Management's Discussion and Analysis

The following report dated November 7, 2018 is a review of the operations and current financial position for the nine months ended September 30, 2018 for Bonterra Energy Corp. ("Bonterra" or "the Company") and should be read in conjunction with the unaudited condensed financial statements and the audited financial statements including the notes related thereto for the fiscal year ended December 31, 2017 presented under International Financial Reporting Standards (IFRS).

Use of Non-IFRS Financial Measures

Throughout this Management's Discussion and Analysis (MD&A) the Company uses the terms "payout ratio", "cash netback" and "net debt" to analyze operating performance, which are not standardized measures recognized under IFRS and do not have a standardized meaning prescribed by IFRS. These measures are commonly used in the oil and gas industry and are considered informative by management, shareholders and analysts. These measures may differ from those made by other companies and accordingly may not be comparable to such measures as reported by other companies.

The Company calculates payout ratio percentage by dividing cash dividends paid to shareholders by cash flow from operating activities, both of which are measures prescribed by IFRS which appear on our statement of cash flows. We calculate cash netback by dividing various financial statement items as determined by IFRS by total production for the period on a barrel of oil equivalent basis. The Company calculates net debt as long-term debt plus working capital deficiency (current liabilities less current assets).

Frequently Recurring Terms

Bonterra uses the following frequently recurring terms in this MD&A: "WTI" refers to West Texas Intermediate, a grade of light sweet crude oil used as benchmark pricing in the United States; "MSW Stream Index" or "Edmonton Par" refers to the mixed sweet blend that is the benchmark price for conventionally produced light sweet crude oil in Western Canada; "AECO" refers to Alberta Energy Company, a grade or heating content of natural gas used as benchmark pricing in Alberta, Canada; "bbl" refers to barrel; "NGL" refers to Natural gas liquids; "MCF" refers to thousand cubic feet; "MMBTU" refers to million British Thermal Units; "GJ" refers to gigajoule; and "BOE" refers to barrels of oil equivalent. Disclosure provided herein in respect of a BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 MCF: 1 bbl is based on an energy conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Numerical Amounts

The reporting and the functional currency of the Company is the Canadian dollar.

QUARTERLY COMPARISONS

As at and for the periods ended	**2018**			2017			
($ 000s except $ per share)	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1
Financial							
Revenue - oil and gas sales	**63,817**	67,458	57,124	54,192	46,349	52,695	49,330
Cash flow from operations	**33,669**	31,908	29,877	26,472	25,491	27,370	24,540
Per share - basic and diluted	**1.01**	0.96	0.90	0.79	0.77	0.82	0.74
Payout ratio	**30%**	31%	33%	38%	40%	37%	41%
Cash dividends per share	**0.30**	0.30	0.30	0.30	0.30	0.30	0.30
Net earnings (loss)	**5,756**	8,925	3,395	2,096	(3,043)	2,978	475
Per share - basic and diluted	**0.17**	0.27	0.10	0.06	(0.09)	0.09	0.01
Capital expenditures	**18,814**	18,970	36,168	18,775 (1)	14,121	19,416	30,129
Disposition	**-**	-	-	56,752 (1)	-	-	-
Total assets	**1,137,748**	1,147,501	1,142,670	1,125,551	1,146,498	1,173,936	1,156,398
Working capital deficiency	**35,319**	27,069	46,630	27,790	28,260	29,759	39,483
Long-term debt	**293,197**	303,413	291,994	292,212	345,322	341,070	330,118
Shareholders' equity	**500,507**	503,979	504,240	510,260	517,719	529,844	535,742
Operations							
Oil (barrels per day)	**7,949**	8,743	8,034	7,766	8,038	8,287	7,533
NGLs (barrels per day)	**1,070**	984	900	963	1,000	843	813
Natural gas (MCF per day)	**24,144**	25,317	24,701	24,466	25,460	24,138	22,243
Total BOE per day	**13,043**	13,946	13,051	12,807	13,281	13,153	12,053

(1) For Q4 2017, includes the Disposition of a two percent overriding royalty interest on the total production from the Company's Pembina Cardium pool that closed December 20, 2017 and is effective January 1, 2018. Consideration consisted of $52 million of cash and incremental Cardium assets valued at $4.7 million which is included in capital expenditures (refer to Note 5 of the December 31, 2017 audited annual financial statements).

As at and for the periods ended	2016			
($ 000s except $ per share)	Q4	Q3	Q2	Q1
Financial				
Revenue - oil and gas sales	48,967	46,236	41,150	33,510
Cash flow from operations	31,537	19,219	13,392	11,146
Per share - basic and diluted	0.94	0.58	0.40	0.34
Dividend payout ratio	32%	52%	75%	89%
Cash dividends per share	0.30	0.30	0.30	0.30
Net loss	(1,168)	(5,830)	(5,582)	(11,555)
Per share - basic and diluted	(0.03)	(0.18)	(0.17)	(0.35)
Capital expenditures, net of dispositions	12,270	17,424	9,420	1,683
Total assets	1,147,834	1,163,743	1,169,782	1,174,141
Working capital deficiency	24,921	26,361	18,429	13,115
Long-term debt	329,204	335,953	336,923	345,118
Shareholders' equity	543,824	549,870	564,075	575,925
Operations				
Oil (barrels per day)	7,467	8,197	7,780	8,325
NGLs (barrels per day)	911	942	877	845
Natural gas (MCF per day)	22,540	24,948	21,771	22,274
Total BOE per day	12,134	13,298	12,285	12,882

Business Environment and Sensitivities

Bonterra's financial results are significantly influenced by fluctuations in commodity prices, including price differentials, production volumes and foreign exchange. The following table depicts selective market benchmark prices, differentials and foreign exchange rates in the last eight quarters to assist in understanding volatility in prices and foreign exchange rates that have impacted Bonterra's financial and operating performance. The increases or decreases for Bonterra's realized price for oil and natural gas for each of the eight quarters is also outlined in detail in the following table.

