Bonterra Energy Corp.

YIELD SUSTAINABILITY GROWTH

ANNUAL REPORT 2012

THE **RIGHT ASSETS.** THE **RIGHT PEOPLE.** THE **RIGHT STRATEGY.**

Bonterra Energy Corp. is a high-yield, dividend paying oil and gas company headquartered in Calgary, Alberta, Canada with a proven history of creating growth and long-term value for shareholders on a per share basis. Bonterra has paid a monthly dividend (distribution) since inception and intends to pay approximately 50 to 65 percent of funds flow to investors. Bonterra's successful performance is due to its experienced management team, conservative capital structure and sustainable pace of development.

Bonterra's shares trade on the Toronto Stock Exchange under the symbol BNE.

2012 HIGHLIGHTS

Bonterra's business strategy is to provide income to shareholders on a monthly basis in the form of a monthly dividend and to generate above average returns for shareholders over time through the development and expansion of its high quality asset base.

The company's conservative capital structure along with its large drilling inventory and efficient horizontal drilling program positions the company well to continue to provide superior value to its shareholders.

$3.12
per share
paid out in 2012

90.5%
five year return
to shareholders

Bonterra's operations are characterized by a long reserve life index and low risk, predictable returns. The company focuses on the sustainable development of its asset base through a steady pace of development and efficient operating practices. Bonterra's implementation of new drilling and completion methods have decreased costs and improved well performance and reserve recovery. The company will continue to execute its disciplined approach to operations in 2013 to maximize shareholder returns on a long-term basis.

$90 M
2013 capital
program

>10 year
drilling
inventory

Bonterra's track record of production, reserves and dividend growth on both a total and per share basis remains unparalleled in the Canadian energy industry. Bonterra has increased its holdings in the Cardium during 2012 and its 2013 horizontal drill program will continue to drive growth as the company pursues the development of its opportunities in both the Pembina and Willesden Green fields. Bonterra will maintain its focus on providing superior growth to shareholders balanced by conservative financial management.

6,703
BOE per day
produced in 2012

100%
drilling success
rate in 2012

ANNUAL **HIGHLIGHTS**

As at and for the year ended ($ 000s except $ per share)		**December 31, 2012**	December 31, 2011	December 31, 2010
FINANCIAL				
Revenue – realized oil and gas sales		**142,770**	162,277	118,980
Funds flow (1)		**80,429**	101,988	74,385
Per share – basic		**4.07**	5.27	3.95
Per share – diluted		**4.06**	5.22	3.84
Payout ratio (2)		**77%**	58%	64%
Cash flow from operations		**74,325**	97,409	66,238
Per share – basic		**3.75**	5.04	3.52
Per share – diluted		**3.75**	4.98	3.42
Payout ratio (2)		**83%**	61%	72%
Cash dividends per share (2)		**3.12**	3.06	2.55
Net earnings		**33,211**	43,608	39,954
Per share – basic		**1.68**	2.25	2.12
Per share – diluted		**1.68**	2.23	2.06
Capital expenditures and acquisitions net of dispositions		**98,130**(3)	62,686	70,680
Total assets		**419,933**	364,176	347,825
Working capital deficiency		**29,876**	51,576	17,905
Long-term debt		**166,808**	69,916	85,386
Shareholders' equity		**163,277**	181,640	190,173
OPERATIONS				
Oil	– barrels per day	**4,035**	4,075	3,585
	– average price ($ per barrel)	**82.04**	92.76	74.76
NGLs	– barrels per day	**476**	386	290
	– average price ($ per barrel)	**52.18**	60.89	47.11
Natural gas	– MCF per day	**13,157**	11,163	10,521
	– average price ($ per MCF)	**2.60**	3.86	4.14
Total barrels of oil equivalent per day (BOE) (4)		**6,703**	6,322	5,628

(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, decommissioning expenditures settled and restricted cash.

(2) Cash dividends per share are based on payments made in respect of production months within the quarter.

(3) Includes an acquisition that closed on June 7, 2012 for $17,108,000.

(4) BOE may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 MCF: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

QUARTERLY **HIGHLIGHTS**

As at and for the periods ended ($ 000s except $ per share)	2012 Q4	Q3	Q2	Q1
FINANCIAL				
Revenue – realized oil and gas sales	**39,624**	35,204	31,049	36,893
Funds flow [(1)]	**19,796**	21,705	16,621	22,307
Per share – basic	**1.00**	1.10	0.84	1.13
Per share – diluted	**1.00**	1.09	0.84	1.13
Payout ratio [(2)]	**78%**	71%	93%	69%
Cash flow from operations	**21,460**	16,440	14,727	21,698
Per share – basic	**1.08**	0.83	0.74	1.10
Per share – diluted	**1.08**	0.83	0.74	1.10
Payout ratio [(2)]	**72%**	94%	105%	71%
Cash dividends per share [(2)]	**0.78**	0.78	0.78	0.78
Net earnings	**6,082**	7,746	9,201	10,182
Per share – basic	**0.31**	0.39	0.47	0.52
Per share – diluted	**0.31**	0.39	0.46	0.51
Capital expenditures and acquisitions, net of disposals	**24,069**	27,360	25,288[(3)]	21,413
Total assets	**419,933**	412,812	393,772	371,757
Working capital deficiency	**29,876**	49,808	42,082	57,889
Long-term debt	**166,808**	128,779	114,747	75,543
Shareholders' equity	**163,277**	169,839	176,292	181,008
OPERATIONS				
Oil (barrels per day)	**4,400**	4,108	3,650	3,975
NGLs (barrels per day)	**595**	461	428	419
Natural gas (MCF per day)	**16,009**	12,583	11,753	12,260
Total BOE per day [(4)]	**7,663**	6,666	6,037	6,438

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(2) Cash dividends per share are based on payments made in respect of production months within the quarter.

