Bonterra Energy Corp.

For the three and six months ended June 30, 2021

TSX: **BNE**
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BONTERRA ENERGY REPORTS SECOND QUARTER AND SIX MONTHS ENDED JUNE 30, 2021 FINANCIAL AND OPERATING RESULTS

HIGHLIGHTS

		Three months ended		Six months ended	
As at and for the periods ended		**June 30,**	June 30,	**June 30,**	June 30,
($ 000s except for $ per share and $ per BOE)		**2021**	2020	**2021**	2020
FINANCIAL					
Revenue - realized oil and gas sales		**59,163**	22,171	**107,957**	60,726
Funds flow (1)		**23,105**	4,185	**39,697**	18,855
Per share - basic		**0.69**	0.13	**1.18**	0.56
Per share - diluted		**0.67**	0.13	**1.16**	0.56
Cash flow from operations		**18,874**	4,429	**33,619**	26,902
Per share - basic		**0.56**	0.13	**1.00**	0.81
Per share - diluted		**0.55**	0.13	**0.98**	0.81
Net earnings (loss)(2)		**157,354**	(5,954)	**155,670**	(290,607)
Per share - basic		**4.68**	(0.18)	**4.63**	(8.70)
Per share - diluted		**4.55**	(0.18)	**4.53**	(8.70)
Capital expenditures		**7,607**	104	**31,068**	21,845
Total assets				**948,260**	732,462
Net debt(3)				**319,310**	299,445
Working capital deficiency				**273,141**	299,445
Long-term debt				**46,169**	-
Shareholders' equity				**353,431**	212,342
OPERATIONS					
Light oil	-barrels (bbl) per day	**7,370**	5,553	**7,103**	6,306
	-average price ($ per bbl)	**71.49**	33.31	**66.84**	42.47
NGLs	-bbl per day	**996**	1,104	**1,011**	1,052
	-average price ($ per bbl)	**35.59**	12.14	**35.59**	15.50
Conventional natural gas	- MCF per day	**26,057**	21,142	**25,184**	22,503
	- average price ($ per MCF)	**3.37**	2.14	**3.40**	2.20
Total barrels of oil equivalent per day (BOE)(4)		**12,709**	10,181	**12,311**	11,108

(1) Funds flow is not a recognized measure under IFRS. For these purposes, the Company defines funds flow as funds provided by operations including proceeds from sale of investments and investment income received excluding the effects of changes in non-cash working capital items and decommissioning expenditures settled.

(2) In the first quarter of 2020 the Company recorded a $331,678,000 impairment provision less a $54,107,000 deferred income tax recovery related to its Alberta CGU's oil and gas assets due to the impact of COVID-19 effect on the forward benchmark prices for crude oil. With stronger forward prices in Q2 2021, the Company recorded a $203,197,000 impairment reversal on its Alberta CGU's oil and gas assets less $47,149,000 deferred income tax expense.

(3) Net debt is not a recognized measure under IFRS. The Company defines net debt as current liabilities less current assets plus long-term subordinated debt.

(4) 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.

REPORT TO SHAREHOLDERS

Bonterra Energy Corp. (Bonterra or the Company) is pleased to present our second quarter 2021 financial and operating results, selected highlights from which are provided below. Readers are encouraged to review in conjunction with the Company's full Q2 2021 report which has been filed on SEDAR and is available on Bonterra's website.

Q2 2021 FINANCIAL & OPERATING SNAPSHOT

- Production averaged 12,709 BOE per day in Q2 2021, 25 percent higher than in Q2 2020, the result of a successful drilling program that re-commenced in the fourth quarter of 2020, along with the reactivation of wells that had been voluntarily shut-in due to low commodity prices.
- Realized oil and gas sales increased 167 percent over Q2 2020 to total $59.2 million in Q2 2021, due primarily to higher realized crude oil prices and growing production volumes.
- Funds flow[1] of $23.1 million in the quarter ($0.67 per fully diluted share) was 452 percent higher than Q2 2020, and 39 percent higher than Q1 2021.
- Cost savings remained a priority across the organization, with Bonterra reducing Q2 2021 production costs per unit to $14.98 per BOE, four percent lower than the preceding quarter.
- Drilling, completion and equipping costs in the first half of 2021 decreased by approximately 35 percent year-over-year to average $2.1 million per well.
- Field netbacks[1] averaged $27.59 per BOE in Q2 2021, a 194 percent increase over Q2 2020, reflecting significantly higher per unit revenue offset by realized losses on risk management contracts and increased per unit royalty expenses.
- Capital expenditures of $31.0 million in the first half of 2021 contributed to the drilling of 16 gross (15.9 net) wells and the completion, equip, tie-in and placing on production of 20 gross (19.7 net) wells, with four of the completed and equipped wells having been drilled late in 2020. The balance was spent primarily on related infrastructure and recompletions.
- Net debt[1] totaled $319.3 million as at June 30, 2021, a $3.7 million increase from year-end 2020, reflecting the impact of a more active capital program that is designed to return production to pre-COVID-19 levels. As at June 30, 2021, Bonterra had drawn $244 million on the $265 million syndicated bank facility.

Since the beginning of 2021, the Company has benefitted from increasing crude oil and natural gas prices as stability returns to global commodity markets following severe volatility through most of 2020. During the second quarter of 2021, Bonterra introduced new production volumes into a much higher commodity price environment which resulted in realized average oil prices of $71.49 per bbl in the quarter, an increase of 115 percent over Q2 2020 prices. In addition, the Company's average realized NGL price was $35.59 per bbl, or 193 percent higher than the same period in 2020, while the average realized natural gas price of $3.37 per mcf was 57 percent higher. This price improvement helped to drive meaningful growth in netbacks in the second quarter of 2021, with field and cash netbacks of $27.59 per BOE and $19.98 per BOE, respectively, compared to $9.40 per BOE and $4.52 per BOE in Q2 2020, respectively. Bonterra will continue to regularly monitor commodity price changes and funds flow with the primary objective of reducing bank debt while continuing to add production and grow reserves value.

[1] "Funds Flow", "Field Netback" and "Net Debt" are not recognized measures under IFRS.

In concert with realizing higher prices during the second quarter of 2021, Bonterra also benefited from stronger production volumes, which averaged 12,709 BOE per day, an increase of seven percent over the preceding quarter, and 25 percent over the same period of 2020. Throughout the first half of 2021, the Company invested a total of $31.0 million of capital, or approximately 48 percent of the lower end of our full year capital budget range, with $24.6 million allocated to drilling, completion, equip and tie-in activities. This resulted in 16 gross (15.9 net) wells being drilled and 20 gross (19.7 net) wells being completed, equipped, tied-in and placed on production, with four of the completed and equipped wells having been drilled late in 2020. Approximately $6.4 million was allocated primarily to related infrastructure and recompletions.

As a result of the Company's 2021 capital program, wells that had been drilled, completed and brought on production through the first quarter of the year benefited Bonterra by contributing volumes for a full quarter in Q2 2021. The majority of the production volumes coming from new wells was brought online through March and April of 2021. These higher volumes helped reduce per unit production costs in the quarter, which averaged $14.98 per BOE compared to $15.60 per BOE in the previous quarter despite higher absolute costs, and were $13.84 per BOE in Q2 2020, reflecting very low levels of activity in that period.

As at June 30, 2021, Bonterra's net debt totaled $319.3 million, including $244 million drawn on our $265 million bank facility. Just prior to quarter end, the Company's syndicate of Canadian financial institutions redetermined Bonterra's credit facility at $265 million, a reduction from the $300 million previously in place.

In addition to undertaking new drilling to date in 2021, Bonterra also remained committed to efficiently manage decommissioning liabilities, having abandoned 137.3 net wells during the first six months of this year, supported by the Alberta Site Rehabilitation Program ("SRP"). As Bonterra continues to advance our abandonment program through the remainder of this year and next, it is estimated that a further 170.5 net wells with no deemed future potential can be abandoned.

OUTLOOK

During the third quarter of 2021, approximately eight gross (6.9 net) operated wells are expected to be drilled and completed as Bonterra continues to execute our capital expenditure program. In light of the successful execution of the capital program to date, combined with favourable price forecasts and positive well performance, the Company anticipates average production for 2021 will be within our previously announced annual guidance range of 12,800 to 13,200 BOE per day.

As part of Bonterra's ongoing efforts to diversify commodity prices and protect future cash flows, the Company has put in place physical delivery sales and risk management contracts to the end of June 30, 2022. Through subsequent quarters, Bonterra can continue to participate in upward oil price movements while mitigating market volatility and locking-in economics given approximately 30 percent of forecast volumes are hedged.

Financial discipline and cost control continue to be priorities for Bonterra, and the Company remains committed to reducing bank debt and strengthening the balance sheet, while continuing to add reserve value, particularly into rising commodity prices. Bonterra believes the Company is strategically positioned to drive profitable growth through this period of improving oil and natural gas markets by prudently developing our high-quality, light oil weighted asset base and directing excess funds flow to a combination of debt repayment plus modest growth. The Company continues to prioritize environmental, social and governance ("ESG") initiatives, including being a positive and meaningful contributor to the economic and social success of the communities where it operates in central Alberta, upholding a responsible abandonment and reclamation program, and maintaining stringent safety measures for all employees, contractors and partners.

George F. Fink
Chief Executive Officer

Management's Discussion and Analysis

The following report dated August 11, 2021 is a review of the operations and current financial position for the three and six months ended June 30, 2021 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, 2020 presented under International Financial Reporting Standards (IFRS), as well as Bonterra's Annual Information Form ("AIF"), each of which is filed on SEDAR at www.sedar.com.

Use of Non-IFRS Financial Measures

Throughout this Management's Discussion and Analysis (MD&A) the Company uses the terms "payout ratio", "field netback", "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 its statement of cash flows. Bonterra calculates cash and field 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

	2021		2020			
As at and for the periods ended ($ 000s except $ per share)	**Q2**	Q1	Q4	Q3	Q2	Q1
Financial						
Revenue - oil and gas sales	**59,163**	48,794	31,761	29,155	22,171	38,555
Cash flow from operations	**18,874**	14,745	(1,199)	6,370	4,429	22,473
Per share - basic	**0.56**	0.44	(0.04)	0.19	0.13	0.67
Per share - diluted	**0.55**	0.43	(0.04)	0.19	0.13	0.67
Net earnings (loss)[1]	**157,354**	(1,684)	(11,071)	(5,211)	(5,954)	(284,653)
Per share - basic	**4.68**	(0.05)	(0.33)	(0.16)	(0.18)	(8.53)
Per share - diluted	**4.55**	(0.05)	(0.33)	(0.16)	(0.18)	(8.53)
Capital expenditures	**7,607**	23,461	19,064	2,819	104	21,741
Total assets	**948,260**	748,543	731,859	722,910	732,462	743,533
Net debt	**319,310**	328,506	315,573	295,168	299,445	300,688
Shareholders' equity	**353,431**	195,393	196,633	207,325	212,342	218,211
Operations						
Light oil (barrels per day)	**7,370**	6,834	5,371	5,355	5,553	7,058
NGLs (barrels per day)	**996**	1,025	960	1,064	1,104	999
Conventional natural gas (MCF per day)	**26,057**	24,301	22,560	21,510	21,142	23,864
Total BOE per day	**12,709**	11,909	10,091	10,004	10,181	12,034

(1) In the first quarter of 2020 the Company recorded a $331,678,000 impairment provision less a $54,107,000 deferred income tax recovery related to its Alberta CGU's oil and gas assets due to the impact of COVID-19 on forward benchmark prices for crude oil. With stronger forward prices in Q2 2021, the Company recorded a $203,197,000 impairment reversal on its Alberta CGU's oil and gas assets less $47,149,000 deferred income tax expense.