	Q3-2018	Q2-2018	Q1-2018	Q4-2017	Q3-2017	Q2-2017	Q1-2017	Q4-2016
Crude oil								
WTI (U.S.$/bbl)	**69.50**	67.88	62.87	55.40	48.30	48.28	51.91	49.29
WTI to MSW Stream Index								
Differential (U.S.$/bbl)[(1)]	**(6.83)**	(5.45)	(5.89)	(1.14)	(2.89)	(2.26)	(3.60)	(3.09)
Foreign exchange								
U.S.$ to Cdn$	**1.3070**	1.2911	1.2651	1.2717	1.2524	1.3447	1.3230	1.3339
Bonterra average realized								
oil price (Cdn$/bbl)	**77.20**	76.51	67.78	65.16	53.48	58.27	60.63	58.02
Natural gas								
AECO (Cdn$/mcf)	**1.19**	1.18	2.07	1.68	1.45	2.77	2.68	3.08
Bonterra average realized								
gas price (Cdn$/mcf)	**1.37**	1.16	2.24	1.90	1.81	3.03	2.97	3.32

(1) This differential accounts for the major difference between WTI and Bonterra's average realized price (before quality adjustments and foreign exchange).

The overall volatility in Bonterra's average realized commodity pricing can be impacted by numerous events or factors, including but not limited to:

- Worldwide crude oil supply and demand imbalance;
- Geo-political events that affect worldwide crude oil supply and demand;
- The value of the Canadian dollar compared to the US dollar;
- Access to infrastructure and markets;
- Weather; and
- Timing and duration of plant, refinery and pipeline maintenance.

WTI benchmark pricing which has been steadily increasing from the low of US$30.62 US per bbl in February of 2016, continued to increase throughout 2018, and is currently trading around US$65.00 per barrel. Global prices are climbing as some key, oil-producing countries are in trouble; whether it's Iran facing new sanctions or Venezuela's economic issues, both of which are likely to have less supply as a result. Around the world oil prices are on the rise, except in Alberta. A shortage of pipeline capacity and recent refinery maintenance has led to material apportionment and price weakness for Canadian light oil, making Canadian oil much cheaper relative to the US benchmark.

Oil sands production continues to climb as projects like Suncor's Fort Hills ramp up to full activity. Alberta oil supply has reached a point where there is insufficient pipeline capacity available to take it to market. Even light oil, which usually commands much higher prices than heavy oil, has been trading at discounts of up to US$30 per barrel, since all oil competes for the same pipeline space.

There is some relief in sight as the final segment of Enbridge's Line 3 replacement and expansion should be up and running at the end of next year. Completion of any of the pipeline expansion projects or increasing the country's export capabilities by expanding capacity on existing lines may have a positive effect on the movement and pricing of Canadian barrels. In addition to pipelines, industry can utilize rail to ship crude, which has grown substantially to reach record highs in the recent months. An additional 100,000 barrels per day of crude by rail is expected to commence by Q1 2019. While it is believed rail should help alleviate some backlog of oil and narrow the gap between Canadian and US prices, it is still insufficient to permanently offset the restrictions in pipeline capacity.

The AECO benchmark price for natural gas remained flat in the third quarter of 2018 and is expected to remain volatile and fluctuate for the remainder of the year, with an upward bias as we move into winter. Western Canada is nearing the end of injection season with storage levels remaining well below the five-year average. Considering the weak outlook for AECO pricing, it is worth noting that with decreasing storage levels, there is the potential to see pricing strengthen through the winter which could be magnified by cold weather. The final investment decision by LNG Canada may provide positive torque to the negative sentiment towards Western Canadian-based gas producers. While the project does not impact near-term supply/demand imbalances, it does have positive implications for the longer term.

The following chart shows the Company's sensitivity to key commodity price variables. The sensitivity calculations are performed independently and show the effect of changing one variable while holding all other variables constant.

Annualized sensitivity analysis on cash flow, as estimated for 2018 [(1)]

Impact on cash flow	Change ($)	$000s	$ per share[(2)]
Realized crude oil price ($/bbl)	1.00	2,672	0.08
Realized natural gas price ($/mcf)	0.10	928	0.03
U.S.$ to Canadian $ exchange rate	0.01	1,443	0.04

(1) This analysis uses current royalty rates, annualized estimated average production of 13,200 BOE per day and no changes in working capital
(2) Based on annualized basic weighted average shares outstanding of 33,388,796

Business Overview, Strategy and Key Performance Drivers

During the first nine months of 2018, Bonterra maintained average production at 13,347 BOE per day compared to 12,834 BOE per day for the same period in 2017, representing a production increase of four percent. The Company also experienced a 23 percent increase in cash flow from operations during the first nine months primarily due to a 22 percent increase in realized commodity prices and higher production volumes. Higher production volumes can be attributed to the Company's first quarter capital program and reactivation program targeting previous non-producing wells.

