000 per flowing boe and for which payback is less than 1 year (refer to page 13).*
- *Operating results*
  - *Q3 2018 cash inflow from operations is $1,189 compared to cash outflow to operations of ($608) for Q3 2017 which on a per boe basis are $6.07 and $(12.04), respectively,*
  - *natural gas prices were low in both Q2 2018(realized - $1.26/mcf) and Q3 2018 (realized - $1.40/mcf) and the primary reason for the low operating netbacks in each of these quarters,*
  - *the hedging strategy partially offset this lower cash flow generating $280 or $1.43/boe in Q3 2018 and $476 or $2.37/boe in Q2 2018,*
  - *YTD 2018 production costs (net of processing fee revenue) are $14.17/boe compared to $18.39/boe for YTD 2017, and*
  - *YTD 2018 general and administrative costs are $2.27/boe compared to $4.52/boe for YTD 2017 while Q3 2018 and Q3 2017 costs are $2.18/boe and $5.04/boe, respectively.*
- *Acquisition and development*
  - *in January 2018 the Company acquired a 50% working interest in an Alberta light oil property (Windfall) in the Greater Pembina core area; 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 the light oil (Bluesky) with up to 16 gross (8 net) locations planned of which 3 gross (1.5 net) are planned for 2018.*
  - *actively participated in crown land sales in YTD 2018, acquiring 10.5 gross sections (10.5 net) contiguous to existing lands in the Greater Pembina core area, at an average cost of $39.42 per acre,*
  - *continued actively analyzing and planning to drill in the Greater Pembina Core Area, and*
  - *attained three licenses to drill horizontal wells targeting Cardium oil.*
- *Liquidity*
  - *balance sheet strength and flexibility remain a priority through a challenging environment; the Company continues to proactively consider alternatives building on the equity raises and non-core property dispositions undertaken in fiscal 2017.*
- *Licensing liability rating*
  - *maintained the Company's rating at approximately 3, well in excess of the corporate minimum of 2 as set by the Board of Directors.*

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OVERVIEW OF THE COMPANY

Clearview Resources Ltd. (the "Company") is a growth-oriented oil and natural gas producing company based in Calgary, Alberta with production and development focused in the Greater Pembina area of Alberta. 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 a 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	6,266	86.7%	Yes
	Pembina[2]	Liquids rich natural gas	1,923	92.7%	Yes
	Wilson Creek[2]	Light oil and liquids rich natural gas	4,033	61.3%	Yes
	Lindale (Unit)	Light oil with associated natural gas and liquids	515	10.6%	No
Other	Bantry	Medium oil	573	40.0%	No
	Caribou[2]	Light oil	436	69.3%	Yes
	Carstairs (Unit)	Liquids rich natural gas	401	17.0%	No
	Carmangay	Light oil	273	20.1%	No
	Crossfield (Unit)	Liquids rich natural gas	145	4.2%	No
	Warburg (Unit)	Light oil	40	3.8%	No
	Caroline (Unit)	Liquids rich natural gas	12	0.2%	No
	East Crossfield (Unit)	Liquids rich natural gas	-	4.9%	No
	Miscellaneous	Various	13	Various	Mixed
Total			14,630		

[1]mboe of total proved plus probable reserves at March 31, 2017 as determined by the independent reserves evaluator, GLJ Petroleum Consultants

[2] acquired in Q4 2017 except for approximately 17% of the Wilson Creek reserves

[3]operatorship of the majority of the property

GENERAL

This management discussion and analysis ("MD&A") of the Company for the three and nine months ended December 31, 2017 contains financial highlights but does not contain the complete financial statements of the Company. It should be read in conjunction with the Company's unaudited, Condensed Interim Financial Statements for the three and nine months ended December 31, 2017 and the Audited Financial Statements for the year ended March 31, 2017 and the MD&A dated March 31, 2017. Refer to page 20 for information about non-IFRS measures and page 21 for information on forward-looking statements used in the MD&A. All references to dollar amounts are in thousands of Canadian dollars ($000`s) except per unit amounts and if otherwise indicated. This MD&A includes events up to February 21, 2018. Additional information is available on SEDAR at www.sedar.com.