	2019			
As at and for the periods ended ($ 000s except $ per share)	Q4	Q3	Q2	Q1
Financial				
Revenue - oil and gas sales	50,743	47,320	54,852	49,834
Cash flow from operations	20,767	19,774	25,468	15,123
Per share - basic and diluted	0.62	0.59	0.76	0.45
Net earnings (loss)	(1,389)	(1,276)	23,131	1,457
Per share - basic diluted	(0.04)	(0.04)	0.69	0.04
Capital expenditures	5,678	17,845	9,042	21,062
Total assets	1,087,817	1,133,137	1,123,513	1,124,043
Net debt	292,810	308,069	310,783	326,733
Shareholders' equity	503,949	506,011	507,659	484,980
Operations				
Light oil (barrels per day)	7,255	7,157	7,746	7,081
NGLs (barrels per day)	1,016	1,009	970	949
Conventional natural gas (MCF per day)	24,697	23,820	23,750	23,938
Total BOE per day	12,387	12,136	12,674	12,020

Business Environment and Sensitivities

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

	Q2-2021	Q1-2021	Q4-2020	Q3-2020	Q2-2020	Q1-2020	Q4-2019	Q3-2019
Crude oil								
WTI (U.S.$/bbl)	**66.07**	57.84	42.66	40.93	27.85	46.17	56.96	56.45
WTI to MSW Stream Index								
Differential (U.S.$/bbl)[1]	**(3.11)**	(5.24)	(4.07)	(3.51)	(6.14)	(7.58)	(5.37)	(4.66)
Foreign exchange								
U.S.$ to Cdn$	**1.2280**	1.2663	1.3031	1.3316	1.3860	1.3445	1.3201	1.3207
Bonterra average realized								
oil price (Cdn$/bbl)	**71.49**	61.76	47.16	45.73	33.31	49.67	63.37	65.49
Natural gas								
AECO (Cdn$/mcf)	**3.08**	3.14	2.63	2.23	1.98	2.02	2.46	0.91
Bonterra average realized								
gas price (Cdn$/mcf)	**3.37**	3.44	3.02	2.40	2.14	2.26	2.71	0.96

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

Bonterra's average realized commodity prices can be impacted by numerous events or factors. Most impactful has been the ongoing effects of the COVID-19 pandemic. Since the onset of COVID-19 in early 2020, volatility in WTI benchmark pricing has been significant. WTI benchmark prices for the second quarter of 2021 increased almost US$10 per barrel compared to the first quarter of 2021. The increase was driven by continuing improvements in real demand, coupled with ongoing supply discipline from both OPEC+ and US shale producers. These factors have led to significant destocking of global crude and product inventories, which has supported a higher price environment. It is still highly uncertain as to where supply and demand levels will be through the second half of 2021 and as such, it is likely that pricing volatility will continue through the remainder of 2021.

Canadian crude oil differentials tightened in the second quarter of 2021 compared to the previous quarter, as steady demand and production levels, adequate egress and storage level stability all contributed to the improvement in the differential. Currently, there are several pipeline projects underway, the most significant two being the Enbridge Line 3 Expansion and the Trans Mountain Expansion. Completion of any proposed pipeline expansion projects or increasing Canada's export capabilities by expanding capacity on existing lines is anticipated to have a positive effect on the movement and pricing of Canadian barrels. Renewed concerns around the fate of Enbridge's Line 5 crossing into Michigan is a factor that could have a negative effect on the pricing differential between WTI and MSW or Edmonton Par pricing.

The AECO benchmark price for natural gas dipped slightly in the second quarter of 2021 relative to the previous quarter. However, access to storage, limited maintenance on TC Energy Corporation's NGTL pipeline system and robust intra provincial demand compared to prior years have had a positive effect on pricing year to date in 2021. Forecast pricing though the remainder of 2021 continues to reflect an improved and stable AECO market. Planned facility additions for the NGTL system in the near term and progress by LNG Canada for the Kitimat liquefied natural gas export facility over the longer term may continue to improve market sentiment towards western Canadian-based natural gas producers.

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 2021[1]			
Impact on cash flow	Change ($)	$000s	$ per share[2]
Realized crude oil price ($/bbl)	1.00	2,509	0.07
Realized natural gas price ($/mcf)	0.10	910	0.03
U.S.$ to Canadian $ exchange rate	0.01	1,380	0.04

(1) This analysis uses current royalty rates, annualized estimated average production of 13,000 BOE per day and no changes in working capital.
(2) Based on annualized basic weighted average shares outstanding of 33,628,946.

Business Overview, Strategy and Key Performance Drivers

Oil prices have steadily risen as stability has returned to commodity markets to date in 2021. The Company fully funded its 2021 capital program to date with the support of the Business Development Bank of Canada's ("BDC") $45 million second lien non-revolving four-year term loan (the "BDC Term Loan"). As a result of the BDC Term Loan, Bonterra has been able to return to pre-COVID-19 production levels and take advantage of rising commodity prices to maximize cash flow. The Company averaged 12,311 BOE per day of production for the first six months of 2021, an increase of 1,203 BOE per day from the same period in 2020 and averaged 12,709 BOE per day through the second quarter. However, the emergence of new COVID-19 variants and differing progress between countries' vaccination programs has created demand uncertainty. Bonterra believes the Company has established a strong position to continue pursuing profitable development of its high-quality, light oil weighted asset base and can continue to act swiftly and prudently to strategically manage changes in the Company's financial position. Bonterra remains committed to preserving the value of its crude oil reserves should further events adversely impact crude oil prices.

The Company achieved many milestones during the first half of 2021, highlighted by a decline of approximately 35 percent in drilling, completion, and equipping costs per well through the first six months of 2021 compared to the same period a year ago. Bonterra invested a total of $31.0 million in the first six months of 2021 or approximately 48 percent of the lower end of its annual capital budget. Of the total capital invested, $24.6 million was directed to the drilling of 16 gross (15.9 net) wells and the completing, equipping, tying-in and placing on production of 20 gross (19.7 net) wells, with four of the completed and equipped wells having been drilled late in 2020. Included in the total capital program of $31.0 million was approximately $6.4 million that was directed to related infrastructure and recompletions. Since the majority of the production from new wells was brought online in March and April of 2021, the second quarter benefited from having nearly a full quarter of volume contribution.

Bonterra successfully abandoned 137.3 net wells during the first six months of 2021 with support from the Alberta Site Rehabilitation Program ("SRP"). As the Company continues to execute its abandonment program through the remainder of 2021 and 2022, a further 170.5 net wells that have no deemed future potential are forecast to be abandoned. Bonterra continuously reviews its inactive well inventory for future potential to determine if a well bore should be reactivated, repurposed, or abandoned.

On June 25, 2021, the Company's syndicated bank facility was redetermined at $265 million, a reduction from the $300 million previously in place. The bank facility is comprised of a $175 million syndicated revolving credit facility, a $25 million non-syndicated revolving credit facility and term debt of $65 million. The revolving period on the bank facility expires on December 31, 2021, with a maturity date of May 31, 2022. The available lending limit of the bank facility is scheduled to be reviewed before November 30, 2021. As at June 30, 2021, Bonterra had $244 million drawn on the $265 million bank facility. These credit facilities provide the Company with sufficient liquidity and financial flexibility. The Company's primary focus remains on reducing its bank debt by increasing production and cash flow on its low decline properties while continuing to add reserve value.

To further support stability while facing continued market volatility, and as part of Bonterra's ongoing efforts to diversify commodity pricing and to protect future cash flows, the Company has executed physical delivery sales and risk management contracts to the end of June 30, 2022. For the remainder of 2021, Bonterra had secured a WTI price between $36.00 USD to $50.50 USD per bbl on 2,250 bbls per day, with a WTI to Edmonton par differential average of $7.53 on 2,247 bbls per day. During the first six months of 2022, Bonterra has secured WTI price between $48.00 USD to $79.75 USD per bbl on 2,275 bbls per day, with a WTI to Edmonton par differential average of $6.34 on 1,502 bbls per day. In addition, the Company has secured a natural gas price between $2.00 to $3.10 on 7,275 GJ per day for the next twelve months, representing approximately 30 percent of Bonterra's expected crude oil and natural gas production.

Bonterra is committed to employing local services in Drayton Valley and to being a key economic contributor to rural and surrounding communities located within central Alberta. The Company's upstream oil and gas assets are primarily focused on the development of the Pembina and Willesden Green Cardium lands within central Alberta. The Pembina Cardium reservoir is the largest conventional oil reservoir in western Canada that features large original-oil-in-place with very low recoveries to date. Bonterra operates approximately 90 percent of its production and operates the majority of its related oil and gas processing facilities, which require minimal additional capital to support an increase in production.

Bonterra's successful operations are dependent upon several factors including, but not limited to: commodity prices, efficient management of capital spending, the 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 production 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						Six months ended			
		June 30, 2021		March 31, 2021		June 30, 2020		**June 30, 2021**		June 30, 2020
	Gross(1)	**Net(2)**	Gross(1)	Net(2)	Gross(1)	Net(2)	**Gross(1)**	**Net(2)**	Gross(1)	Net(2)
Crude oil horizontal-operated	**3**	**3.0**	13	12.9	-	-	**16**	**15.9**	8	8.0
Crude oil horizontal-non-operated	**-**	**-**	-	-	-	-	**-**	**-**	-	-
Total	**3**	**3.0**	13	12.9	0	0.0	**16**	**15.9**	8	8.0
Success rate		**100%**		100%		88%		**100%**		88%

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

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

During the first six months of 2021, the Company drilled 16 gross (15.9 net) operated wells and completed, tied-in and placed on production 20 gross (19.7 net) operated wells. Four of the wells that were completed and tied-in during Q1 2021 were drilled in late 2020. Approximately eight gross (6.9 net) operated wells are expected to be drilled and completed in Q3 2021.

Production

	Three months ended			Six months ended	
	June 30, 2021	March 31, 2021	June 30, 2020	**June 30, 2021**	June 30, 2020
Crude oil (barrels per day)	**7,370**	6,834	5,553	**7,103**	6,306
NGLs (barrels per day)	**996**	1,025	1,104	**1,011**	1,052
Natural gas (MCF per day)	**26,057**	24,301	21,142	**25,184**	22,503
Average BOE per day	**12,709**	11,909	10,181	**12,311**	11,108

The Company averaged 12,311 BOE per day of production in the first six months of 2021, compared to 11,108 BOE per day for the same period in 2020. The increase in production is largely due to the Company's drilling program re-commencing in the fourth quarter of 2020 along with the reactivation of down wells that were voluntarily shut-in due to low commodity prices from the onset of the COVID-19 pandemic. The Company's capital program was suspended from April 2020 until late in the fourth quarter of 2020, and with the support of the BDC Term Loan, Bonterra has exceeded Q1 2020 (pre COVID-19) production levels. As the average number of days on production from new wells was only 35 days in Q1 2021, Bonterra realized further production growth in Q2 2021 as the full benefit of the new wells was realized. The Company expects to be within its 2021 annual production guidance of 12,800 to 13,200 BOE per day.

Cash Netback

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

	Three months ended			Six months ended	
	June 30,	March 31,	June 30,	**June 30,**	June 30,
$ per BOE	**2021**	2021	2020	**2021**	2020
Production volumes (BOE)	**1,156,521**	1,071,835	926,516	**2,228,357**	2,021,650
Gross production revenue	**51.16**	45.52	23.93	**48.45**	30.04
Risk management contracts realized gain (loss)	**(3.38)**	(1.83)	0.95	**(2.64)**	1.22
Royalties	**(5.21)**	(3.53)	(1.64)	**(4.41)**	(2.11)
Production costs	**(14.98)**	(15.60)	(13.84)	**(15.28)**	(14.93)
Field netback	**27.59**	24.56	9.40	**26.12**	14.22
General and administrative	**(1.74)**	(2.68)	(1.64)	**(2.19)**	(1.59)
Interest and other	**(5.87)**	(6.40)	(3.24)	**(6.12)**	(3.30)
Cash netback	**19.98**	15.48	4.52	**17.81**	9.33

Cash netbacks in the first six months of 2021 compared to the same period in 2020 increased primarily due to higher realized oil prices. This was partially offset by increased royalties, interest costs and realized losses on risk management contracts. Quarter-over-quarter cash netbacks increased primarily due to further oil price recovery offset by an increase in royalties and risk management contract losses due to an increase in commodity prices. General and administrative costs in Q1 2021 were higher due to costs related to the unsolicited hostile bid which expired March 29, 2021.