The Company averaged 13,043 BOE per day for the third quarter of 2018, compared to 13,946 BOE per day for the second quarter of 2018. The decrease in production quarter-over-quarter was a result of new wells coming on production late in the first quarter of 2018, with most of the flush production being produced in the second quarter. During Q3 2018 the Company commenced major facility turnarounds that are generally required every five years at two of its larger oil batteries, as well as a wholly-owned gas plant in the month of July that was impacted for approximately seven days. These turnarounds caused approximately 500 BOE per day to be shut in during Q3 2018. However, the Company continues to maintain its annual average production guidance of 13,200 to 13,500 BOE per day.

During the first nine months of 2018, Bonterra's production costs on a BOE basis increased to $14.58 per BOE from $12.74 per BOE for the same period in 2017. The increased production costs are attributable to the Company running four service rigs primarily in the first quarter to reactivate down wells, compared to two service rigs that would typically be running. In addition, after spring break-up, the Company commenced its lease, well and facility maintenance programs. These seasonal activities lead to higher costs which were compounded by higher power costs stemming from the retirement of coal-fired power generation facilities on April 1, 2018 as well as increased energy loads in the summer based on warm weather in Alberta. The Company also experienced higher than average water trucking charges on five of its new wells as produced water exceeded nearby injection facility capacity. These increased costs and lower volumes quarter-over-quarter resulted in increased production costs for Q3 2018 of $16.31 per BOE from $13.01 per BOE in Q2 2018. The Company anticipates lower production costs per BOE in Q4 2018 compared to Q3 2018 and expects average annual production costs to range $14.00 to $14.50 per BOE for 2018.

During the first nine months of 2018 the Company spent $73.9 million of its $75 million capital program. This is due to Bonterra's decision to heavily weight the capital program through the first five months of 2018 to maximize production prior to spring breakup when lease accessibility declines. Approximately $61.9 million was allocated to drill 27 gross operated (26.8 net) wells of which 24 gross (23.8 net) wells were completed, equipped and tied-in. The remaining $11.9 million was spent on infrastructure and non-operated wells. The annual capital spending for 2018 is now projected to be approximately $80 million. During the fourth quarter of 2018, the Company plans to drill two gross (2.0 net) wells for early production in 2019 and complete, equip and tie-in three gross (3.0 net) wells previously drilled in Q2.

On October 30, 2018, following the semi-annual review of its bank facility, the Company's borrowing base was successfully renewed at $380 million. The bank facility is comprised of a $330 million syndicated revolving credit facility, and a $50 million non-syndicated revolving credit facility. The revolving period on the bank facility expires on April 29, 2019, with a maturity date of April 30, 2020, subject to an annual review. As at September 30, 2018, Bonterra had $293 million drawn on the $380 million bank facility. These credit facilities provide the Company with sufficient liquidity and financial flexibility to execute its business plan.

Bonterra's successful operations are dependent upon several factors including, but not limited to: commodity prices, efficient management of capital spending, monthly dividends, ability to maintain desired levels of production, control over infrastructure, efficiency in developing and operating properties, and the ability to control costs. The Company's key measures of performance with respect to these drivers include but are not limited to: average daily production volumes, average realized prices, and average operating costs per unit of production. Disclosure of these key performance measures can be found in this MD&A and/or previous interim or annual MD&A disclosures.

Drilling

	Three months ended						Nine months ended			
	September 30, 2018		June 30, 2018		September 30, 2017		**September 30, 2018**		September 30, 2017	
	Gross[(1)]	**Net[(2)]**	Gross[(1)]	Net[(2)]	Gross[(1)]	Net[(2)]	**Gross[(1)]**	**Net[(2)]**	Gross[(1)]	Net[(2)]
Crude oil horizontal-operated	**7**	**6.9**	5	5.0	4	4.0	**27**	**26.8**	25	23.5
Crude oil horizontal-non-operated	**3**	**0.6**	-	-	-	-	**5**	**0.8**	6	1.5
Total	**10**	**7.5**	5	5.0	4	4.0	**32**	**27.6**	31	25.0
Success rate		**100%**		100%		100%		**100%**		100%

(1) "Gross" wells mean the number of wells in which Bonterra has a working interest.

(2) "Net" wells mean the aggregate number of wells obtained by multiplying each gross well by Bonterra's percentage of working interest.

During the first nine months of 2018, the Company drilled 27 gross (26.8 net) wells, of which 24 gross (23.9 net) wells were completed, equipped, tied-in and placed on production. The remaining three wells were brought on production in October.

In addition, five gross (0.8 net) non-operated wells were drilled, completed, equipped and on production during the first nine months of 2018.

Production

	Three months ended			Nine months ended	
	September 30, 2018	June 30, 2018	September 30, 2017	**September 30, 2018**	September 30, 2017
Crude oil (barrels per day)	**7,949**	8,743	8,038	**8,242**	7,954
NGLs (barrels per day)	**1,070**	984	1,000	**985**	886
Natural gas (MCF per day)	**24,144**	25,317	25,460	**24,719**	23,959
Average BOE per day	**13,043**	13,946	13,281	**13,347**	12,834

Production increased for the first nine months of 2018 compared to the same period a year ago, primarily due to very positive second quarter production volumes. With increased crude oil prices, Bonterra placed a strong focus on bringing new wells on production earlier in the year. As a result, of the 24 (23.9 net) wells that were placed on production in the first nine months of 2018, 75 percent were on production by the end of April. This is a substantial increase, compared to 58 percent of the 24 (21.1 net) wells that were placed on production before the end of April, 2017.