STRATEGY OF THE COMPANY

In fiscal 2017 the Company achieved the following in transforming to a growth strategy:

- established Greater Pembina as the core focus area by acquisitions (approximately $30,000) in Q4 2017, creating the following corporate strengths:
    - operatorship of most of the land and wells,
    - significant low risk development (both oil and natural gas) opportunities in multiple geological zones of some 70 gross (52 net) drilling locations of which 40 gross (30 net) were recognized by the independent reserve evaluators at March 31, 2017,
    - License Liability Rating ("LLR") of approximately 3, and
    - strong lending values.
- closed three tranches of equity financing by issuing voting common shares:
    - August 2016 - $5,000 - 1,111,111 shares at $4.50 per share,
    - February 2017 - $5,200 – 1,040,051 shares at $5.00 per share, and
    - March 2017 - $15,625 – 3,187,922 shares at $5.00 per share.
- sold two non-core properties in October 2016 for cash proceeds totaling $2,010.
- achieved the following metrics by April 1, 2017:
    - production – approximately 2,000 boe/d,
    - total proved producing reserves - 5.1 mboe,
    - total proved reserves - 9.2 mmboe,
    - total proved plus probable reserves -14.6 mmboe, and
    - LLR – approximately 3.
- established the following metrics as the basis for growth and to drive the management incentive plan:

Category	Metric	Threshold or Target
Valuation	Net asset value[1] per fully diluted share	15% growth
Operations	Recycle ratio[2]	1.6 or greater
Financial	Net debt to cash flow ratio	No greater than 2.0
	License liability rating ("LLR")	Greater than 2.0

[1] Future cash flows from proved plus probable reserves present valued at a discount rate of 10%.

[2] Operating netbacks for the period divided by finding, development and acquisition costs for the period.

Integrating the acquired and legacy assets and the management team has been the focus of YTD 2018, along with planning for development in the Greater Pembina core area.

OPERATIONS AND DEVELOPMENT

Production is summarized in the following table:

Periods ended December 31	3 months Q3 2018	3 months Q3 2017	9 months YTD 2018	9 months YTD 2017
Oil and liquids – bbl/d	948	287	899	337
Natural gas – mcf/d	7,085	1,570	7,223	1,813
Total – boe/d	2,129	548	2,103	639

YTD 2018 production increased over prior periods due to the production from the Q4 2017 acquisitions and newly drilled wells at Lindale. Production (boe/d) from these properties follows:

Property	3 months Q3 2018	9 months YTD 2018
Wilson Creek	423	444
Northville, Pembina and Caribou	1,298	1,242
Lindale	105	107
Total from the above properties	1,826	1,793
% of total production from above properties	86%	85%

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 $924 of which $311 was incurred in YTD 2018.

The Company participated in crown land sales in YTD 2018, investing $253 to acquire 10.5 gross (10.5 net) acres at an average price of $39.42/acre. The acquired land and mineral rights are immediately adjacent to existing lands in the Greater Pembina core area.

Total capital expenditures for YTD 2018 were $2,456 comprised of the following:

Nature	Property	Objective	Cost
Land	Greater Pembina Core Area	Acquire mineral rights	253
Geological	Greater Pembina Core Area	Develop low risk growth opportunities	152
DCET[1]	Lindale Cardium Unit	Complete the 3 well drilling programs	311
Optimization	Caribou	Enhance production from low producing wells	646
Optimization	Northville, Pembina	Enhance production from low producing wells	302
Optimization	Wilson Creek	Enhance production from low producing wells	60
Water flood	Lindale Cardium Unit	Initial steps for enhanced secondary recovery	211
Facilities/waterflood	Carmangay	Gathering system and related facilities	212
Facilities	Northville, Pembina	Compressor overhauls and turnarounds	261
Other	Various	Capital maintenance	48
Total			2,456

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

The Company continues its planning, analysis and preparation for the drilling of horizontal wells, resulting in three drilling licenses for its Wilson Creek property targeting the Cardium formation (light oil). The timing of the development depends on a number of factors, including availability of drilling rigs, weather and oil and natural gas price forecasts.

The Company also participates in development opportunities proposed by operating partners, subject to satisfactory technical and economic analysis, for example, the recent drilling of Cardium oil wells on the non-operated property at Lindale.

The Company's operating results are analyzed in Tables C and D on pages 9 and 10. YTD 2018 generated operating netback (petroleum revenue plus processing fees less royalties, transportation and production expense) of $4,425 compared to $1,123 in YTD 2017. Q1 2018 is the first quarter to include the increased operating cash flows as a result of the properties acquired in Q4 2017. Corporate netback (operating netback less general, administrative and financing expense, plus or minus the gain or loss on hedge contracts) for YTD 2018 amounted to $3,250 compared to an outflow of ($566) in YTD 2017. The outflow in YTD 2017 includes transaction costs of $319 related to work on acquisitions and related financings, both of which closed the subsequent quarter. YTD 2018 includes the increased scale of operations due to the acquisitions. Operating netback increased in Q3 2018 to $1,557 compared to $978 in Q2 2018 primarily due to higher oil and liquids prices as Q3 2018 averaged $47.98/bbl compared to $39.32/bbl in Q2 2018.

OUTLOOK

As of February 21, 2018, the Company is producing approximately 2,200 boe/d with the weighting being approximately 44% for oil + liquids and 56% for natural gas. This outlook includes the 110 boe/d of production from the property acquired in early January 2018.