Oil and Gas Sales

	Three months ended			Six months ended	
	June 30,	March 31,	June 30,	**June 30,**	June 30,
	2021	2021	2020	**2021**	2020
Revenue - oil and gas sales ($ 000s)					
Crude oil	**47,948**	37,986	16,835	**85,934**	48,740
NGL	**3,225**	3,285	1,220	**6,510**	2,967
Natural gas	**7,990**	7,523	4,116	**15,513**	9,019
	59,163	48,794	22,171	**107,957**	60,726
Average realized prices:					
Crude oil ($ per barrel)	**71.49**	61.76	33.31	**66.84**	42.47
NGLs ($ per barrel)	**35.59**	35.60	12.14	**35.59**	15.50
Natural gas ($ per MCF)	**3.37**	3.44	2.14	**3.40**	2.20
Average ($ per BOE)	**51.16**	45.52	23.93	**48.45**	30.04
Average BOE per day	**12,709**	11,909	10,181	**12,311**	11,108

Revenue from oil and gas sales in the first six months of 2021 increased by $47,231,000, or 78 percent, compared to the same period in 2020. This increase was primarily driven by a 57 percent increase in Bonterra's realized crude oil prices and a ten percent increase in production. Quarter-over-quarter, oil and gas sales increased as the Company benefited from a further oil price recovery while natural gas prices remained relatively constant due to warmer than average weather. Production increased by seven percent in Q2 2021 over Q1 2021 from the Company's drilling program.

Bonterra's product split on a revenue basis was weighted approximately 86 percent to crude oil and NGLs during the first half of 2021.

Royalties

	Three months ended			Six months ended	
	June 30,	March 31,	June 30,	**June 30,**	June 30,
($ 000s)	**2021**	2021	2020	**2021**	2020
Crown royalties	**3,470**	1,862	1,000	**5,332**	2,535
Freehold, gross overriding and other royalties	**2,560**	1,924	520	**4,484**	1,740
Total royalties	**6,030**	3,786	1,520	**9,816**	4,275
Crown royalties - percentage of revenue	**5.9**	3.8	4.5	**4.9**	4.2
Freehold, gross overriding and other royalties - percentage of revenue	**4.3**	3.9	2.3	**4.2**	2.9
Royalties - percentage of revenue	**10.2**	7.7	6.8	**9.1**	7.1
Royalties $ per BOE	**5.21**	3.53	1.64	**4.41**	2.11

Royalties paid by the Company consist of both Crown royalties to the Provinces of Alberta, Saskatchewan and British Columbia and other royalties. Total royalties for the six month period ended June 30, 2021 increased by $2.30 per BOE and quarter over quarter increased by $1.68 per BOE. The increase in both periods was primarily the result of an increase in crude oil prices.

Production Costs

	Three months ended			Six months ended	
	June 30,	March 31,	June 30,	**June 30,**	June 30,
($ 000s except $ per BOE)	**2021**	2021	2020	**2021**	2020
Production costs	**17,327**	16,716	12,823	**34,043**	30,187
$ per BOE	**14.98**	15.60	13.84	**15.28**	14.93

Production costs for the first half of 2021 increased from the same period in 2020 primarily due to increased maintenance costs with more well reactivations from the prior year, an increase in power costs from higher energy rates and an increase in Alberta government levies as some amounts were waived in 2020.

Production costs for Q2 2021 decreased from Q1 2021 on per BOE basis. The decrease was primarily due to increased volumes over fixed costs and the Company expanding its infrastructure. This was partially offset by the increased maintenance costs from spring break up and facility turnarounds.

Other Income

	Three months ended			Six months ended	
	June 30,	March 31,	June 30,	**June 30,**	June 30,
($ 000s)	**2021**	2021	2020	**2021**	2020
Investment income	**20**	5	8	**24**	19
Administrative income	**104**	63	42	**168**	86
Deferred consideration	**321**	286	132	**607**	474
Government grant in-kind	**1,339**	2,083	-	**3,422**	-
Realized gain (loss) on risk management contracts	**(3,910)**	(1,966)	877	**(5,876)**	2,465
Unrealized gain (loss) on risk management contracts	**(5,070)**	(4,850)	(2,950)	**(9,920)**	(1,154)
	(7,196)	(4,379)	(1,891)	**(11,575)**	1,890

Deferred consideration relates to a deferred gain on the sale of a two percent overriding royalty interest, which is recognized into revenue using the same unit-of-production method as the encumbered property, plant, and equipment assets.

The market value and carrying value of the investments held by the Company on June 30, 2021 was $563,000 (June 30, 2020 - $189,000). There were no dispositions for the period ended June 30, 2021 or June 30, 2020. 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 provided and production equipment rentals to other companies.

The Government of Alberta's SRP provides grant funding through service providers to abandon or remediate oil and gas sites. The Company derecognized approximately $3,422,000 of asset retirement obligations as an in-kind grant for the first six months of 2021 (June 30, 2020 - $nil). The benefit of the in-kind grant is recognized through other income.

To minimize commodity price risk on crude oil and natural gas sales, Bonterra has entered into financial derivatives. The financial derivatives outstanding are for the period from July 1, 2021 to June 30, 2022 and are for a total of 620,300 barrels of light crude oil (approximately 1,750 barrels of oil per day for the remainder of 2021, 2,000 barrels of oil per day for Q1 2022 and 1,300 barrels of oil per day for Q2 2022) at fixed WTI prices ranging from $36.00 USD to $79.75 USD per barrel, with a fixed differential from WTI to Edmonton Par prices for 484,300 barrels of oil (approximately 1,325 barrels of oil per day) at prices ranging from approximately $5.80 to $8.10 per barrel. Bonterra also fixed 1,800 GJ per day of natural gas for the remainder of 2021 at $2.24 per GJ. These contracts are not considered normal sales contracts and are recorded at fair value.

General and Administration ("G&A") Expense

	Three months ended			Six months ended	
	June 30,	March 31,	June 30,	**June 30,**	June 30,
($ 000s except $ per BOE)	**2021**	2021	2020	**2021**	2020
Employee compensation	**1,123**	999	700	**2,122**	1,841
Office and administrative - recurring	**888**	930	816	**1,818**	1,369
Total G&A recurring	**2,011**	1,929	1,516	**3,940**	3,210
Office and administrative - nonrecurring	**-**	946	-	**946**	-
Total G&A	**2,011**	2,875	1,516	**4,886**	3,210
$ per BOE recurring	**1.74**	1.80	1.64	**1.77**	1.59
$ per BOE nonrecurring	**-**	0.88	-	**0.42**	-
$ per BOE total	**1.74**	2.68	1.64	**2.19**	1.59

Employee compensation expense increased by $281,000 for the first six months of 2021 compared to 2020. In 2020, as a result of COVID-19, the Company cutback staffing costs and utilized the Canadian Emergency Wage Subsidy ("CEWS") government program. The Company did not receive any CEWS payments in Q2 2021.

Office and administrative recurring expenses for 2021 increased by $449,000 compared to the same period in 2020 primarily due to an increase in bank renewal fees, insurance and legal fees.

Non-recurring office and administrative costs are expenditures related to successfully defending an unsolicited hostile bid for the Company that expired March 29, 2021.

Finance Costs

	Three months ended			Six months ended	
	June 30,	March 31,	June 30,	**June 30,**	June 30,
($ 000s except $ per BOE)	**2021**	2021	2020	**2021**	2020
Interest on bank debt	**6,057**	6,219	2,862	**12,276**	6,310
Subordinated debt interest	**571**	437	-	**1,008**	-
Other interest	**276**	271	192	**547**	459
Interest expense	**6,904**	6,927	3,054	**13,831**	6,769
$ per BOE	**5.97**	6.46	3.30	**6.21**	3.35
Unwinding of the discounted value of decommissioning liabilities	**805**	774	775	**1,579**	1,554
Total finance costs	**7,709**	7,701	3,829	**15,410**	8,323

Interest on bank debt increased in 2021 compared to 2020 due to an increase in interest rates stemming from the negative effects of COVID-19 on the Company's net debt to earnings before income taxes and depletion and amortization (or "EBITDA" as defined by the Company's bank facility) ratio and a new interest rate grid for the term portion of the facility. Interest costs were partially offset by a $25,455,000 reduction in the average bank debt balance outstanding. 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.

Subordinated debt interest relates to the BDC second lien non-revolving four-year term loan. The Company drew $28 million in Q4 2020 and $17 million in Q1 2021. The loan bears interest at five percent in the first year. For more information about the subordinated debt, refer to Note 8 of the June 30, 2021 condensed financial statements.

Other interest relates primarily to amounts paid to a related party (see related party transactions for details) and a $7,603,000 subordinated promissory note from a private investor. For more information about the subordinated promissory note, refer to Note 6 of the June 30, 2021 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 $1,881,000.

Share-Option Compensation

	Three months ended			Six months ended	
	June 30,	March 31,	June 30,	**June 30,**	June 30,
($ 000s)	**2021**	2021	2020	**2021**	2020
Share-option compensation	**251**	293	41	**544**	97

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 directors, officers and employees.

Share-option compensation increased by $447,000 in the first six months of 2021 compared to 2020. The increase is primarily due to the 1,200,000 options issued in the fourth quarter of 2020 (which will be fully amortized in 2021).

Based on the outstanding options as of June 30, 2021, the Company has an unamortized expense of $633,000, of which $469,000 will be recorded for the remainder of 2021, and $164,000 thereafter. For more information about options issued and outstanding, refer to Note 10 of the June 30, 2021 condensed financial statements.

Depletion and Depreciation, Exploration and Evaluation ("E&E") and Impairment

($ 000s)	Three months ended **June 30, 2021**	 March 31, 2021	 June 30, 2020	Six months ended **June 30, 2021**	 June 30, 2020
Depletion and depreciation	**17,333**	15,312	8,327	**32,645**	31,382
Impairment of oil and gas assets	**(203,197)**	-	-	**(203,197)**	331,678

The provision for depletion and depreciation ("D&D") increased in 2021 compared to 2020 primarily due to increased capital spending and production volumes, which was partially offset by less capital to deplete and depreciate from an impairment provision recorded in 2020.

At March 31, 2020 the Company determined that the carrying value of the Company's Alberta cash generating unit ("CGU") exceeded its recoverable amount. A total impairment loss of $331,678,000 was recognized, with $234,302,000 recognized on the Company's property, plant and equipment ("PP&E"), $92,810,000 was applied to the Company's goodwill and an additional $4,566,000 was applied to the Company's E&E assets. The impairment loss was the result of the COVID-19 pandemic's effect on the forward commodity benchmark prices used in impairment testing at March 31, 2020.

On June 30, 2021, the Company performed an impairment test due to higher commodity prices and an increase in the Company's market capitalization since the impairment loss recognized as at March 31, 2020. A total impairment reversal of $203,197,000 was recognized on Bonterra's Alberta CGU PP&E. The impairment reversal was up to the original carrying value less associated D&D.

The impairment charge or reversal does not impact the Company's cash flow or the amount of credit available under our bank credit facilities. For more information about PP&E, refer to Note 4 of the June 30, 2021 condensed financial statements.

Taxes

The Company recorded a deferred income tax expense of $46,565,000 (2020 – $55,929,000 recovery). The increase in deferred income tax expense for 2021 was primarily due to the impairment reversal recorded at the end of the second quarter of 2021 compared to an impairment provision recorded in the first quarter of 2020.

For additional information regarding income taxes, see Note 9 of the June 30, 2021 condensed financial statements.

Net Earnings (Loss)

($ 000s except $ per share)	Three months ended **June 30, 2021**	 March 31, 2021	 June 30, 2020	Six months ended **June 30, 2021**	 June 30, 2020
Net earnings (loss)	**157,354**	(1,684)	(5,954)	**155,670**	(290,607)
$ per share - basic	**4.68**	(0.05)	(0.18)	**4.63**	(8.70)
$ per share - diluted	**4.55**	(0.05)	(0.18)	**4.53**	(8.70)

Net earnings for the first six months of 2021 increased by $446,277,000 compared to the same period in 2020. The increase in net earnings was primarily attributed to an impairment reversal recorded in Q2 2021, compared to an impairment provision taken in Q1 2020 due to a recovery of forward commodity benchmark prices since the COVID-19 pandemic in 2020. The impairment provision and reversal, was reduced by deferred income taxes. Net earnings also increased from higher oil and gas sales due to improved commodity prices and higher production volumes.