In Q3 2018, production volumes decreased by 903 BOE per day compared to Q2 2018. This was primarily due to more new production volumes coming on-stream during Q2 2018 and approximately 500 BOE per day of shut in production in the third quarter. The majority of the shut-in production was a result of major facility turnarounds at Bonterra's operated facilities along with some turnarounds and restrictions at third party facilities and pipelines.

Cash Netback

The following table illustrates the calculation of the Company's cash netback from operations for the periods ended:

	Three months ended			Nine months ended	
$ per BOE	**September 30, 2018**	June 30, 2018	September 30, 2017	**September 30, 2018**	September 30, 2017
Production volumes (BOE)	**1,199,929**	1,269,114	1,221,852	**3,643,642**	3,503,560
Gross production revenue	**53.18**	53.15	37.93	**51.71**	42.35
Royalties	**(6.17)**	(5.45)	(2.59)	**(5.51)**	(2.92)
Production costs	**(16.31)**	(13.01)	(12.54)	**(14.58)**	(12.74)
Field netback	**30.70**	34.69	22.80	**31.62**	26.69
General and administrative	**(1.45)**	(1.67)	(1.72)	**(1.61)**	(1.75)
Interest and other	**(2.94)**	(2.96)	(3.49)	**(3.18)**	(3.46)
Cash netback	**26.31**	30.06	17.59	**26.83**	21.48

Cash netbacks for the first nine months of 2018 compared to the same period a year ago increased by $5.35 per BOE. This is primarily due to the increase in commodity prices being partially offset by an increase in royalty rates for the two percent gross overriding royalty (GORR) on the Pembina Cardium pool assets effective January 1, 2018 and an increase in production costs.

Quarter-over-quarter, cash netbacks decreased due to higher production costs from increased repairs and maintenance plus road and lease costs that typically occur after spring breakup. In addition, power costs spiked in the third quarter due to the retirement of coal-fired power generation facilities on April 1 and higher demand loads in the summer based on warm weather in Alberta.

Oil and Gas Sales

	Three months ended			Nine months ended	
	September 30, 2018	June 30, 2018	September 30, 2017	**September 30, 2018**	September 30, 2017
Revenue - oil and gas sales ($ 000s)					
Crude oil	**56,457**	60,869	39,596	**166,336**	124,910
NGL	**4,325**	3,912	2,539	**11,372**	6,820
Natural gas	**3,035**	2,677	4,214	**10,692**	16,644
	63,817	67,458	46,349	**188,400**	148,374
Average realized prices:					
Crude oil ($ per barrel)	**77.20**	76.51	53.48	**73.93**	57.38
NGLs ($ per barrel)	**43.95**	43.69	27.81	**42.28**	28.67
Natural gas ($ per MCF)	**1.37**	1.16	1.81	**1.58**	2.58
Average ($ per BOE)	**53.18**	53.15	37.93	**51.71**	42.35
Average BOE per day	**13,043**	13,946	13,281	**13,347**	12,834

Revenue from oil and gas sales for the first nine months of 2018 increased by $40,026,000, or 27 percent, compared to the same period a year ago. The increase in oil and gas sales was primarily driven by higher production and commodity prices for oil and NGLs. The quarter- over-quarter decrease in oil and gas sales was primarily due to a decrease in production volumes.

The Company's product split on a revenue basis for 2018 year to date is weighted approximately 94 percent crude oil and NGLs.

Royalties

($ 000s)	Three months ended September 30, 2018	June 30, 2018	September 30, 2017	Nine months ended September 30, 2018	September 30, 2017
Crown royalties	**4,784**	4,090	2,299	**12,681**	7,265
Freehold, gross overriding and other royalties	**2,616**	2,820	865	**7,411**	2,965
Total royalties	**7,400**	6,910	3,164	**20,092**	10,230
Crown royalties - percentage of revenue	**7.5**	6.1	5.0	**6.7**	4.9
Freehold, gross overriding and other royalties - percentage of revenue	**4.1**	4.2	1.9	**3.9**	2.0
Royalties - percentage of revenue	**11.6**	10.3	6.9	**10.6**	6.9
Royalties $ per BOE	**6.17**	5.45	2.59	**5.51**	2.92

Royalties paid by the Company consist of crown royalties to the Provinces of Alberta, Saskatchewan and British Columbia and other royalties. Total royalties on a per BOE basis increased by $2.59 per BOE for the first nine months of 2018 compared to the same period in 2017. The increase in royalties is primarily due to the two percent GORR transaction on the Pembina Cardium pool assets along with an overall increase in commodity prices. The quarter-over-quarter increase in royalties of $0.72 per BOE was due to an increase in crown royalties for crude oil in Alberta. The crude oil reference price used to calculate Alberta crown royalties on crude oil increased by approximately 15 percent despite Bonterra's realized price for crude oil remaining relatively static over the last two quarters. The Company expects crown royalties as a percentage of revenue to decrease in the fourth quarter as the crude oil reference price (which is a trailing price) for Alberta Crown royalties has decreased.

Production Costs

($ 000s except $ per BOE)	Three months ended September 30, 2018	June 30, 2018	September 30, 2017	Nine months ended September 30, 2018	September 30, 2017
Production costs	**19,572**	16,517	15,319	**53,115**	44,638
$ per BOE	**16.31**	13.01	12.54	**14.58**	12.74

Production costs for the first nine months of 2018 increased by $1.84 per BOE compared to the first nine months of 2017. Higher costs are attributable to the Company employing four service rigs during the first quarter of 2018 to reactivate non-producing down wells and take advantage of higher commodity prices as well as avoid pending road bans. This compares to two service rigs the Company would have running for the same period historically.