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 $13,910 at December 31, 2017 down from $14,604 at March 31, 2017, with the components set out in Table A on Page 8. 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 in 2018 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 December 31, 2017, the Company had a demand revolving operating facility with ATB Financial with a facility limit of $21,000 (March 31, 2017 - $26,000) of which $14,300 (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% (Q3 2018 - 6.20%) 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 a facility limit of $21,000. The Company anticipates a decrease in the facility with the next review reflecting the prolonged period of low natural gas prices. 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 as the Company's draw on the loan is currently well below the facility cap, the Company is current with all interest and fee payments and is in compliance with all covenants, particularly the working capital covenant. The Company's ratio as per the working capital covenant is 3.1 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. The following table lists commodity contracts held by the Company:

Commencement Date	Expiry Date	Units	Volume	Underlying Commodity	Fixed Price
Currently outstanding and outstanding throughout YTD 2018					
March 1, 2017	February 28, 2018	bbls/d	50	NYMEX WTI CDN	$70.52
April 1, 2017	March 31, 2018	bbls/d	50	NYMEX WTI CDN	$70.00
April 1, 2017	March 31, 2018	bbls/d	50	NYMEX WTI CDN	$70.25
March 1, 2017	February 28, 2018	GJ/d	700	CGPR AECO CDN	$2.70
April 1, 2017	March 31, 2018	GJ/d	1,200	CGPR AECO CDN	$2.77
Currently expired but outstanding for most of YTD 2018					
February 1, 2017	January 31, 2018	bbls/d	50	NYMEX WTI CDN	$70.00
May 1, 2017	October 31, 2017	GJ/d	950	CGPR AECO CDN	$2.735
June 1, 2017	December 31, 2017	GJ/d	950	CGPR AECO CDN	$2.90
Currently outstanding and contracted in Q3 2018					
January 1, 2018	December 31, 2018	bbls/d	100	NYMEX WTI CDN	$65.00
January 1, 2018	December 31, 2018	bbls/d	100	NYMEX WTI CDN	$67.25
January 1, 2018	December 31, 2018	bbls/d	100	NYMEX WTI CDN	$70.00

Management monitors the market and additional hedges will be contracted as attractive pricing opportunities become available and if production increases from development or acquisitions.

Currently the Company has 8,437,866 voting common shares 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
Q3 2018 and prior	235,833	-	235,833
Three months ending:			
June 30, 2018	101,600	109,500	211,100
September 30, 2018	1,733	-	1,733
December 31, 2018	27,333	-	27,333
June 30, 2019		109,501	109,501
December 31, 2019	27,333	-	27,333
June 30, 2020	-	109,500	109,500
Total	393,832	328,501	722,333

For further details about the options refer to Note 7 to the Financial Statements as at and for the three and nine months ended December 31, 2017.

TABLE A – EXTRACTS FROM THE FINANCIAL STATEMENTS ($000's)

From the Statements of Financial Position	December 31, 2017	March 31, 2017	December 31, 2016
Trade and other receivables	3,040	2,310	552
Deposits and prepaid expenses	781	228	127
Credit facility	(14,300)	(14,250)	(3,775)
Accounts payable and accrued liabilities	(3,431)	(2,892)	(1,877)
Net debt	(13,910)	(14,604)	(4,973)
Current assets	3,821	2,574	679
Property, plant and equipment	65,441	68,582	26,902
Total assets	69,262	71,156	27,581
Current liabilities	18,404	17,142	5,652
Asset retirement obligation	16,318	15,607	5,517
Total shareholders' equity	34,540	38,407	16,412
Total liabilities and shareholders' equity	69,262	71,156	27,581

From the Statements of Cash Flows	YTD 2018	YTD 2017
Provided by (used in) operating activities	1,795	(3)
Provided by the issue common shares	-	5,000
Used to acquire property, plant & equipment	(2,456)	(101)

TABLE B – INCOME (EXPENSES) NOT SETTLED IN CASH

	Q3 2018	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017	Q4 2016
Stock based compensation	(228)	(246)	(240)	(203)	(155)	(81)	(296)	-
Depletion and depreciation	(2,107)	(2,135)	(1,904)	(947)	(513)	(645)	(659)	(606)
Impairment	-	-	-	(738)	-	-	-	5,200
Accretion–asset retirement obligation	(95)	(83)	(84)	(40)	(27)	(33)	(34)	(36)
Gains -acquisitions or dispositions[1]	-	-	-	2,700	99	-	-	-
Unrealized gain (loss) - hedges	(1,194)	(224)	709	36	175	172	(300)	(47)
Total	(3,624)	(2,688)	(1,519)	808	(421)	(587)	(1,289)	4,511

[1] Inclusive or net of related deferred income taxes if applicable

TABLE C – OPERATING RESULTS YTD 2018 & 2017
($000's, except for production and per unit amounts)