Other Comprehensive Income (loss)

Other comprehensive income for 2021 consists of an unrealized gain before tax on investments (including investment in a related party) of $269,000 relating to an increase in the investments' fair value (June 30, 2020 – unrealized loss of $98,000). 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			Six months ended	
	June 30,	March 31,	June 30,	**June 30,**	June 30,
($ 000s except $ per share)	**2021**	2021	2020	**2021**	2020
Cash flow from operations	**18,874**	14,745	4,429	**33,619**	26,902
$ per share - basic	**0.56**	0.44	0.13	**1.00**	0.81
$ per share - diluted	**0.55**	0.43	0.13	**0.98**	0.81

In the first six months of 2021, cash flow from operations increased by $6,717,000 compared to the same period in 2020. This was primarily due to an increase in oil and gas sales, which was partially offset by a decrease in non-cash working capital, an increase in realized risk management contract losses and an increase in finance costs.

Quarter-over-quarter, cash flow from operations increased due to an increase in oil and gas sales from higher commodity prices and production volumes.

Related Party Transactions

Bonterra holds 1,034,523 (December 31, 2020 – 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 June 30, 2021 of $424,000 (December 31, 2020 – $233,000). The Company provides marketing services for Pine Cliff. All services performed were charged at estimated fair value. As at June 30, 2021, the Company had an account receivable from Pine Cliff of $22,000 (December 31, 2020 – $62,000).

As at June 30, 2021, a loan to Bonterra provided by the Company's CEO, director and major shareholder totaled $12,707,000 (December 31, 2020 - $12,366,000). The loan bears interest at five and a half percent and has no set repayment terms. Security under the debenture is over all of the Company's assets and is subordinated to all claims in favour of the syndicate of senior lenders (including subordinated debt) providing credit facilities to the Company. Interest paid on this loan in the first six months of 2021 was $nil (June 30, 2020 - $224,000). Effective June 1, 2020, principal payments or interest cannot be settled for cash but may be settled by the issuance of common shares. No common shares have been issued to date. In the first six months of 2021 interest accrued on this loan and added to the loan's principal totaled $341,000 (June 30, 2020 - $30,000).

Liquidity and Capital Resources

Net Debt to Cash Flow from Operations

Bonterra continues to focus on monitoring overall debt while managing its cash flow and capital expenditures. The Company's net debt to twelve-month trailing cash flow ratio as of June 30, 2021 was 8.2 to 1 times (versus 9.8 to 1 times at December 31, 2020). The decreased net debt to cash flow ratio is the result of an increase in the Company's twelve-month trailing cash flow that is primarily due to the economic recovery since the effect of the COVID-19 pandemic on crude oil prices. Compared to the first six months of 2020, net debt at June 30, 2021 increased by $19,865,000 due to an expanded capital program supported by the BDC facility which is designed to allow the Company to achieve 2021 average annual production at or above pre-COVID-19 levels of approximately 12,800 to 13,000 BOE per day. The Company's primary focus remains on reducing its bank debt. Bonterra will continue to assess its capital expenditures compared to cash flow from operations on a quarterly basis.

Working Capital Deficiency and Net debt

($ 000s)	**June 30, 2021**	March 31, 2021	December 31, 2020	June 30, 2020
Working capital deficiency	**273,141**	282,908	**287,412**	299,445
Subordinated debt	**46,169**	45,598	**28,161**	-
Net Debt	**319,310**	328,506	**315,573**	299,445

Net debt is a combination of subordinated debt and working capital. As of June 30, 2021, the Company's bank facility has a maturity date of May 31, 2022 and is recorded as a current liability. Bonterra actively monitors its credit availability and working capital to ensure that it has sufficient available funds to meet its financial requirements as they come due. Any of these events present risks that could affect Bonterra's ability to fund ongoing operations. If required, Bonterra will also consider short-term or long-term financing alternatives in order to meet its future liabilities.

Net debt for June 30, 2021 increased by $19,865,000 compared to June 30, 2020 primarily due to utilizing the $45 million available on the BDC second lien non-revolving four-year term loan for the Company's capital program in the fourth quarter of 2020 and the first quarter of 2021, which is designed to return production to pre-COVID-19 levels. Increased net debt was also the result of decreased cash flow in Q2 and Q3 2020 due to the effects of the COVID-19 pandemic on crude oil prices. With stronger prices in 2021, the Company will continue to reduce net debt as shown in the second quarter of 2021 compared to Q1 2021. For additional information on subordinated debt, see Note 8 of the June 30, 2021 condensed financial statements.

Working capital is calculated as current assets less current liabilities. Included in the working capital deficiency as at June 30, 2021 is $20,310,000 of debt relating to the subordinated promissory note and the amount due to a related party plus $244,321,000 of bank debt. Effective June 1, 2020, the Company cannot make principal payments on the related party loan or the subordinated promissory note without bank approval. Interest has been either accrued in accounts payable and accrued liabilities or settled by issuance of common shares. In April 2021, the Company issued 81,079 common shares to settle $206,000 of accrued interest on the subordinated promissory note for the period of October 1, 2020 to March 31, 2021. On July 8, 2021, the Company issued 19,132 common shares to settle the $103,000 of accrued interest on the subordinated promissory note for Q2 2021. During each quarter, the Company manages net debt by monitoring capital spending relative to cash flow from operations.

Financial Risk Management

Bonterra is exposed to market risk to the extent that the demand for oil and gas produced by the Company exists within Canada. External factors beyond the Company's control may affect the marketability of oil and gas produced. Oil prices are affected by worldwide supply and demand fundamentals and access to market, while natural gas prices are affected by North American supply and demand fundamentals. In order to manage commodity risk, in 2021 the Company executed physical delivery sales contracts, which are considered normal sales contracts and are not recorded at fair value in the financial statements, and in addition executed risk management contracts which are not considered normal sales contracts and are recorded at fair value. The Company has contracts in place on approximately 30 percent of its estimated oil and gas production. The Company relies on its cash flow, access to equity markets and bank financing to support its operations and capital program. Bonterra uses these futures contracts to hedge its exposure to the potential adverse impact of commodity price volatility and provide a measure of stability to Bonterra's capital development program. For more information on physical delivery and risk management contracts in place see Note 12 of the June 30, 2021 condensed financial statements.

Capital Expenditures

During the six months ended June 30, 2021, the Company incurred capital expenditures of $31,068,000 (June 30, 2020 - $21,845,000). Of the total capital invested, $24,639,000 was directed to the drilling of 16 gross (15.9 net) wells and the completion, equip and tie-in of 20 gross (19.7 net) wells, of which four of the completed and equipped wells were drilled in 2020. All 16 wells drilled have been placed on production as of June 30, 2021. An additional $6,429,000 was spent primarily on related infrastructure and recompletions.

Decommissioning Liabilities

Bonterra has entered into the province of Alberta's Area-Based Closure ("ABC") program to reduce abandonment and reclamation costs and liabilities. This program provides numerous incentives to efficiently manage decommissioning liabilities that reduce overall cost. The ABC program currently requires the Company to spend an annual commitment of approximately $3.3 million on its inactive wells, pipelines and facilities excluding any Alberta SRP funding. Due to the impact of COVID-19 in 2020, the previous year requirement has been extended to the end of 2021. The Company intends to spend approximately $5.1 million for the 2021 fiscal year, of which the Company spent $2.5 million as of June 30, 2021.

Bank Debt

Bank debt represents the outstanding amounts drawn on the Company's bank facility. On June 25, 2021, the Company's credit facility was redetermined at $265,000,000 (December 31, 2020 - $300,000,000), comprised of a $175,000,000 syndicated revolving credit facility, a $25,000,000 non-syndicated revolving credit facility and a term loan of $65,000,000. The amount drawn under the total bank facility at June 30, 2021 was $244,321,000 (December 31, 2020 - $252,255,000). The amounts borrowed under the renewed bank facility bear interest at a floating rate based on the applicable Canadian prime rate or Banker's Acceptance rate, plus between 2.00 percent and 10.00 percent, depending on the type of borrowing and the Company's consolidated debt to EBITDA ratio. The terms of the total revolving bank facility provide that the loan facility is revolving to December 31, 2021, with a maturity date of May 31, 2022. The available lending limit of the bank facility is scheduled to be reviewed before November 30, 2021.

Under the current credit facility, the Company is restricted from making any payment of principal or interest on account of the subordinated debt, the related party amount and the subordinated promissory note or make dividend distributions. In addition, the Company is also limited to expenditures on an annual basis which cannot:

- exceed 110 percent or be less than 90 percent of the forecasted decommissioning expenditures settled;
- exceed 110 percent of forecasted capital expenditures, and;
- exceed 110 percent of the forecasted operating expenses.

The Company was within all forecasted expenditure limits for the period ended June 30, 2021.

As at June 30, 2021, Bonterra classified its bank debt as a current liability and had a working capital deficiency. The Company was in compliance with all financial covenants on its total bank facility as at June 30, 2021.

After examining the economic factors that are causing the liquidity risk facing the Company, the judgment applied to these factors, and the various initiatives that the Company has and will undertake to strengthen its financial position, the Company believes it will have sufficient liquidity to support its ongoing operations and meet its current financial obligations as they come due for at least the next twelve months. There can be no assurance that the next bank review will not result in a material reduction in the borrowing base, and that the necessary funds will be available to meet its obligations as they become due, subject to other alternative sources of financing.

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 7 of the June 30, 2021 unaudited 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 also 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, December 31, 2020	**33,511,316**	**765,415**
Shares issued for interest on subordinated promissory note	**81,079**	**206**
Issued pursuant to the Company's share option plan	**64,915**	**140**
Transfer from contributed surplus to share capital		**73**
Balance, June 30, 2021	**33,657,310**	**765,834**

The Company provides a stock option plan for its directors, officers and employees. Under the plan, the Company may grant options for up to 3,365,731 (December 31, 2020 – 3,351,131) 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 10 of the June 30, 2021 unaudited condensed financial statements.

Dividend Policy

For the six months ended June 30, 2021, the Company did not declare or pay any dividends (June 30, 2020 – $1,002,000) ($0.03 per share).

On March 10, 2020, the Company's Board of Directors elected to suspend its monthly dividend, commencing on April 1, 2020.

Quarterly Financial Information

	2021		2020			
For the periods ended ($ 000s except $ per share)	**Q2**	Q1	Q4	Q3	Q2	Q1
Revenue - oil and gas sales	**59,163**	48,794	31,761	29,155	22,171	38,555
Cash flow from operations	**18,874**	14,745	(1,199)	6,370	4,429	22,473
Net earnings (loss)	**157,354**	(1,684)	(11,071)	(5,211)	(5,954)	(284,653)
Per share - basic	**4.68**	(0.05)	(0.33)	(0.16)	(0.18)	(8.53)
Per share - diluted	**4.55**	(0.05)	(0.33)	(0.16)	(0.18)	(8.53)

	2019			
For the periods ended ($ 000s except $ per share)	Q4	Q3	Q2	Q1
Revenue - oil and gas sales	50,743	47,320	54,852	49,834
Cash flow from operations	20,767	19,774	25,468	15,123
Net earnings (loss)	(1,389)	(1,276)	23,131	1,457
Per share - basic	(0.04)	(0.04)	0.69	0.04
Per share - diluted	(0.04)	(0.04)	0.69	0.04

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 2020, the Company's net earnings significantly decreased mainly due to the effect of the COVID-19 pandemic on crude oil demand. Cash flow from operations also decreased in the second quarter of 2020 due to low commodity prices at the peak of COVID-19's effect on oil prices. Although prices increased since the second quarter of 2020, the Company incurred $3,764,000 of costs related to an unsolicited hostile bid and an increase in bank finance costs which negatively impacted cash flow. With the utilization of the BDC funding on the Company's capital program and well reactivation costs in the fourth quarter of 2020, the Company expects higher production and cash flow from operations in the quarters subsequent to December 31, 2020. Net loss for Q1 2020 and net earnings in Q2 2021 is significantly higher than other quarters due to an impairment provision and reversal on the Company's Alberta cash generating unit.