Production costs for Q3 2018 increased by $3.30 per BOE compared to the previous quarter. The third quarter is generally when most producers in Alberta undertake facility turnarounds. These seasonal activities incur higher costs which were compounded by several other factors, including higher water trucking charges on five new wells, as produced water exceeded nearby injection facility capacity and higher power costs following the retirement of coal-fired power generation facilities on April 1. These increases were further affected by warm weather in Alberta which increased energy loads in the summer. These increased costs along with reduced production volumes quarter-over-quarter resulted in increased production costs for Q3 2018 of $16.31 per BOE compared to $13.01 per BOE in Q2 2018.

Bonterra anticipates production costs per BOE will be lower in Q4 2018 compared to Q3 2018 with expected average annual production costs to range $14.00 to $14.50 per BOE for 2018.

Other Income

	Three months ended			Nine months ended	
	September 30,	June 30,	September 30,	**September 30,**	September 30,
($ 000s)	**2018**	2018	2017	**2018**	2017
Investment income	**21**	(72)	18	**48**	41
Administrative income	**39**	42	85	**133**	189
Deferred consideration	**332**	383	-	**1,060**	-
	392	353	103	**1,241**	230

In the fourth quarter of 2017, Bonterra sold a two percent overriding royalty interest on the total production from the Company's Pembina Cardium pool with an effective date of January 1, 2018. Consideration received on disposition was $56,747,000, comprised of $52,000,000 in cash plus property, plant and equipment valued at $4,747,000. The result of this disposition was a gain on disposal of $4,226,000 and deferred consideration of $16,064,000, of which $1,060,000 was recognized in the first nine months of 2018.

The market value of the investments held by the Company at September 30, 2018 was $530,000 (September 30, 2017 - $941,000). The carrying value decreased due to a reduction in the investments' carrying value. There were no dispositions for the nine months ended September 30, 2018 or 2017. Dispositions that result in a gain or loss on sale are recorded as an equity transfer between accumulated other comprehensive income and retained earnings.

The Company receives administrative income for various oil and gas administrative services and production equipment rentals.

General and Administration (G&A) Expense

	Three months ended			Nine months ended	
	September 30,	June 30,	September 30,	**September 30,**	September 30,
($ 000s except $ per BOE)	**2018**	2018	2017	**2018**	2017
Employee compensation expense	**1,202**	1,370	959	**3,937**	3,528
Office and administrative expense	**534**	747	1,137	**1,946**	2,603
Total G&A expense	**1,736**	2,117	2,096	**5,883**	6,131
$ per BOE	**1.45**	1.67	1.72	**1.61**	1.75

The increase of $409,000 in employee compensation expense for the first nine months of 2018 compared to the same period in 2017 is primarily due to a higher bonus accrual from increased earnings before income taxes. The Company has a bonus plan in which the bonus pool consists of a range between 2.5 percent to 3.5 percent of earnings before income taxes. The Company firmly believes that tying employee compensation (including the use of stock options) to corporate performance clearly aligns the interests of the employees with those of shareholders.

Office and administrative expenses for the first nine months of 2018 decreased by $657,000 compared to the same period in 2017 primarily due to a reduction in consulting fees and a decrease in the allowance for doubtful accounts expense.

Finance Costs

	Three months ended			Nine months ended	
	September 30,	June 30,	September 30,	**September 30,**	September 30,
($ 000s except $ per BOE)	**2018**	2018	2017	**2018**	2017
Interest on long-term debt	**3,352**	3,504	4,142	**11,116**	11,678
Other interest	**230**	217	231	**666**	664
Interest expense	**3,582**	3,721	4,373	**11,782**	12,342
$ per BOE	**2.99**	2.93	3.58	**3.23**	3.52
Unwinding of the discounted value of decommissioning liabilities	**789**	761	763	**2,307**	2,252
Total finance costs	**4,371**	4,482	5,136	**14,089**	14,594

Interest on long-term debt decreased in the first nine months of 2018 compared to the same period in 2017 due to the Company carrying average long-term debt that was lower by $31,500,000. Interest rates for the current quarter are determined based on the trailing quarter and calculated by taking the ratio of total debt (excluding accounts payable and accrued liabilities) to EBITDA (defined as net income excluding finance costs, provision for current and deferred taxes, depletion and depreciation, share-option compensation, gain or loss on sale of assets and impairment of assets) multiplied by four.

Other interest relates primarily to amounts paid to a related party (see related party transactions) and a $10,000,000 subordinated promissory note from a private investor. For more information about the subordinated promissory note, refer to Note 5 of the September 30, 2018 condensed financial statements.

A one percent increase (decrease) in the Canadian prime rate would decrease (increase) both annual net earnings and comprehensive income by approximately $2,228,000.

Share-Option Compensation

	Three months ended			Nine months ended	
	September 30,	June 30,	September 30,	**September 30,**	September 30,
($ 000s)	**2018**	2018	2017	**2018**	2017
Share-option compensation	**753**	766	1,029	**2,261**	3,907

Share-option compensation is a statistically calculated value representing the estimated expense of issuing employee stock options. The Company records a compensation expense over the vesting period based on the fair value of options granted to employees, directors and consultants.