Operating results for the nine months ended December 31	YTD 2018	YTD 2017
Production – oil and liquids – bbls	247,315	92,593
Production – natural gas - mcf	1,986,320	498,487
Production – total - boe	578,369	175,674
Production – oil and liquids – bbls per day	899	337
Production – natural gas – mcf per day	7,223	1,813
Production – total – boe/d	**2,103**	**639**
Oil and natural gas liquids revenue	10,640	3,869
Natural gas revenue	3,474	1,031
Total production revenue	14,114	4,900
Processing fee revenue	569	492
Total production and processing fee revenue	14,683	5,392
Royalties	(1,498)	(547)
Production and transportation	(8,760)	(3,722)
Operating netback	**4,425**	**1,123**
Realized hedge gain (loss)	875	(293)
General and administrative	(1,315)	(794)
Transaction	-	(319)
Interest and other financing costs (1)	(735)	(283)
Corporate netback	**3,250**	**(566)**
(Expenses) income not settled in cash – see Table B	(7,831)	(2,297)
Net income (loss)	(4,581)	(2,863)
Net income (loss) per share - basic	(0.54)	(0.77)
Net income (loss) per share – fully diluted	(0.54)	(0.77)
Royalties as % of total revenue	**11%**	**11.2%**

Per unit analysis - $ per unit		
Oil and liquids revenue – $/bbl	43.02	41.79
Natural gas revenue – $/mcf	1.75	2.07
Total petroleum revenue - $/boe	24.40	27.89
Processing fee revenue - $/boe	0.98	2.80
Royalties – $/boe	(2.59)	(3.12)
Production and transportation – $/boe	(15.15)	(21.19)
Operating netback – $/boe	**7.65**	**6.39**
Realized hedge gain (loss) - $/boe	1.51	(1.67)
General and administrative –$/boe	(2.27)	(4.52)
Transaction - $/boe	-	(1.82)
Interest and other financing costs (1) –$/boe	(1.27)	(1.61)
Corporate netback – $/boe	**5.62**	**(3.23)**

(1) Expenses settled in cash

TABLE D – OPERATING RESULTS FOR THE LAST EIGHT QUARTERS

($000's, except for production and per unit amounts)

Operating results for three months	Q3 2018	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017	Q4 2016
Production – oil and liquids – bbls	87,196	85,065	75,055	33,636	26,374	33,339	32,880	34,823
Production – natural gas – mcf	651,826	696,951	637,543	200,058	144,448	171,672	182,367	175,931
Production - total boe	195,833	201,223	181,312	66,979	50,449	61,950	63,274	64,145
Production–oils & liquids- bbls/d	948	925	825	374	287	362	361	383
Production –natural gas - mcf/d	7,085	7,576	7,006	2,223	1,570	1,866	2,004	1,933
Production – boe/d	**2,129**	**2,187**	**1,992**	**744**	**548**	**673**	**695**	**705**
Oil and natural gas liquids revenue	4,184	3,345	3,112	1,674	1,225	1,340	1,303	1,091
Natural gas revenue	910	880	1,684	539	421	371	239	247
Total production revenue	5,094	4,225	4,796	2,213	1,646	1,711	1,542	1,338
Processing fee revenue	203	198	167	187	176	158	159	158
Total production and fee revenue	5,297	4,423	4,963	2,400	1,822	1,868	1,701	1,496
Royalties	(569)	(412)	(517)	(271)	(252)	(270)	(25)	(160)
Production and transportation	(3,171)	(3,033)	(2,556)	(1,244)	(1,363)	(1,225)	(1,134)	(1,163)
Operating netback	**1,557**	**978**	**1,890**	**885**	**207**	**374**	**542**	**173**
Realized hedge gain (loss)	280	476	119	19	(164)	(77)	(52)	11
General and administrative	(427)	(352)	(535)	(479)	(254)	(312)	(227)	(229)
Transaction	-	-	-	(117)	(319)	-	-	-
Interest and other financing costs [1]	(221)	(278)	(237)	(150)	(78)	(112)	(93)	(93)
Corporate netback	**1,189**	**824**	**1,237**	**158**	**(608)**	**(127)**	**170**	**(138)**
(Expenses) income not settled in cash[2]	(3,624)	(2,688)	(1,519)	808	(421)	(587)	(1,289)	4,511
Net income (loss)	(2,435)	(1,864)	(282)	966	(1,029)	(714)	(1,119)	4,373
Net income (loss)/share - basic	(0.29)	(0.22)	(0.03)	0.21	(0.24)	(0.19)	(0.36)	1.41
Net income (loss)/share – fully diluted	(0.29)	(0.22)	(0.03)	0.19	(0.24)	(0.19)	(0.34)	1.41
Royalties as % of revenue	**11%**	**10%**	**11%**	**12%**	**15%**	**16%**	**2%**	**12%**
Per unit analysis - $ per unit								
Oil and liquids revenue- $/bbl	47.98	39.32	41.45	49.74	46.44	40.22	39.66	31.33
Natural gas revenue – $/mcf	1.40	1.26	2.64	2.70	2.92	2.16	1.31	1.40
Production revenue – $/boe	26.01	21.00	26.45	33.03	32.63	27.62	24.38	20.87
Processing fee revenue - $/boe	1.03	0.99	0.92	2.80	3.50	2.56	2.51	2.46
Royalties –$/boe	(2.90)	(2.05)	(2.85)	(4.05)	(5.00)	(4.35)	(0.40)	(2.50)
Production & transportation–$/boe	(16.19)	(15.07)	(14.10)	(18.57)	(27.02)	(19.77)	(17.92)	(18.13)
Operating netback – $/boe	**7.95**	**4.86**	**10.42**	**13.21**	**4.11**	**6.04**	**8.57**	**2.70**
Realized hedge gain (loss) - $/boe	1.43	2.37	0.66	0.29	(3.25)	(1.25)	(0.82)	0.17
General and administrative - $/boe	(2.18)	(1.75)	(2.95)	(7.15)	(5.03)	(5.04)	(3.59)	(3.58)
Transaction - $/boe	-	-	-	(1.75)	(6.32)	-	-	-
Interest & financing costs (1)-$/boe	(1.13)	(1.38)	(1.31)	(2.24)	(1.55)	(1.81)	(1.47)	(1.45)
Corporate netback – $/boe	**6.07**	**6.82**	**6.82**	**2.36**	**(12.04)**	**(2.06)**	**2.69**	**(2.16)**