Contractual Obligations and Commitments

At June 30, 2021, Bonterra's total contractual obligations and commitments were $335,113,000. These include obligations and commitments in place as of December 31, 2020, plus a draw of additional debt under the subordinated debt and accrued interest in the period, as well as additional firm service commitments entered into during the six months ended June 30, 2021. For more information, refer to Note 13 "Commitments and Financial Liabilities" of the June 30, 2021 condensed financial statements.

Off-Balance Sheet Financing

Bonterra does not have any guarantees or off-balance sheet arrangements that have been excluded from the condensed statement of financial position or balance sheet other than commitments disclosed in Note 13 of the June 30, 2021 condensed financial statements.

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.

Assessment of Business Risk

Bonterra's exploration and production activities are concentrated in the Western Canadian Sedimentary Basin, where activity is highly competitive and includes a variety of different sized companies. Bonterra is subject to a number of risks that are also common to other organizations involved in the oil and gas industry. Such risks include finding and developing oil and gas reserves at economic costs, estimating amounts of recoverable reserves, production of oil and gas in commercial quantities, marketability of oil and gas produced, fluctuations in commodity prices, stock market volatility, debt service which may limit market price of shares, financial and liquidity risks and environmental and safety risks.

The Company mitigates its risk related to producing hydrocarbons through the utilization of current technology and information systems. In addition, Bonterra strives to operate the majority of its properties, thereby maintaining operational control where possible.

The Company's business, operations and financial condition has been significantly adversely affected by COVID-19. Actions taken to reduce the spread of COVID-19 have resulted in volatility and disruptions in regular business operations, supply chains and financial markets. COVID-19 also poses a risk on the financial capacity of Bonterra's contract counterparties and potentially their ability to perform contractual obligations. These difficulties have been exacerbated in Canada by political and other actions resulting in uncertainty surrounding regulatory, tax, royalty changes and environmental regulation.

Additional information regarding risk factors including, but not limited to, business risks is available in our Annual Information Form for the year ended December 31, 2020, which can be accessed on our website www.bonterraenergy.com or on SEDAR at www.sedar.com.

Environmental Risk

General Risks

Oil and gas exploration and production can involve environmental risks such as litigation, physical and regulatory risks. Physical risks include the pollution of the environment, climate change and destruction of natural habitat, as well as safety risks such as personal injury. The Company conducts its operations and ensures to protect the environment, its various stakeholders, and the general public. Bonterra maintains current insurance coverage for comprehensive and general liability as well as limited pollution liability. The amount and terms of this insurance are reviewed on an ongoing basis and adjusted as necessary to reflect current corporate requirements, availability, as well as industry standards and government regulations. Without such insurance, and if the Company becomes subject to environmental liabilities, the payment of such liabilities could reduce or eliminate its available funds or could exceed the funds the Company has available and result in financial distress.

Climate Change Risks

Our exploration and production facilities and other operations and activities emit greenhouse gasses ("GHG") which may require us to comply with federal and/or provincial GHG emissions legislation. Climate change policy is evolving at regional, national and international levels, and political and economic events may significantly affect the scope and timing of climate change measures that are ultimately put in place to prevent climate change or mitigate our effects. The direct or indirect costs of compliance with GHG-related regulations may have a material adverse effect on our business, financial condition, results of operations and prospects. Some of our significant facilities may ultimately be subject to future regional, provincial and/or federal climate change regulations to manage GHG emissions. In addition, climate change has been linked to long-term shifts in climate patterns and extreme weather conditions both of which pose the risk of causing operational difficulties.

Additional information regarding risk factors including, but not limited to, environmental risks is available in our Annual Information Form for the year ended December 31, 2020, which can be accessed on our website www.bonterraenergy.com or on SEDAR at www.sedar.com.

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; climate change 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 or maintain its syndicated bank facility; 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 June 30, 2021 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 six months ended June 30, 2021.

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

MANAGEMENT'S RESPONSIBILITY FOR FINANCIAL STATEMENTS

The information provided in this report, including the financial statements, is the responsibility of management. The timely preparation of the financial statements requires that management make estimates and use judgment regarding the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities as at the date of the financial statements and the reported amounts of revenues and expenses during the period. Such estimates primarily relate to unsettled transactions and events as at the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur. Management believes such estimates have been based on careful judgments and have been properly reflected in the accompanying financial statements.

Management maintains a system of internal controls to provide reasonable assurance that the Company's assets are safeguarded and to facilitate the preparation of relevant and timely information.

The audit committee has reviewed these condensed financial statements with management and has reported to the Board of Directors. The Board of Directors has approved the financial statements as presented in this interim report.

CONDENSED STATEMENT OF FINANCIAL POSITION

As at (unaudited) ($ 000s)	Note	June 30, 2021	December 31, 2020
Assets			
Current			
Accounts receivable		**22,946**	12,891
Crude oil inventory		**653**	598
Prepaid expenses		**5,084**	3,920
Investments		**139**	62
		28,822	17,471
Investment in related party		**424**	233
Exploration and evaluation assets		**1,828**	373
Property, plant and equipment	4	**908,325**	704,921
Investment tax credit receivable	9	**8,861**	8,861
		948,260	731,859
Liabilities			
Current			
Accounts payable and accrued liabilities		**22,658**	28,229
Risk management contract	12	**13,519**	3,599
Due to related party	5	**12,707**	12,366
Subordinated promissory note	6	**7,603**	7,604
Bank debt	7	**244,321**	252,255
Deferred consideration		**1,155**	830
		301,963	304,883
Subordinated debt	8	**46,169**	28,161
Deferred consideration		**10,778**	11,709
Decommissioning liabilities		**135,852**	137,002
Deferred tax liability		**100,067**	53,471
		594,829	535,226
Shareholders' equity			
Share capital	10	**765,834**	765,415
Contributed surplus		**31,143**	30,672
Accumulated other comprehensive loss		**(512)**	(750)
Deficit		**(443,034)**	(598,704)
		353,431	196,633
		948,260	731,859

Commitments and contingencies	13
Subsequent events	6, 12

See accompanying notes to these condensed financial statements.

CONDENSED STATEMENT OF COMPREHENSIVE INCOME

For the periods ended June 30 (unaudited)		Three months ended		Six months ended	
($ 000s, except $ per share)	Note	**2021**	2020	**2021**	2020
Revenue					
Oil and gas sales, net of royalties	11	**53,133**	20,651	**98,141**	56,451
Other income	14	**1,463**	50	**3,614**	105
Deferred consideration		**321**	132	**607**	474
Gain (Loss) on risk management contracts		**(8,980)**	(2,073)	**(15,796)**	1,311
		45,937	18,760	**86,566**	58,341
Expenses					
Production		**17,327**	12,823	**34,043**	30,187
Office and administration		**888**	816	**2,764**	1,369
Employee compensation		**1,123**	700	**2,122**	1,841
Finance costs		**7,709**	3,829	**15,410**	8,323
Share-option compensation		**251**	41	**544**	97
Depletion and depreciation	4	**17,333**	8,327	**32,645**	31,382
Impairment (reversal of impairment)	4	**(203,197)**	-	**(203,197)**	331,678
		(158,566)	26,536	**(115,669)**	404,877
Earnings (loss) before income taxes		**204,503**	(7,776)	**202,235**	(346,536)
Taxes					
Deferred income tax expense (recovery)	9	**47,149**	(1,822)	**46,565**	(55,929)
		47,149	(1,822)	**46,565**	(55,929)
Net earnings (loss) for the period		**157,354**	(5,954)	**155,670**	(290,607)
Other comprehensive income (loss)					
Unrealized gain (loss) on investments		**179**	61	**269**	(98)
Deferred taxes on unrealized loss (gain) on investments		**(21)**	(17)	**(31)**	3
Other comprehensive income (loss) for the period		**158**	44	**238**	(95)
Total comprehensive income (loss) for the period		**157,512**	(5,910)	**155,908**	(290,702)
Net earnings (loss) per share - basic	10	**4.68**	(0.18)	**4.63**	(8.70)
Net earnings (loss) per share - diluted	10	**4.55**	(0.18)	**4.53**	(8.70)
Comprehensive income (loss) per share - basic	10	**4.69**	(0.18)	**4.64**	(8.71)
Comprehensive income (loss) per share - diluted	10	**4.56**	(0.18)	**4.54**	(8.70)

See accompanying notes to these condensed financial statements.

CONDENSED STATEMENT OF CASH FLOW

For the periods ended June 30 (unaudited)		Three months		Six months	
($ 000s)	Note	**2021**	2020	**2021**	2020
Operating activities					
Net earnings (loss)		**157,354**	(5,954)	**155,670**	(290,607)
Items not affecting cash					
Deferred income taxes expense (recovery)		**47,149**	(1,822)	**46,565**	(55,929)
Deferred consideration		**(321)**	(132)	**(607)**	(474)
Share-option compensation		**251**	41	**544**	97
Unrealized loss on risk management contracts	12	**5,070**	2,950	**9,920**	1,154
Depletion and depreciation		**17,333**	8,327	**32,645**	31,382
Government grant in-kind	14	**(1,339)**	-	**(3,422)**	-
Impairment (reversal of impairment)		**(203,197)**	-	**(203,197)**	331,678
Unwinding of the discount on decommissioning liabilities		**805**	775	**1,579**	1,554
Investment income		**(18)**	(8)	**(24)**	(19)
Interest expense		**6,904**	3,054	**13,831**	6,769
Change in non-cash working capital accounts:					
Accounts receivable		**(1,269)**	1,111	**(9,943)**	11,355
Crude oil inventory		**33**	172	**(57)**	60
Prepaid expenses		**(1,011)**	(681)	**(1,164)**	(79)
Accounts payable and accrued liabilities		**(1,333)**	(284)	**6,098**	(1,742)
Decommissioning expenditures		**(1,480)**	(130)	**(2,542)**	(1,592)
Interest paid		**(6,057)**	(2,990)	**(12,277)**	(6,705)
Cash provided by operating activities		**18,874**	4,429	**33,619**	26,902
Financing activities					
Increase (decrease) of bank debt		**5,456**	16,904	**(7,934)**	4,758
Subordinated debt		**-**	-	**17,000**	-
Stock option proceeds		**69**	-	**140**	-
Dividends		**-**	-	**-**	(1,002)
Cash provided by financing activities		**5,525**	16,904	**9,206**	3,756
Investing activities					
Investment income received		**18**	8	**24**	19
Exploration and evaluation expenditures		**(1,184)**	-	**(1,455)**	(586)
Property, plant and equipment expenditures	4	**(6,423)**	(104)	**(29,613)**	(21,259)
Change in non-cash working capital accounts:					
Accounts payable and accrued liabilities		**(16,667)**	(21,230)	**(11,669)**	(8,902)
Accounts receivable		**(143)**	(7)	**(112)**	70
Cash used in investing activities		**(24,399)**	(21,333)	**(42,825)**	(30,658)
Net change in cash in the period		**-**	-	**-**	-
Cash, beginning of period		**-**	-	**-**	-
Cash, end of period		**-**	-	**-**	-

See accompanying notes to these condensed financial statements.

CONDENSED STATEMENT OF CHANGES IN EQUITY

For the periods ended (unaudited)

($ 000's, except number of shares outstanding)

	Numbers of common shares outstanding (Note 10)	Share Capital (Note 10)	Contributed surplus [1]	Accumulated other Comprehensive loss [2]	Deficit	Total shareholders' equity
January 1, 2020	33,388,796	765,276	30,234	(748)	(290,813)	503,949
Share-option compensation			97			97
Comprehensive loss				(95)	(290,607)	(290,702)
Dividends					(1,002)	(1,002)
June 30, 2020	33,388,796	765,276	30,331	(843)	(582,422)	212,342
Share-option compensation			341			341
Shares issued for subordinated promissory note interest	122,520	139				139
Comprehensive income (loss)				93	(16,282)	(16,189)
December 31, 2020	33,511,316	765,415	30,672	(750)	(598,704)	196,633
Share-option compensation			544			544
Shares issued for subordinated promissory note interest	81,079	206				206
Exercise of options	64,915	140				140
Transfer to share capital on exercise of options		73	(73)			-
Comprehensive income				238	155,670	155,908
June 30, 2021	33,657,310	765,834	31,143	(512)	(443,034)	353,431

(1) All amounts reported in Contributed Surplus relate to share-option compensation.