Share-option compensation decreased by $1,646,000 from a year ago. This decline is due to most of the options issued in 2016 (that were fully amortized in 2017) having a higher share price volatility than those options issued in the fourth quarter of 2017 (which are amortizing in 2018).

Based on the outstanding options as of September 30, 2018, the Company has an unamortized expense of $1,428,000, of which $361,000 will be recorded for the remainder of 2018; $1,014,000 for 2019; and $53,000 thereafter. For more information about options issued and outstanding, refer to Note 8 of the September 30, 2018 condensed financial statements.

Depletion and Depreciation, Exploration and Evaluation (E&E) and Goodwill

	Three months ended			Nine months ended	
	September 30,	June 30,	September 30,	**September 30,**	September 30,
($ 000s)	**2018**	2018	2017	**2018**	2017
Depletion and depreciation	**22,288**	24,526	22,349	**68,264**	66,427
Exploration and evaluation	**-**	-	-	**291**	-

The provision for depletion and depreciation increased for the first nine months of 2018 compared to the first nine months of 2017 due to increased production volumes and higher capital spending. The quarter-over-quarter decrease in depletion and depreciation is due to a decrease in production volumes.

Exploration and evaluation expense related to expired leases.

There were no impairment provisions recorded for the three and nine months ended September 30, 2018 and 2017.

Taxes

The Company recorded income tax expense of $7,570,000 for the first nine months of 2018 (2017 – $2,267,000). The increase in income tax expense is due to an increase in net earnings before income taxes. Included in current income tax expense is $1,076,000 (2017 - $Nil) of provincial income taxes that was recognized and included in accounts payable and accrued liabilities for the nine months ended September 30, 2018.

For additional information regarding income taxes, see Note 7 of the September 30, 2018 condensed financial statements.

Net Earnings

	Three months ended			Nine months ended	
	September 30,	June 30,	September 30,	**September 30,**	September 30,
($ 000s except $ per share)	**2018**	2018	2017	**2018**	2017
Net earnings	**5,756**	8,925	(3,043)	**18,076**	410
$ per share - basic	**0.17**	0.27	(0.09)	**0.54**	0.01
$ per share - diluted	**0.17**	0.27	(0.09)	**0.54**	0.01

Net earnings for the first nine months of 2018 increased by $17,666,000 compared to the first nine months of 2017. The increase in net earnings was mainly due to increased commodity prices for oil and NGLs and production volumes. The increase in net earnings was partially offset by an increase in royalties, production costs and income tax expense.

The quarter-over-quarter decrease in net earnings was mainly due to a decrease in oil and gas production and an increase in production costs, which was partially offset by a decrease in depletion and depreciation and income tax expense.

Other Comprehensive Income (Loss)

Other comprehensive income for 2018 consists of an unrealized loss before tax on investments (including investment in a related party) of $221,000 relating to a decrease in the investments' fair value (September 30, 2017 – unrealized loss of $680,000). Realized gains decrease accumulated other comprehensive income as these gains are transferred to retained earnings. Other comprehensive income varies from net earnings by unrealized changes in the fair value of Bonterra's holdings of investments including the investment in a related party, net of tax.

Cash Flow from Operations

	Three months ended			Nine months ended	
	September 30,	June 30,	September 30,	**September 30,**	September 30,
($ 000s except $ per share)	**2018**	2018	2017	**2018**	2017
Cash flow from operations	**33,669**	31,908	25,491	**95,454**	77,401
$ per share - basic	**1.01**	0.96	0.77	**2.87**	2.32
$ per share - diluted	**1.01**	0.96	0.77	**2.87**	2.32

In the first nine months of 2018, cash flow from operations increased by $18,053,000 compared to the same period a year ago. This was primarily due to an increase in revenue from oil and gas sales, which was partially offset by an increase in royalties and production costs.

The quarter-over-quarter increase in cash flow of $1,760,000 is primarily due to an increase in non-cash working capital, which was partially offset by a decrease in oil and gas production and an increase in royalties and production costs.

Related Party Transactions

Bonterra holds 1,034,523 (December 31, 2017 – 1,034,523) common shares in Pine Cliff Energy Ltd. ("Pine Cliff") which represents less than one percent ownership in Pine Cliff's outstanding common shares. Pine Cliff's common shares had a fair market value as of September 30, 2018 of $321,000 (December 31, 2017 of $476,000). The Company provides executive and marketing services for Pine Cliff. All services that were performed were charged at estimated fair value. As at September 30, 2018, the Company had an account receivable from Pine Cliff of $39,000 (December 31, 2017 – $36,000).

As at September 30, 2018, the Company's CEO, Chairman of the Board and major shareholder has loaned the Company $12,000,000 (December 31, 2017 - $12,000,000). The loan bears interest at Canadian chartered bank prime less 5/8th of a percent and has no set repayment terms but is payable on demand. Security under the debenture is over all of the Company's assets and is subordinated to any and all claims in favour of the syndicate of senior lenders providing credit facilities to the Company. The Company's bank agreement requires that the above loan can only be repaid should the Company have sufficient available borrowing limits under the Company's credit facility. Interest paid on this loan for the first nine months of 2018 was $261,000 (September 30, 2017 - $196,000). This loan results in a benefit to Bonterra as the interest paid to the CEO by Bonterra is lower than bank interest.