[1] Expenses settled in cash [2] Details in Table B

TABLE E – BENCHMARK PRICES FOR OIL AND NATURAL GAS

	Q3 2018	Q2 2018	Q1 2018	Q4 2017	Q3 2017	Q2 2017	Q1 2017	Q4 2016
Natural gas–AECO 30-day spot $/mcf	1.72	1.61	2.79	2.69	3.11	2.36	1.42	1.83
Pentane/condensate	73.71	61.42	64.40	69.28	64.88	56.82	55.81	45.34
Butane	53.19	39.90	38.68	44.53	42.35	33.20	32.39	29.34
Propane	40.29	26.66	19.21	28.81	25.08	12.23	9.96	7.14
Oil – Edmonton light 40 API - $/bbl	65.68	57.15	59.72	64.83	60.76	54.21	55.01	41.22
Oil – Hardisty Bow River 24.9 API - $/bbl	52.79	48.25	50.30	49.72	46.99	41.33	41.93	26.63
Differential – medium oil - $/bbl	12.88	8.91	9.42	15.17	16.12	12.86	13.08	14.59

EXPLANATION OF THE RESULTS OF OPERATIONS

Production and Revenue (refer to Tables C and D on pages 9 & 10)

Production[1] and realized prices by commodity are summarized in the following table:

Periods ended December 31	3 months Q3 2018	3 months Q3 2017	9 months YTD 2018	9 months YTD 2017
Oil and liquids – bbl/d	948	287	899	337
Natural gas – mcf/d	7,085	1,570	7,223	1,813
Total – boe/d	2,129	548	2,103	639
Oil production[2] – bbls	39,851	18,537	114,393	65,734
Liquids production[2] – bbls	46,989	7,837	131,945	26,859
Natural gas production[2] – mcf	646,654	144,448	1,972,030	498,487
Realized oil price[2] - $/bbl	62.79	51.38	58.55	47.12
Realized liquids price[2] – $/bbl	35.14	35.70	31.28	29.36
Realized natural gas price[2] - $/mcf	1.39	2.84	1.82	2.04

[1]Q3 2018 and YTD 2018 include production from the properties acquired in Q4 2017 but the Q3 2017 and YTD 2017 do not.
[2]Productiion volumes and related revenue excludes production from royalty interests and the revenue is net of pipeline tariffs.

Average production for Q3 2018 (2,129 boe/d) is greater than Q3 2017 (548 boe/d) due to the production from the Q4 2017 acquisitions which contributed approximately 75% of the YTD 2018 production. Lindale produced 105 boe/d in Q3 2018, which is approximately the same as the production in Q3 2017. Production from the three (0.32 net) oil wells drilled in March 2018 (two commenced production in April 2017 and the third in August 2017) offset the normal declines that would otherwise have occurred.

Benchmark prices

Benchmark prices are provided in Tables E above. The refiners' posted prices are influenced by the US$ WTI reference price, transportation capacity and costs, US$/C$ exchange rates and the supply/demand situation of particular crude oil quality streams during the period. Both oil and natural gas benchmark prices have been low throughout the eight quarters shown in Table E above compared to prior years. Benchmark oil and liquids have performed reasonably well in Q3 2018 with butane and propane showing significant gains. On the other hand, natural gas prices continue to be low. The Q3 2018 differential between light and medium gravity oil was $12.88/bbl compared to the Q3 2017 differential of $16.12/bbl as shown in Table E. Benchmark natural gas prices in Q1 2018 averaged $2.79/mcf but declined significantly to $1.61in Q2 2018 and $1.72 in Q3 2018.
Realized natural gas prices followed this same pattern.