(2) Accumulated other comprehensive income is comprised of unrealized gains and losses on investments fair value through other comprehensive income.

See accompanying notes to these condensed financial statements.

NOTES TO THE CONDENSED FINANCIAL STATEMENTS

As at June 30, 2021 and December 31, 2020 and for the six months ended June 30, 2021 and June 30, 2020. (unaudited)

1. NATURE OF BUSINESS AND SEGMENT INFORMATION

Bonterra Energy Corp. ("Bonterra" or the "Company") is a public company listed on the Toronto Stock Exchange (the "TSX") and incorporated under the Business Corporations Act (Alberta). The address of the Company's registered office is Suite 901, 1015-4th Street SW, Calgary, Alberta, Canada, T2R 1J4.

Bonterra operates in one industry and has only one reportable segment which is the development and production of oil and natural gas in the Western Canadian Sedimentary Basin.

The financial statements were authorized for issue by the Company's Board of Directors on August 11, 2021.

2. BASIS OF PREPARATION AND FUTURE OPERATIONS

a) Statement of Compliance

The Company prepares its unaudited condensed financial statements in accordance with International Accounting Standard 34 – Interim Financial Reporting (IAS 34).

The accounting policies and method of computation followed in the preparation of the condensed financial statements are the same as those followed in the preparation of Bonterra's 2020 audited annual financial statements, except as denoted below. These condensed financial statements do not include all of the information required for annual financial statements and should be read in conjunction with the 2020 audited annual financial statements, which have been prepared in accordance with International Financial Reporting Standards (IFRS).

3. NOVEL CORONAVIRUS COVID-19 ("COVID-19")

During the first quarter of 2020, the World Health Organization declared the novel coronavirus (COVID-19) outbreak a global pandemic prompting many countries around the world to close international borders, place restrictions on travel and force closures for certain types of public places and businesses that were deemed non-essential, causing significant disruption to global economies. Crude oil prices have partially recovered from the historic lows observed early in 2020, but price support from future demand remains uncertain. Efforts to re-open local economies and international borders around the globe resulted in varying degrees of virus outbreak and some countries have re-imposed restrictions with COVID-19 variants. Vaccinations programs continue to be administered around the world, however the pace with which vaccines are administered is dependent on the supply access and logistics organized by individual nations. The potential direct and indirect impacts of the economic downturn, including reduced demand for commodities and continued economic uncertainty, have been considered in management's estimates, and assumptions at period end.

4. PROPERTY, PLANT AND EQUIPMENT

Cost ($ 000s)	Oil and gas properties	Production facilities	Furniture fixtures & other equipment	Total property plant & equipment
Balance at December 31, 2020	1,457,565	369,585	2,297	1,829,447
Additions	20,652	8,947	14	29,613
Adjustment to decommissioning liabilities	3,235	-	-	3,235
Balance at June 30, 2021	**1,481,452**	**378,532**	**2,311**	**1,862,295**

Accumulated depletion and depreciation ($ 000s)	Oil and gas properties	Production facilities	Furniture fixtures & other equipment	Total property plant & equipment
Balance at December 31, 2020	(910,638)	(212,032)	(1,856)	(1,124,526)
Depletion and depreciation	(27,615)	(5,001)	(29)	(32,645)
Disposal and other	4	-	-	4
Impairment reversal	159,672	43,525	-	203,197
Balance at June 30, 2021	**(778,577)**	**(173,508)**	**(1,885)**	**(953,970)**

Carrying amounts as at: ($ 000s)				
December 31, 2020	546,927	157,553	441	704,921
June 30, 2021	**702,875**	**205,024**	**426**	**908,325**

Impairment

At June 30, 2021 the Company identified indicators of an impairment reversal due to increased forward commodity prices and an increase in the Company's market capitalization since the impairment loss recognized as at March 31, 2020. As a result, recovery testing was performed by preparing estimates of future cash flows to determine the recoverable amount of the respective assets.

At June 30, 2021 the Company determined that the recoverable amount of the Company's Alberta CGU exceeded its carrying value. A total impairment recovery of $203,197,000 was recognized in the Company's PP&E.

Impairment can be reversed for PP&E up to the lower of the recoverable amount or the original carrying value less any associated depletion and depreciation that would have been incurred had the impairment not occurred. Goodwill impairment cannot be reversed.

The following table outlines the forecasted benchmark commodity prices and the exchange rates used in the impairment (reversal) calculation of Property, plant and equipment ("PP&E") at June 30, 2021.

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031[2]
WTI Crude oil $US/Bbl [1]	71.33	67.20	63.95	63.23	64.50	65.79	67.10	68.44	69.81	71.21	72.63
AECO C-Spot $Mmbtu [1]	3.28	2.97	2.58	2.57	2.62	2.67	2.73	2.78	2.84	2.90	2.95
Exchange rate US$/$Cdn	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80	0.80

(1) The forecast benchmark commodity prices listed above are adjusted for quality differentials, heat content, transportation and marketing costs and other factors specific to the Company's operations in performing the Company's impairment tests.

(2) Forecast benchmarks commodity prices are assumed to increase by 2.0% in each year after 2030 to end of the reserve life.

Discount rate - The Company used a pre-tax discount rate of 15 percent that reflects risks specific to the assets for which the future cash flow estimates have not been adjusted. The discount rate was determined based on the Company's assessment of risk based on experience. Changes in the general economic environment could result in material changes to this estimate.

Changes in any of the key judgments, such as a revision in reserves, changes in forecast benchmark commodity prices, discount rates, foreign exchange rates, capital or operating costs would impact the recoverable amounts of assets and any recoveries or impairment changes would affect net earnings. The most sensitive assumptions to the calculation are the discount rate and forecast benchmark commodity price estimates at June 30, 2021. The Company concluded that no reasonable change in the key assumptions, such as a two percent change in commodity prices or a one percent change in the discount rate, would result in a different impairment reversal being recorded.

5. TRANSACTIONS WITH RELATED PARTIES

As at June 30, 2021, a loan to Bonterra provided by the Company's CEO, director and major shareholder totaled $12,707,000 (December 31, 2020 - $12,366,000). The loan bears interest at five and a half percent and has no set repayment terms. Effective June 1, 2020, principal or interest payments cannot be settled for cash but may be settled by the issuance of common shares. No common shares have been issued to date. Security under the debenture is over all of the Company's assets and is subordinated to all claims in favour of the syndicate of senior lenders (including subordinated debt) providing credit facilities to the Company. Interest paid on this loan in the first six months of 2021 was $nil (June 30, 2020 - $224,000). In the first six months of 2021 interest accrued on this loan and added to the loan's principal totaled $341,000 (June 30, 2020 - $30,000).

The Company provides executive and marketing services for Pine Cliff Energy Ltd. (Pine Cliff). All services performed were charged at estimated fair value. As at June 30, 2021, the Company had an account receivable from Pine Cliff of $22,000 (December 31, 2020 – $62,000).

6. SUBORDINATED PROMISSORY NOTE

As at June 30, 2021, Bonterra had $7,603,000 (December 31, 2020 - $7,604,000) outstanding on a subordinated promissory note to a private investor. The note bears interest at five and a half percent. Effective June 1, 2020, principal or interest payments cannot be settled for cash but may be settled by the issuance of common shares. Security consists of a floating demand debenture over all of the Company's assets and is subordinated to all claims in favor of the syndicate of senior lenders (including subordinated debt) providing credit facilities to the Company. Interest settled in cash on the subordinated promissory note for the six months ended June 30, 2021 was $nil (June 30, 2020 - $171,000). In April 2021, the Company issued 81,079 common shares to settle $206,000 of accrued interest for the period October 1, 2020 to March 31, 2021. On July 8, 2021, the Company issued 19,132 common shares to settle the $103,000 of accrued interest for the three months ended June 30, 2021.

7. BANK DEBT

As at June 30, 2021, the Company has a total bank facility of $265,000,000 (December 31, 2020 - $300,000,000), comprised of a $175,000,000 syndicated revolving credit facility, a $25,000,000 non-syndicated revolving credit facility and a term loan of $65,000,000. The amount drawn under the total bank facility at June 30, 2021 was $244,321,000 (December 31, 2020 - $252,255,000). The amounts borrowed under the renewed bank facility bear interest at a floating rate based on the applicable Canadian prime rate or Banker's Acceptance rate, plus between 2.00 percent and 10.00 percent, depending on the type of borrowing and the Company's consolidated debt to EBITDA ratio. EBITDA is defined as net income for the period 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. The terms of the total revolving bank facility provide that the loan facility is revolving to December 31, 2021, with a maturity date of May 31, 2022. The available lending limit of the bank facility is scheduled to be reviewed before November 30, 2021.

The amount available for borrowing under the bank facility is reduced by outstanding letters of credit. Letters of credit totaling $1,245,000 were issued as at June 30, 2021 (December 31, 2020 - $1,245,000). Security for the bank facility consists of various floating demand debentures totaling $750,000,000 (December 31, 2020 - $750,000,000) over all of the Company's assets and a general security agreement with first ranking over all personal and real property.

Under the credit facility, the Company is restricted from making any payment of principal or interest on account of subordinated promissory note and due to related party debt or dividend distributions. In addition, the Company is also limited to expenditures on an annual basis which cannot:

- exceed 110 percent or be less than 90 percent of the forecasted decommissioning expenditures settled;
- exceed 110 percent of forecasted capital expenditures; and
- exceed 110 percent of the forecasted operating expenses.

As at June 30, 2021, Bonterra was in compliance with all financial covenants on its total bank facility.

8. SUBORDINATED DEBT

Effective November 13, 2020, the Company entered into a second lien non-revolving four-year term facility from Business Development Bank of Canada (the "BDC") for $45,000,000, through the Business Credit Availability Program (the "BCAP"). The amount drawn under the BCAP facility at June 30, 2021 was $45,000,000 (December 31, 2020 - $28,000,000). Interest owing under the BCAP facility is accrued and added to the principal at five percent for the first year from the effective date. Thereafter interest (including accrued interest) will be paid monthly at an interest rate calculated as the greater of the revolving bank facility rate plus 1.00 percent or a fixed interest rate of 6.00 percent, increasing by 1.00 percent in each of the subsequent years. Security consists of a floating demand debenture over all of the Company's assets and is subordinated to all claims in favor of the syndicate of senior lenders providing credit facilities to the Company. Interest accrued and capitalized on the BCAP facility during the first six months of 2021 was $1,008,000 (June 30, 2020 - $nil).

9. INCOME TAXES

($ 000s)	**June 30, 2021**	December 31, 2020
Deferred tax asset (liability) related to:		
Investments	**49**	80
Exploration and evaluation assets and property, plant and equipment	**(155,195)**	(100,243)
Investment tax credits	**(2,041)**	(2,041)
Decommissioning liabilities	**31,287**	31,558
Corporate tax losses carried forward	**26,867**	20,496
Financial derivative	**3,114**	829
Corporate capital tax losses carried forward	**7,453**	7,488
Unrecorded benefits of capital tax losses carried forward	**(7,453)**	(7,488)
Unrecorded benefits of successored resource related pools	**(4,148)**	(4,150)
Deferred tax asset (liability)	**(100,067)**	(53,471)

Income tax expense varies from the amounts that would be computed by applying Canadian federal and provincial income tax rates as follows:

	Three Months		Six Months	
($ 000s)	**June 30, 2021**	June 30, 2020	**June 30, 2021**	June 30, 2020
Earnings (loss) before taxes	**204,503**	(7,776)	**202,235**	(346,536)
Combined federal and provincial income tax rates	**23.03%**	25.02%	**23.03%**	25.02%
Income tax provision calculated using statutory tax rates	**47,095**	(1,946)	**46,575**	(86,691)
Increase (decrease) in taxes resulting from:				
Share-option compensation	**59**	11	**125**	24
Impairment of goodwill	**-**	-	**-**	23,218
Change in unrecorded benefits of tax pools	**(37)**	(3)	**(37)**	2,525
Change in estimates and other	**32**	116	**(98)**	4,995
	47,149	(1,822)	**46,565**	(55,929)

(1) Effective July 1, 2020 the combined federal and provincial tax rate for Bonterra is approximately 23.00% due to the provincial tax rate for Alberta, Canada decreasing from 10% to 8%.