Liquidity and Capital Resources

Net Debt to Cash Flow from Operations

Bonterra continues to focus on monitoring overall debt while managing its cash flow, capital expenditures and dividend payments. The Company's net debt to twelve-month trailing cash flow ratio as of September 30, 2018 was 2.7 to 1 times (versus 3.1 to 1 times at December 31, 2017). The reduction in net debt to cash flow ratio is due to an increase in cash flow, partially offset by an increase in net debt stemming from investing nearly all of Bonterra's 2018 capital expenditure program by the end of the third quarter of 2018. The Company reduced net debt by $1,966,000 in the third quarter due to increased cash flow from new wells, higher oil and NGL prices and maintaining capital expenditures comparable to the second quarter, representing approximately half of the capital spent in the first quarter of 2018. The Company's primary focus is to manage its bank debt during a period of volatile commodity prices. Bonterra will continue to assess its dividend and capital expenditures compared to cash flow from operations on a quarterly basis.

Working Capital Deficiency and Net debt

($ 000s)	**September 30, 2018**	June 30, 2018	December 31, 2017	September 30, 2017
Working capital deficiency	**35,319**	27,069	27,790	28,260
Long-term bank debt	**293,197**	303,413	292,212	345,322
Net Debt	**328,516**	330,482	320,002	373,582

The Company has sufficient availability on its credit facility to repay both the related party loan and the subordinated promissory note, if required. During each quarter, the Company manages net debt by monitoring capital spending and dividends paid compared to cash flow from operations.

Net debt is a combination of long-term bank debt and working capital. Net debt for September 30, 2018 increased by $8,514,000 from December 31, 2017 primarily due to the accelerated capital program in the first quarter. Quarter-over-quarter net debt decreased by $1,966,000 primarily due to an increase in cash flows from operating activities.

Working capital is calculated as current liabilities less current assets. The Company finances its working capital deficiency using cash flow from operations, its long-term bank facility, share issuances, option exercises and adjustments of dividend payments. Included in the working capital deficiency as at September 30, 2018 is $22,000,000 million of debt relating to the subordinated promissory note and the amount due to a related party.

Financial Risk Management

The Company has entered into physical delivery sales contracts to manage commodity risk. These contracts are considered normal sales contracts and are not recorded at fair value in the financial statements. For more information on physical delivery contracts in place see Note 10 of the September 30, 2018 condensed financial statements.

Capital Expenditures

During the nine months ended September 30, 2018, the Company incurred capital expenditures of $73,952,000 (September 30, 2017 - $63,666,000). The costs relate to drilling 27 gross (26.8 net) wells with related infrastructure costs, of which 24 gross (23.9 net) wells were completed, equipped, tied-in and placed on production. The remaining three wells were brought on production in October of 2018. In addition, five gross (0.8 net) non-operated wells were drilled, completed, equipped and on production during the first nine months of 2018.

Liability Management Ratio ("LMR") Update

In the first nine months of 2018, 94.9 percent of the Company's production was in the province of Alberta. The Company currently has an LMR rating of 2.08 in Alberta and does not expect that with its current LMR there will be any regulatory impediments to completing future potential acquisitions.

Long-term Debt

Long-term debt represents the outstanding draws from the Company's bank facility as described in the notes to the Company's audited annual financial statements. As of September 30, 2018, the Company has a bank facility with a limit of $380,000,000 (December 31, 2017 - $380,000,000) that is comprised of a $330,000,000 syndicated revolving credit facility and a $50,000,000 non-syndicated revolving credit facility. Amounts drawn under this bank facility at September 30, 2018 totaled $293,197,000 (December 31, 2017 - $292,212,000). The interest rates for the nine months ended September 30, 2018 on the Company's Canadian prime rate loan and Banker's Acceptances are between four to six percent. The loan is revolving to April 29, 2019 with a maturity date of April 30, 2020, subject to annual review. The credit facilities have no fixed terms of repayment.

The available lending limits of the credit facilities are reviewed semi-annually on or before April 30 and October 31 each year based mainly on the lender's assessment of the Company's reserves, future commodity prices and costs. On October 30, 2018, the Company successfully renewed its available lending limit at $380,000,000.

Advances drawn under the bank facility are secured by a fixed and floating charge debenture over the assets of the Company. In the event the bank facility is not extended or renewed, amounts drawn under the facility would be due and payable on the maturity date. The size of the committed credit facilities is based primarily on the value of the Company's producing petroleum and natural gas assets and related tangible assets as determined by the lenders. For more information see Note 6 of the September 30, 2018 condensed financial statements.

Shareholders' Equity

The Company is authorized to issue an unlimited number of common shares without nominal or par value.

The Company is authorized to issue an unlimited number of Class "A" redeemable Preferred Shares and an unlimited number of Class "B" Preferred Shares. There are currently no outstanding Class "A" redeemable Preferred Shares or Class "B" Preferred Shares.

Issued and fully paid - common shares	**Number**	**Amount ($ 000s)**
Balance, beginning of year	**33,310,796**	**763,977**
Issued pursuant to the Company's share option plan	**5,000**	**81**
Transfer from contributed surplus to share capital		**12**
Balance, September 30, 2018	**33,315,796**	**764,070**

The Company provides a stock option plan for its directors, officers, employees and consultants. Under the plan, the Company may grant options for up to 3,331,580 (December 31, 2017 – 3,331,080) common shares. The exercise price of each option granted will not be lower than the market price of the common shares on the date of grant and the option's maximum term is five years. For additional information regarding options outstanding, see Note 8 of the September 30, 2018 condensed financial statements.