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 for Q3 2018 is $53.19/bbl compared to $42.35/bbl in Q3 2017 and $39.90/bbl in Q2 2018. Similarly, propane was $40.29/bbl in Q3 2018 compared to $25.08/bbl in Q3 2017 and $26.66/bbl in Q2 2018.

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 as shown in Table E on page 11. The Company's realized price for natural gas in Q3 2018 of $1.40/mcf and Q2 2018 of $1.26/mcf, are lower than the respective benchmark prices of $1.72/mcf and $1.61/mcf due to pipeline constraints affecting the Greater Pembina core area in those periods.

Gains and losses on commodity contracts

The table on page 7 lists the financial commodity price contracts outstanding during YTD 2018 generating a realized gain of $875 (YTD 2017 – realized loss- $293) and unrealized losses of $709 (YTD 2017 – unrealized gain - $47). The unrealized loss reflects the fact that oil prices at December 31, 2017 exceeded the contracted prices for the remaining volumes in the hedge agreements.

Royalties (refer to Tables C and D on pages 9 & 10)

Royalty costs Periods ended December 31	3 months Q3 2018	3 months Q3 2017	9 months YTD 2018	9 months YTD 2017
Crown royalties - oil	138	15	342	72
Crown royalties – natural gas and liquids	606	82	1,590	235
Crown royalties - gas cost allowance	(519)	(65)	(1,283)	(355)
Freehold royalties – all commodities	179	176	437	463
Gross overriding royalties[1] – all commodities	165	44	412	132
Total	569	252	1,498	547
Royalties as a % of petroleum revenue	11%	15%	11%	11%

[1]Includes royalty to related party – see page 16.

Freehold and gross overriding royalties are generally at a fixed rate whereas crown royalties are on a sliding scale, i.e. decreasing with lower volumes and prices. The overall royalty burden for YTD 2018 and YTD 2017 are the same at 11%, The variation for Q3 2018 (11%) and Q3 2017 (15%) is explained by the change in mix of the properties to be a much higher gas weighting in 2018 as the gas crown royalty is reduced by the gas cost allowance.

The Company reviews its entitlement to gas cost allowance at each reporting period end. 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.

Production and transportation costs (refer to Tables C & D on pages 9 & 10)
Processing fee revenue

Production and transportation costs Periods ended December 31	3 months Q3 2018	3 months Q3 2017	9 months YTD 2018	9 months YTD 2017
Transportation, gathering and processing	1,012	174	2,976	578
Workover, repairs and maintenance	629	387	1,580	866
Property taxes, lease rentals and regulatory fees	382	160	1,086	634
Lifting costs	1,148	642	3,118	1,644
Total production and transportation costs	3,171	1,363	8,760	3,722
Processing fee revenue	(203)	(176)	(569)	(492)
Production & transportation expense less processing fees	2,968	1,187	8,191	3,230
Workover, repairs and maintenance – $/boe	3.21	7.67	2.73	4.93
All other costs above – $/boe	12.97	19.35	12.42	16.27
Total production & transportation costs –$/boe	16.18	27.02	15.15	21.19
Processing fee revenue – $/boe	(1.03)	(3.50)	(0.98)	(2.80)
Production activity –$/boe	15.15	23.52	14.16	18.39

Property, plant and equipment include working interests in natural gas processing facilities at Caroline, Carstairs, Crossfield and Wilson Creek. These facilities generate processing fee revenue for the Company which is analyzed in the above table along with the significant components of production and transportation costs.

The Company and its operating partners have focused on reducing production costs given the prolonged period of low oil and natural gas prices. However, significant 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 Q4 2017) 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 Q2 and Q3 2018 as the objective was to complete the projects in advance of winter weather conditions. These projects drove the higher production in Q2 and Q3 2018 (average 2,158 boe/d) compared to 1,992 boe/d in Q1 2018. The higher total production in Q2 and Q3 amounts to 22,152 bbls of oil and liquids and 73,690 mcf of natural gas which at average prices realized in Q2 and Q3 generated incremental revenue of $1,096. Much of the incremental revenue flows through as operating netback given the fixed nature of a significant portion of the production costs for an existing well. Thus, the payback from the workover projects is short. It is estimated that all workover costs will be recovered within one year with a significant portion recovered by December 31, 2017 due to the additional revenue of $1,096 noted above.