The Company has the following tax pools, which may be used to reduce taxable income in future years, limited to the applicable rates of utilization:

($ 000s)	Rate of Utilization (%)	Amount
Undepreciated capital costs	7-100	53,148
Canadian oil and gas property expenditures	10	71,746
Canadian development expenditures	30	88,664
Canadian exploration expenditures	100	9,111
Federal income tax losses carried forward[1]	100	129,784
Provincial income tax losses carried forward[2]	100	91,724
		444,177

[1] Federal income tax losses carried forward expire in the following years: 2035 - $8,156,000; 2036 - $35,823,000; 2037 - $182,000; 2039- $2,163,000; 2040 - $55,757,000; 2041 - $27,703,000.

[2] Provincial income tax losses carried forward expire in the following years: 2036 - $5,562,000; 2037 - $182,000; 2039 - $2,520,000; 2040 - $55,757,000; 2041-$27,703,000.

The Company has $8,861,000 (December 31, 2020 - $8,861,000) of investment tax credits that expire in the following years: 2024 - $1,319,000; 2025 - $2,258,000; 2026 - $2,405,000; 2027- $2,009,000; 2028 - $745,000; 2034 - $99,000; and 2037 - $26,000.

The Company has $64,725,000 (December 31, 2020 - $65,015,000) of capital losses carried forward which can only be claimed against taxable capital gains.

10. SHAREHOLDERS' EQUITY

Authorized

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

Issued and fully paid - common shares	**Number**	**Amount ($ 000s)**
Balance, December 31, 2020	**33,511,316**	**765,415**
Shares issued for interest on subordinated promissory note	**81,079**	**206**
Issued pursuant to the Company's share option plan	**64,915**	**140**
Transfer from contributed surplus to share capital		**73**
Balance, June 30, 2021	**33,657,310**	**765,834**

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.

The weighted average common shares used to calculate basic and diluted net earnings per share for the three and six months ended June 30, 2021, are as follows:

	Three Months		Six Months	
	2021	2020	**2021**	2020
Basic shares outstanding	**33,618,311**	33,388,796	**33,612,575**	33,388,796
Dilutive effect of share options[1]	**958,585**	-	**744,236**	9,416
Diluted shares outstanding	**34,576,896**	33,388,796	**34,356,811**	33,398,212

[1] The Company did not include 75,400 share-options for the three months ended June 30, 2021 (June 30, 2020 - 2,752,700) and 32,900 share-options for the six months ended June 30, 2021 (June 30, 2020 – 2,572,700) in the dilutive effect of share-options calculations as these share-options were anti-dilutive.

For the six months period ended June 30, 2021, the Company did not declare or pay dividends (June 30, 2020 - $1,002,000 ($0.03 per share)). The dividend was suspended effective April 1, 2020.

The Company provides an equity settled option plan for its directors, officers and employees. Under the plan, the Company may grant options for up to 3,365,731 (December 31, 2020 – 3,351,131 common shares). The exercise price of each option granted cannot be lower than the market price of the common shares on the date of grant and the option's maximum term is five years.

A summary of the status of the Company's stock options as of June 30, 2021 and changes during the year are presented below:

	Number of options	**Weighted average exercise price**
At December 31, 2020	2,426,700	$2.63
Options granted	145,500	4.04
Options exercised[1]	(115,600)	3.14
Options forfeited	(87,000)	1.96
Options expired	(37,000)	12.00
At June 30, 2021	2,332,600	$2.57

(1) 71,000 options were exercised under the cashless option method, which resulted in 20,315 shares being issued in which the Company received no proceeds.

The following table summarizes information about options outstanding and exercisable as at June 30, 2021:

	Options outstanding				Options exercisable		
Range of exercise prices	Number outstanding	Weighted-average remaining contractual life		Weighted-average exercise price	Number exercisable		Weighted-average exercise price
$ 1.00 - $ 5.00	2,227,600	1.5 years	$	2.28	404,250	$	2.85
5.01 - 10.00	81,000	1.5 years		5.78	33,000		5.84
10.01 - 20.00	24,000	0.7 years		18.40	14,000		17.76
$ 1.00 - $ 20.00	2,332,600	1.5 years	$	2.57	451,250	$	3.53

The Company records compensation expense over the vesting period, which ranges between one and three years, based on the fair value of options granted to directors, officers and employees. In 2021, the Company granted 145,500 options with an estimated fair value of $239,000 or $1.64 per option using the Black-Scholes option pricing model with the following key assumptions:

	June 30, 2021
Weighted-average risk free interest rate (%)[1]	**0.36**
Weighted-average expected life (years)	**2.0**
Weighted-average volatility (%)[2]	**86.32**
Forfeiture rate (%)	**7.65**
Weighted average dividend yield (%)	**2.89**

(1) Risk-free interest rate is based on the weighted average Government of Canada benchmark bond yields for one, two, and three year terms to match corresponding vesting periods.

(2) The expected volatility is measured as the standard deviation of expected share price returns based on statistical analysis of historical weekly share prices for a representative period.

11. OIL AND GAS SALES, NET OF ROYALTIES

($ 000s)	**June 30, 2021**	June 30, 2020	**June 30, 2021**	June 30, 2020
Oil and gas sales				
Crude oil	**47,948**	16,835	**85,934**	48,740
Natural gas liquids	**3,225**	1,220	**6,510**	2,967
Natural gas	**7,990**	4,116	**15,513**	9,019
	59,163	22,171	**107,957**	60,726
Less royalties:				
Crown	**(3,470)**	(1,000)	**(5,332)**	(2,535)
Freehold, gross overriding royalties and other	**(2,560)**	(520)	**(4,484)**	(1,740)
	(6,030)	(1,520)	**(9,816)**	(4,275)
Oil and gas sales, net of royalties	**53,133**	20,651	**98,141**	56,451

12. FINANCIAL RISK MANAGEMENT

Financial Risk Factors

The Company undertakes transactions in a range of financial instruments including:

- Accounts receivable
- Accounts payable and accrued liabilities
- Common share investments
- Due to related party
- Subordinated promissory note
- Bank debt
- Subordinated debt

The Company's activities result in exposure to a number of financial risks including market risk (commodity price risk, interest rate risk, and foreign exchange risk), credit risk, liquidity risk and equity price risk.

The Company's overall risk management program seeks to mitigate these risks and reduce the volatility on the Company's financial performance. Financial risk is managed by senior management under the direction of the Board of Directors.

The Company is exposed to credit risk, liquidity risk and market risk as part of its normal course of business. The Company's overall risk management program seeks to mitigate these risks and reduce the volatility on the Company's financial performance. Financial risk is managed by senior management under the direction of the Board of Directors. The Company does not speculatively trade in risk management contracts. The Company's risk management contracts are entered into to manage the risks relating to commodity prices from its business activities. Certain financial risks have been increased due to the COVID-19 outbreak and have created abnormal volatility in spot prices and decreased demand for oil.

Liquidity Risk Management

Liquidity risk is the risk that the Company will encounter difficulty in meeting obligations associated with its financial liabilities. While commodity prices have stabilized since the outbreak of the COVID-19 pandemic there is still economic uncertainty as a result of new COVID-19 variants and varying levels of progress each country around the globe can administer vaccines will have impact the Company's financial performance and position, the Company continues to retain available committed borrowing capacity that provides the Company with financial flexibility and the ability to meet ongoing obligations as they become due.

After examining the economic factors that are causing the liquidity risk facing the Company, the judgment applied to these factors, and the various initiatives that the Company has and will undertake to strengthen its financial position, the Company believes it will have sufficient liquidity to support its ongoing operations and meet its financial obligations as they come due for at least the next twelve months. There can be no assurance that the next borrowing base redetermination will not result in a borrowing base shortfall, and that the necessary funds or additional security will be available to eliminate the short fall. Upon receipt of notice from the lenders, the shortfall would have to be remedied within 30 days or by such other means as acceptable to the lenders.

Credit Risk

Credit risk is the risk that a contracting party will not complete its obligations under a financial instrument and cause the Company to incur a financial loss. The Company is exposed to credit risk on all financial assets included on the statement of financial position. To help mitigate this risk:

- The Company only enters into material agreements with credit worthy counterparties. These include major oil and gas companies or major Canadian chartered banks; and
- Agreements for product sales are primarily on 30-day renewal terms. Of the $22,946,000 accounts receivable balance at June 30, 2021 (December 31, 2020 - $12,891,000) over 85 percent (2020 – 91 percent) relates to product sales or risk management contracts with national and international banks and oil and gas companies.

On a quarterly basis, the Company assesses if there has been any impairment of the financial assets of the Company. During the six months ended June 30, 2021, there was no material impairment provision required on any of the financial assets of the Company. The Company does have a credit risk exposure as the majority of the Company's accounts receivable are with counterparties having similar characteristics. However, payments from the Company's largest accounts receivable counterparties have consistently been received within 30 days and the sales agreements with these parties are cancellable with 30 days' notice if payments are not received.

At June 30, 2021, approximately $584,000 or 2.5 percent of the Company's total accounts receivable are aged over 90 days and considered past due (December 31, 2020 - $709,000 or 5.5 percent). The majority of these accounts are due from various joint venture partners. The Company actively monitors past due accounts and takes the necessary actions to expedite collection, which can include withholding production or netting payables when the accounts are with joint venture partners. Should the Company determine that the ultimate collection of a receivable is in doubt, it will provide the necessary provision in its allowance for doubtful accounts with a corresponding charge to earnings. If the Company subsequently determines an account is uncollectable, the account is written off with a corresponding charge to the allowance account. The Company's allowance for doubtful accounts balance at June 30, 2021 is $1,198,000 (December 31, 2020 - $1,186,000) with the expense being included in general and administrative expenses. There were no material accounts written off during the period.

The maximum exposure to credit risk is represented by the carrying amounts of accounts receivable. There are no material financial assets that the Company considers past due.

Capital Risk Management

The Company's objectives when managing capital, which the Company defines to include shareholders' equity, debt and working capital balances, are to safeguard the Company's ability to continue as a going concern, so that it can continue to provide returns to its shareholders and benefits for other stakeholders and to maintain a capital structure that provides a low cost of capital. In order to maintain or adjust the capital structure, the Company may adjust the current debt structure and/or issue common shares.

The Company monitors capital based on the ratio of net debt (total debt adjusted for working capital) to cash flow from operating activities. This ratio is calculated using each quarter end net debt divided by the preceding twelve months' cash flow. Management believes that a net debt level as high as one and a half year's cash flow is an optimal level to allow it to take advantage of future acquisition opportunities. During the current year the Company had a net debt to cash flow level of 8.2:1 compared to 9.8:1 as at December 31, 2020. The decrease in net debt to cash flow ratio is primarily due to an increase in commodity prices in the first six months of 2021. Net debt to cash flow ratio should improve in subsequent quarters with commodity prices stabilizing, increased production from the Company's capital program and having approximately thirty percent of the Company's forecasted production hedged. Bonterra has also optimized using any government assistance programs where applicable.

Section (a) of this note provides the Company's debt to cash flow from operations.

Section (b) addresses in more detail the key financial risk factors that arise from the Company's activities including its policies for managing these risks.

a) Net debt to cash flow ratio

The net debt and cash flow amounts are as follows:

($ 000s)	**June 30, 2021**	December 31, 2020
Bank debt[1]	**244,321**	252,255
Subordinated debt	**46,169**	28,161
Current liabilities	**57,642**	52,628
Current assets	**(28,822)**	(17,471)
Net debt	**319,310**	315,573
Cash flow from operations	**38,790**	32,073
Net debt to cash flow ratio	**8.2**	9.8

(1) Bank debt is classified as a current liability.

b) Risks and mitigation

Market risk is the risk that the fair value or future cash flow of the Company's financial instruments will fluctuate because of changes in market prices. Components of market risk to which the Company is exposed are discussed below.