Dividend Policy

For the three months ended September 30, 2018, the Company declared and paid dividends of $9,994,000 ($0.30 per share) (September 30, 2017 – $9,993,000) ($0.30 per share). For the nine months ended September 30, 2018 the Company declared and paid dividends of $29,980,000 ($0.90 per share) (September 30, 2017 - $29,978,000 ($0.90 per share)). Bonterra's dividend policy is regularly monitored and is dependent upon production, commodity prices, cash flow from operations, debt levels and capital expenditures. With its large inventory of undrilled locations, Bonterra continues to be well positioned to provide its shareholders with a combination of sustainable growth and meaningful dividend income. Bonterra's dividend payout ratio based on cash flow from operations was 31 percent for the nine months ended September 30, 2018 (39 percent for the nine months ended September 30, 2017).

Bonterra's capital spending and dividends to its shareholders are funded by cash flow from operating activities with the remaining free cash flow directed to debt repayment. To the extent that the excess cash flow from operations after dividends and capital spending is not sufficient, the shortfall may be funded by drawdowns on Bonterra's bank facility. Bonterra intends to provide dividends to shareholders that are sustainable by the Company with consideration to its liquidity and long-term operational strategy. The level of dividends is highly dependent upon cash flow generated from operations, which may fluctuate significantly due to changes in financial and operational performance, commodity prices, interest and exchange rates and many other factors. As such future dividends cannot be assured.

Quarterly Financial Information

	2018			2017			
For the periods ended ($ 000s except $ per share)	**Q3**	**Q2**	Q1	Q4	Q3	Q2	Q1
Revenue - oil and gas sales	**63,817**	67,458	57,124	54,192	46,349	52,695	49,330
Cash flow from operations	**33,669**	31,908	29,877	26,472	25,491	27,370	24,540
Net earnings (loss)	**5,756**	8,925	3,395	2,096	(3,043)	2,978	475
Per share - basic	**0.17**	0.27	0.10	0.06	(0.09)	0.09	0.01
Per share - diluted	**0.17**	0.27	0.10	0.06	(0.09)	0.09	0.01

	2016			
For the periods ended ($ 000s except $ per share)	Q4	Q3	Q2	Q1
Revenue - oil and gas sales	48,967	46,236	41,150	33,510
Cash flow from operations	31,537	19,219	13,392	11,146
Net loss	(1,168)	(5,830)	(5,582)	(11,555)
Per share - basic	(0.03)	(0.18)	(0.17)	(0.35)
Per share - diluted	(0.03)	(0.18)	(0.17)	(0.35)

The fluctuations in the Company's revenue and net earnings from quarter-to-quarter are caused by variations in production volumes, realized commodity pricing and the related impact on royalties, production, G&A and finance costs. In the first three quarters of 2016, net earnings and cash flow were lower than most other periods due to a significant decrease in commodity prices.

Critical Accounting Estimates

There have been no changes to the Company's critical accounting policies and estimates as of the period ended in the financial statements.

Forward-Looking Information

Certain statements contained in this MD&A include statements which contain words such as "anticipate", "could", "should", "expect", "seek", "may", "intend", "likely", "will", "believe" and similar expressions, relating to matters that are not historical facts, and such statements of our beliefs, intentions and expectations about development, results and events which will or may occur in the future, constitute "forward-looking information" within the meaning of applicable Canadian securities legislation and are based on certain assumptions and analysis made by us derived from our experience and perceptions. Forward-looking information in this MD&A includes, but is not limited to: expected cash provided by continuing operations; cash dividends; future capital expenditures, including the amount and nature thereof; oil and natural gas prices and demand; expansion and other development trends of the oil and gas industry; business strategy and outlook; expansion and growth of our business and operations; and maintenance of existing customer, supplier and partner relationships; supply channels; accounting policies; credit risks; and other such matters.

All such forward-looking information is based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions and expected future developments, as well as other factors we believe are appropriate in the circumstances. The risks, uncertainties, and assumptions are difficult to predict and may affect operations, and may include, without limitation: foreign exchange fluctuations; equipment and labour shortages and inflationary costs; general economic conditions; industry conditions; changes in applicable environmental, taxation and other laws and regulations as well as how such laws and regulations are interpreted and enforced; the ability of oil and natural gas companies to raise capital; the effect of weather conditions on operations and facilities; the existence of operating risks; volatility of oil and natural gas prices; oil and gas product supply and demand; risks inherent in the ability to generate sufficient cash flow from operations to meet current and future obligations; increased competition; stock market volatility; opportunities available to or pursued by us; and other factors, many of which are beyond our control. The foregoing factors are not exhaustive.

Actual results, performance or achievements could differ materially from those expressed in, or implied by, this forward-looking information and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking information will transpire or occur, or if any of them do, what benefits will be derived therefrom. Except as required by law, Bonterra disclaims any intention or obligation to update or revise any forward-looking information, whether as a result of new information, future events or otherwise.

The forward-looking information contained herein is expressly qualified by this cautionary statement.

Internal Controls Over Financial Reporting

The Company is required to comply with National Instrument 52-109 "Certification of Disclosure in Issuers' Annual and Interim Filings." The certification of interim filings for the interim period ended September 30, 2018 requires that Bonterra disclose in the interim MD&A any changes in the Company's internal control over financial reporting that occurred during the period that have materially affected, or are reasonably likely to materially affect, the Company's internal control over financial reporting. Bonterra confirms that no such changes were made to its internal controls over financial reporting during the nine months ended September 30, 2018.

Additional information relating to the Company may be found on www.sedar.com or visit our website at www.bonterraenergy.com.