Q3 2018 production and transportation costs/boe ($15.15/boe) are lower than Q3 2017 ($23.52/boe). The lower costs per unit are a combination of the following: the shift in production mix to a greater natural gas weighting of 55% in Q3 2018 compared to 48% in Q3 2017, the economies of scale of higher production and a strong focus on cost control. Natural gas production costs per unit are 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 costs (refer to Tables C and D on pages 9 & 10)

General and administrative costs Periods ended December 31	3 months Q3 2018	3 months Q3 2017	9 months YTD 2018	9 months YTD 2017
Human resources	297	188	819	523
Professional fees	60	12	185	113
Office and other	70	54	311	158
Total general and administrative costs	427	254	1,315	794
General and administrative – $/boe	2.18	5.03	2.27	4.52

Professional fees include audit, legal and reserve evaluation services for which the estimated annual costs which are accrued evenly over the quarters.

YTD 2018 include the following unusual costs:

- the costs of moving to new office premises in Q1 2018 of $37,
- the transition from personnel on a consulting fee basis to be salaried employees was not completed until Q2 2018 resulting in higher human resource costs in Q1 2018,
- bad debt expense of $56 related to an industry partner which went into receivership, and
- systems acquisition and set up costs of $35.

Higher human resource costs were incurred in YTD 2018 compared to YTD 2017 as the Company employed 8 full time people which includes additional personnel (3 full time and 1 part-time) due to the growth through acquisitions in Q4 2017. An additional full-time employee was added in December 2018 bringing the total to nine full time employees. With the higher production volumes and reduced cost structure costs/boe are declining with $2.27/boe achieved in YTD 2018 compared to $4.52/boe in YTD 2017.

Interest and other financing costs (refer to Tables C and D on pages 9 & 10)

Finance costs Periods ended December 31	3 months Q3 2018	3 months Q3 2017	9 months YTD 2018	9 months YTD 2017
Accretion of asset retirement obligations	95	26	262	93
Interest on credit facility	201	52	590	190
Credit facility fees and costs	20	27	145	93
Total finance costs	316	105	997	376
Interest and fees –credit facility - $/boe	1.61	1.81	1.72	1.61

Finance costs include interest and lender fees plus minor amounts for miscellaneous interest and penalties charged by vendors and taxing authorities. The interest rate on the credit facility has increased as follows:

- July 2016 - from 3.70% to 5.70% - increase from 1% over prime 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.

Stock based compensation (refer to Table B on page 8)

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 at the time of grant.

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. In May 2017, 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 the new employee who commenced employment in December 2017.

Stock based compensation expense for YTD 2018 amounted to $714 compared to $532 for YTD 2017. The increase is due to additional employees and the stock options granted in May 2017. The following were used in the Black-Scholes calculations:

Nine months ended December 31	2017	2016
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.

Depletion, depreciation and impairment (refer to Table B on page 8)

The Company reviews forecast prices and the quantity of proved plus probable reserves among other factors at each period end to identify indicators of possible impairment or recovery of impairment recorded in prior periods. Such indicators did exist at March 31, 2017 and 2016 resulting in impairment for the year ended March 31, 2017 of $738 (2016 - $7,000). Should prices or reserves materially change in the future, impairment tests would again be completed and impairment or impairment recoveries recorded accordingly.

Depletion expense is a function of volume produced as it is computed on a “unit of production” basis, using total proved plus probable reserves as the depletion base. The higher production of YTD 2018 increased the depletion expense to $6,146 ($10.63 /boe) in YTD 2018 compared to $1,817 ($10.34/boe) in YTD 2017.

INCOME TAX POOLS

The Company's tax pools at March 31, 2017 (no significant changes in YTD 2018) are set out below:

Nature of tax pool	%[1]	Regular	Successor[2]	Total
Canadian exploration expense (CEE)	100	41	14,378	14,419
Canadian development expense (CDE)	30	2,764	19,879	22,643
Canadian oil and gas property expense COGPE)	10	35,491	8,883	44,374
Foreign resource expenses	10	6,601	-	6,601
Undepreciated capital cost (UCC)	25	10,504	-	10,504
Share issue costs	20	252	-	252
Non-capital losses carry forward[3]	100	31,802	-	31,802
Total tax pools		87,455	43,140	130,595

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

[2] The successor pools were acquired with one of the Q4 2017 acquisitions and can be deducted only against future profits attributable to the acquired properties.

[3] The non-capital losses carried forward expire between 2026 and 2037.

RELATED PARTY TRANSACTIONS

Related party transactions are disclosed in Note 10 of the financial statements as at and for the three and nine months ended December 31, 2017.

The Company has an agreement with the President and Chief Executive Officer which assigns a 1% gross over-riding royalty interest on all production or royalty revenue from oil or natural gas properties owned as at June 28, 2016. This royalty interest is attached to the property and transfers to the purchaser on the sale or other disposition of the property. The production subject to this royalty interest is approximately 20% of the total production for YTD 2018 resulting in gross over-riding royalties (GORR) payable to the President and Chief Executive Officer, of $49 in YTD 2018 compared to $45 in YTD 2017.