Commodity Price Risk

The Company's principal operation is the production and sale of crude oil, natural gas and natural gas liquids. Fluctuations in prices of these commodities directly impact the Company's performance and ability to continue with its dividends.

The Company has used various risk management contracts to set price parameters for a portion of its production. The Company has assumed the risk in respect of commodity prices, except for a small portion of physical delivery sales and risk management contracts to manage commodity risk on the Company's higher operating cost areas.

The Company is exposed to credit risk, liquidity risk and market risk as part of its normal course of business. The Company's overall risk management program seeks to mitigate these risks and reduce the volatility on the Company's financial performance. Financial risk is managed by senior management under the direction of the Board of Directors.

Physical Delivery Sales Contracts

Bonterra enters into physical delivery sales contracts to manage commodity price risk. These contracts are considered normal executory sales contracts and are not recorded at fair value in the financial statements. As of June 30, 2021, the Company has the following physical delivery sales contracts in place.

Product	Type of contract	Volume	Term	Contract price ($)
Oil	Physical collar - WTI(1)	500 BBL/day	Jan 1, 2021 to Dec 31, 2021	37.00 to 47.70 USD/BBL
Oil	Fixed price - MSW differential(2)(3)	500 BBL/day	Jan 1, 2021 to Dec 31, 2021	(8.18)CAD/BBL
Oil	Physical collar - WTI(1)	250 BBL/day	Jan 1, 2022 to Mar 31, 2022	48.00 to 63.90 USD/BBL
Oil	Fixed price - MSW differential(2)(3)	250 BBL/day	Jan 1, 2022 to Mar 31, 2022	(5.00)CAD/BBL
Oil	Physical collar - WTI(1)	500 BBL/day	Apr 1, 2022 to Jun 30, 2022	48.00 to 75.50 USD/BBL
Gas	Fixed Price -AECO Daily(4)	2,500 GJ/day	Jan 1, 2021 to Dec 31, 2021	2.45 GJ/ day
Gas	Fixed Price -AECO Daily(4)	3,000 GJ/day	Nov 1, 2020 to Oct 31, 2021	2.79 GJ/ day
Gas	Fixed Price -AECO Daily(4)	2,000 GJ/day	Jan 1, 2022 to Mar 31, 2022	2.70 GJ/ day
Gas	Fixed Price -AECO Daily(4)	3,000 GJ/day	Nov 1, 2021 to Dec 31, 2021	2.47 GJ/ day
Gas	Fixed Price -AECO Daily(4)	3,000 GJ/day	Jan 1, 2022 to Mar 31, 2022	3.10 GJ/ day
Gas	Fixed Price -AECO Daily(4)	2,500 GJ/day	Jan 1, 2022 to Mar 31, 2022	2.65 GJ/ day
Gas	Fixed Price -AECO Daily(4)	2,000 GJ/day	Apr 1, 2022 to Jun 30, 2022	2.40 GJ/ day
Gas	Physical collar - AECO Monthly(5)	5,000 GJ/day	Apr 1, 2022 to Jun 30, 2022	2.00 to 2.60 GJ/ day

(1) "WTI" refers to West Texas Intermediate, a grade of light sweet crude oil used as benchmark pricing in the United States.
(2) "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.
(3) "MSW differential" is the primary difference between WTI and MSW steam index benchmark pricing.
(4) "AECO Daily" refers to a grade or heating content of natural gas used as daily index benchmark pricing in Alberta, Canada.
(5) "AECO Monthly" refers to a grade or heating content of natural gas used as monthly index benchmark pricing in Alberta, Canada.

Subsequent to June 30, 2021, the Company entered into the following physical delivery sales contracts.

Product	Type of contract	Volume	Term	Contract price ($)
Oil	Physical collar - WTI	500 BBL/day	Apr 1, 2022 to Jun 30, 2022	48.00 to 77.00 USD/BBL
Oil	Fixed price - MSW differential	500 BBL/day	Apr 1, 2022 to Jun 30, 2022	(5.25) USD/BBL
Gas	Physical collar - AECO Monthly	5,000 GJ/day	Jul 1, 2022 to Sep 30, 2022	2.50 to 3.15 GJ/ day

Risk Management Contracts

($ 000s)	Three months June 30, 2021	June 30, 2020	Six months June 30, 2021	June 30, 2020
Risk management contracts				
Realized gain (loss)	**(3,910)**	877	**(5,876)**	2,465
Unrealized gain (loss)	**(5,070)**	(2,950)	**(9,920)**	(1,154)
	(8,980)	(2,073)	**(15,796)**	1,311

The Company also enters into financial derivative instruments or risk management contracts to manage commodity price risk. These contracts are not considered normal executory sales contracts and are recorded at fair value in the financial statements. The Company has entered into the following risk management contracts during the period ended June 30, 2021.

Product	Type of contract	Volume	Term	Contract price ($)
Oil	Financial collar -WTI	500 BBL/day	Jan 1, 2021 to Dec 31, 2021	37.00 to 48.00 USD/BBL
Oil	Fixed price - MSW differential	500 BBL/day	Jan 1, 2021 to Dec 31, 2021	(7.26) CAD/BBL
Oil	Financial collar -WTI	250 BBL/day	Jan 1, 2021 to Dec 31, 2021	36.00 to 50.05 USD/BBL
Oil	Financial collar -WTI	250 BBL/day	Jan 1, 2021 to Dec 31, 2021	38.00 to 50.50 USD/BBL
Oil	Fixed price - MSW differential	250 BBL/day	Mar 1, 2021 to Dec 31 2021	(6.34) CAD/BBL
Oil	Fixed price - MSW differential	250 BBL/day	Jan 1, 2021 to Dec 31 2021	(8.10) CAD/BBL
Oil	Financial collar -WTI	500 BBL/day	Jan 1, 2021 to Dec 31, 2021	36.00 to 48.75 USD/BBL
Oil	Fixed price - MSW differential	500 BBL/day	Jan 1, 2021 to Dec 31, 2021	(7.15) CAD/BBL
Oil	Financial collar -WTI	250 BBL/day	Jan 1, 2021 to Dec 31, 2021	36.00 to 48.90 USD/BBL
Oil	Financial collar -WTI	1,000 BBL/day	Jan 1, 2022 to Mar 31, 2022	48.00 to 64.60 USD/BBL
Oil	Financial collar -WTI	500 BBL/day	Jan 1, 2022 to Mar 31, 2022	48.00 to 68.00 USD/BBL
Oil	Financial collar -WTI	500 BBL/day	Jan 1, 2022 to Mar 31, 2022	48.00 to 68.50 USD/BBL
Oil	Fixed price - MSW differential	1,000 BBL/day	Jan 1, 2022 to Mar 31, 2022	(6.60) CAD/BBL
Oil	Financial collar -WTI	500 BBL/day	Apr 1, 2022 to Jun 30, 2022	48.00 to 68.90 USD/BBL
Oil	Financial collar -WTI	500 BBL/day	Apr 1, 2022 to Jun 30, 2022	48.00 to 73.10 USD/BBL
Oil	Fixed price - MSW differential	1,000 BBL/day	Apr 1, 2022 to Jun 30, 2022	(6.55) CAD/BBL
Oil	Financial collar -WTI	300 BBL/day	Apr 1, 2022 to Jun 30, 2022	48.00 to 79.75 USD/BBL
Oil	Fixed price - MSW differential	300 BBL/day	Apr 1, 2022 to Jun 30, 2022	(4.75) USD/BBL
Gas	Fixed Price -AECO Daily	1,800 GJ/day	Jan 1, 2021 to Dec 31, 2021	2.24 GJ/ day

Interest Rate Risk

Interest rate risk refers to the risk that the value of a financial instrument or cash flows associated with the instrument will fluctuate due to changes in market interest rates. Interest rate risk arises from interest bearing financial assets and liabilities that the Company uses. The principal exposure of the Company is on its borrowings which have a variable interest rate which gives rise to a cash flow interest rate risk.

The Company's debt facilities consist of a $175,000,000 syndicated revolving credit facility, a $25,000,000 non-syndicated revolving credit facility and a term loan of $65,000,000, $45,000,000 subordinated debt, $12,707,000 due to a related party and a $7,603,000 subordinated promissory note. The borrowings under the total bank facilities are at bank prime plus or minus various percentages as well as by means of banker's acceptances ("BAs") within the Company's credit facility. Due to related party and the subordinated promissory note are at a fixed interest rate of 5.5 percent and the subordinated debt is at fixed interest rate of five percent in the first year. The Company manages its exposure to interest rate risk on its floating interest rate debt through entering into various term lengths on its BAs but in no circumstances do the terms exceed six months.

Sensitivity Analysis

Based on historic movements and volatilities in the interest rate markets and management's current assessment of the financial markets, the Company believes that a one percent variation in the Canadian prime interest rate is reasonably possible over a 12 month period.

A one percent increase (decrease) in the Canadian prime rate would decrease (increase) both annual net earnings and comprehensive income by $1,881,000.

Equity Price Risk

Equity price risk refers to the risk that the fair value of the investments and investment in related party will fluctuate due to changes in equity markets. Equity price risk arises from the realizable value of the investments that the Company holds which are subject to variable equity market prices which on disposition gives rise to a cash flow equity price risk. The Company will assume full risk in respect of equity price fluctuations.

Foreign Exchange Risk

The Company has no foreign operations and currently sells all of its product sales in Canadian currency. The Company however is exposed to currency risk in that crude oil is priced in US currency, then converted to Canadian currency. The Company currently has no outstanding risk management agreements. The Company will assume full risk in respect of foreign exchange fluctuations.

13. COMMITMENTS AND FINANCIAL LIABILITIES

The Company has the following maturity schedule for its financial liabilities and commitments:

($ 000s)	Recognized on Financial Statements	Less than 1 year	Over 1 year to 3 years	Over 3 years to 5 years	Over 5 years to 7 years	Total
Accounts payable and accrued liabilities	Yes - Liability	22,658	-	-	-	22,658
Due to related parties	Yes - Liability	12,707	-	-	-	12,707
Suboridinated promissory note	Yes - Liability	7,603	-	-	-	7,603
Bank Debt	Yes - Liability	244,321	-	-	-	244,321
Subordinated debt	Yes - Liability	-	-	46,169	-	46,169
Firm service commitments	No	81	161	144	8	394
Office lease commitments	No	519	520	222	-	1,261
Total		287,889	681	46,535	8	335,113

The Company has entered into firm service gas transportation agreements in which the Company guarantees certain minimum volumes of natural gas will be shipped on various gas transportation systems. The terms of the various agreements expire in one to seven years. The future minimum payment amounts for the firm service gas transportation agreements are calculated using current tariff rates.

The Company also has non-cancellable office lease commitments for building and office equipment. The building and office equipment leases have an average remaining life of 2.4 years.

14. GOVERNMENT GRANTS

The Government of Alberta's Site Rehabilitation Program ("SRP") provides grant funding through service providers to abandon or remediate oil and gas sites. The Company derecognized approximately $3,422,000 of asset retirement obligations as an in-kind grant (June 30, 2020 - $Nil). The benefit of the in-kind grant is recognized through other income.

Canadian Emergency Wage Subsidy ("CEWS") is a federal program that allows eligible companies to receive a subsidy of employee wages, subject to a maximum per employee. During the six month period ended June 30, 2021, the Company received $159,000 (2020 - $367,000), which resulted in a reduction of employee compensation.

Corporate Information

Board of Directors
D. Michael G. Stewart - Chair
John J. Campbell
George F. Fink
Jacqueline R. Ricci
Rodger A. Tourigny

Officers
George F. Fink, CEO
Robb D. Thompson, CFO and Corporate Secretary
Adrian Neumann, Chief Operating Officer
Brad A. Curtis, Senior VP, Business Development

Registrar and Transfer Agent
Odyssey Trust Company

Auditors
Deloitte LLP

Solicitors
Borden Ladner Gervais LLP

Bankers
CIBC
National Bank of Canada
The Toronto-Dominion Bank
ATB Financial
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