During YTD 2018 $35 (YTD 2017 - $22) was recovered for shared 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 YTD 2018.

NEW ACCOUNTING POLICIES

No new or amended accounting standards or interpretations were adopted during YTD 2018.

Accounting standards issued but not yet effective

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 the that the adoption of IFRS 15 will have a material impact on the 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. The Company continues to assess the potential impact, if any, of the adoption of IFRS 9 on the Company’s financial statements for the fiscal year ending March 31, 2019.

IFRS 16, “Leases” will come into effect for annual periods beginning on or after January 1, 2019, with earlier adoption permitted under certain conditions. 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 requires 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 assists are exempt from the requirements. Management is currently assessing the potential impact of the adoption of IFRS 16 on the Company’s financial statements.

CRITICAL ACCOUNTING ESTIMATES

The preparation of the Company’s 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 of these estimates over time. Revisions to accounting estimates are recognized in the year in which the estimates are revised and for any future years affected. A summary of the significant estimates, judgements and accounting policies used by the Company can be found in Notes 2 and 3 to the Audited Financial Statements as at and for the year ended March 31, 2017. 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 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. The Company's CGUs are listed in the following table:

Cash generating units (CGUs)	
Fiscal 2018 and future years	Fiscal 2017 and prior years
Central Alberta Gas CGU	Central Alberta Gas CGU
Central Alberta Oil CGU	Central Alberta Oil CGU
Southern Alberta Oil CGU	Southern Alberta Oil CGU 1
	Southern Alberta Oil CGU 2

A discussion of the other critical accounting estimates can be found in the Management Discussion and Analysis at March 31, 2017. Additional information is available on SEDAR at www.sedar.

OFF BALANCE SHEET ARRANGEMENTS

The Company has not engaged in any off-balance sheet arrangements. The hedge contracts for oil and natural gas prices have been disclosed on page 7 of this MD&A and are recorded at fair value as "financial instruments – commodity contracts" on the balance sheet at each period end with gains or losses recorded through earnings.

INDUSTRY CONDITIONS AND RISKS

The business of exploration, development and acquisition of oil and gas reserves involves a number of business risks inherent in the oil and gas industry which may impact the Company's results and several of which are beyond control of the Company. These business risks are operational, financial or regulatory in nature. These risks and the Company's approach to managing these issues are the same as disclosed in the Management's Discussion and Analysis for the year ended March 31, 2017. Refer to Note 11 of the Audited Financial Statements for the year ended March 31, 2017 for additional analysis of risks.

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	btu	Million British Thermal Units
boe	Barrels of oil equivalent	gj	Gigajoule
boe/d	Barrels of oil equivalent per day	Q	Quarter – three-month period
mboe	Thousand boe	YTD	Year to date – nine-month period
Q3 2018	Three months ended December 31, 2017	YTD 2018	Nine months ended December 31, 2017
Q3 2017	Three months ended December 31, 2016	YTD 2017	Nine months ended December 31, 2016

Boe - Barrel of oil equivalent is determined on the basis of 1 boe to 6 mcf of natural gas, 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

Non-IFRS 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 ("COGE Handbook") describes netback as "an operations indicator to assess operating priorities and evaluate smaller capital expenditures normally associated with field maintenance and improvement". The COGE Handbook 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 as a whole directly from the applicable amounts on the Statements of Operations in the financial statements being petroleum sales and processing fees less royalties, production and transportation costs. This amount divided by the applicable production volume (usually in boe's) provides a per unit amount.

Corporate netback is the operating netback plus or minus cash settled costs, in particular realized hedge gains (losses) and less general, administrative, interest and other financing costs. The same figures divided by the total production for the period represent net cash margin calculations for every barrel of oil equivalent sold.

Corporate netback is reconciled to "cash provided by (used in) operating activities" on the Statements of Cash Flows in the Financial Statements by adjusting for certain amounts shown on those Statements being the change in non-cash working capital for operating activities and asset retirement expenditures (if any) as follows:

	9 months	9 months
Nine months ended December 31	YTD 2018	YTD 2017
Corporate netback per Table C (page 9)	3,250	(566)
Asset retirement expenditures	(101)	-
Change in non-cash working capital for operating activities	(1,354)	563
Cash provided by (used in) operating activities	1,795	(3)

Cost per flowing barrel or barrel of oil equivalent (boe) is also a Non-GAAP measure which is computed by dividing the costs of a project (e.g. drilling or recompleting a well) or acquisition by the resulting incremental production. This measure is commonly used within the industry to measure and compare the efficiency of alternative paths to generate production.

Net debt is computed for each period end and 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, cost per flowing boe, cash flow from operations 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 junior producers in the oil and natural gas sector.

Forward-Looking Statements

The matters discussed in this 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.

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