(3) Includes an acquisition that closed on June 7, 2012 for $17,108,000.

(4) Barrels of oil equivalent (BOE) may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 MCF: 1 bbl is based on an energy equivalency 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 report its financial and operational results for the year ended December 31, 2012.

STRATEGY

It was a challenging year for the Canadian energy sector, including Bonterra, as the operating environment was hampered by a number of significant issues including an extended spring break-up, weak commodity prices, including volatile price differentials between WTI and average realized prices, lengthy plant turnarounds and pipeline issues. Despite these hurdles, Bonterra continued to create value for its shareholders through the successful execution of its long-term business strategy which is focused on:

- providing shareholders with income in the form of a monthly dividend;
- potential share price appreciation by growing production and reserves on both a total and per share basis through the execution of a sustainable development program and the efficient management of its high-quality, low risk asset base; and
- preserving balance sheet strength.

Bonterra continues to offer above average returns to investors. Since inception Bonterra has provided investors with a compound annual rate of return of over 40 percent and the Company's five year return to shareholders is 90.5 percent.

2012 highlights include:

- Paid $3.12 per share ($0.26 per share monthly) in dividends to shareholders that has been increased to $0.28 per share monthly effective March 31, 2013;
- Executed an $81.0 million capital program before acquisitions comprised of 34 gross (22.9 net) Cardium horizontal wells drilled with a 100 percent success rate;
- New production records set with average daily production of 6,703 barrels of oil equivalent (BOE) per day (67 percent oil and liquids) for the full year 2012 and 7,663 BOE per day in the fourth quarter, an increase of 6.0 percent and 14.8 percent over the same periods in 2011;
- Production per share was 0.124 BOE per share, an increase of 4.2 percent over 2011;
- Proved plus Probable (P+P) reserves of 45.0 million BOE (approximately 75 percent oil and liquids), a 9.4 percent increase over December 2011 reserves of 41.1 million BOE;
- Added a total of 6.3 million BOE of reserves (P+P) which equates to 2.5 times 2012 production;
- Reserves per share (P+P) increased 7.0 percent to 2.28 BOE per share compared to 2.13 BOE per share in the prior year; and
- The Company was successful in strengthening its Cardium core area with two key acquisitions.

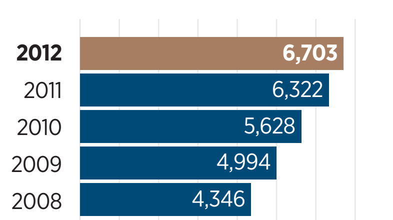
2012 challenges include:

- The debt to funds flow ratio at December 31, 2012 was in excess of the Company's guidance of 1.5 to 1 times. (This has been rectified in 2013);
- A reduction of $11.11 in corporate netbacks per BOE from $42.47 in 2011 to $31.36 in 2012 due to: the average annual oil differential between the price of WTI and the Company's realized price of $12.07 in 2012 compared to $2.42 in 2011; the reduction of natural gas prices from $3.86 per MCF in 2011 to $2.60 per MCF in 2012; and the reduction of natural gas liquids from $60.89 per barrel in 2011 to $52.18 per barrel in 2012. The decrease in corporate netbacks using 2012 average production reduced cash flow by $27.2 million; and
- The Company exceeded its capital expenditure budget by approximately $30 million in 2012 due to an unbudgeted $17 million acquisition and additional drilling in Q4 2012. Bonterra had considered issuing shares from treasury in December 2012 to finance this increase in capital spending and the negative effect on the debt to funds flow ratio but did not need to proceed with this after the Spartan Oil Corp. acquisition which closed in January 2013.

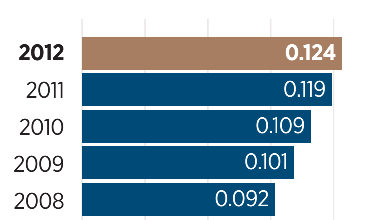
ASSETS

Bonterra holds an enviable suite of light oil properties in its core area in the Cardium located in the Pembina and Willesden Green fields in west central Alberta. Horizontal drilling has revitalized this mature basin and the Company has been at the forefront of increased development having drilled the first horizontal well in the halo of the Pembina field that commenced production in February 2009. The Company's high level of concentration and experience in the area provides Bonterra with the knowledge to efficiently exploit the Cardium

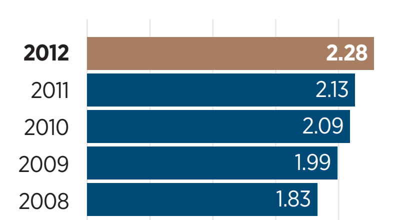
AVERAGE DAILY PRODUCTION
(BOE PER DAY)



PRODUCTION PER SHARE
(BOE)



RESERVES PER SHARE
(BOE)



formation and the Company has pursued land and corporate acquisitions to continue to acquire further interests in this key resource play.

During the second quarter of 2012, Bonterra completed a tuck-in acquisition in the Willesden Green area adding 52.3 gross (10.5 net) sections of land and 250 BOE per day of production, net to the Company. These lands are considered underdeveloped and provide Bonterra with an additional 191 gross (37 net) potential Cardium drilling locations.

In late 2012, Bonterra announced its most significant acquisition to date of a Cardium-focused producer Spartan Oil Corp. (Spartan) which closed on January 25, 2013. The Spartan assets further solidified Bonterra's position as one of the predominant sustaining light-oil dividend paying companies in the Canadian energy sector, augmented Bonterra's large asset base in the Cardium formation which now totals 250.3 (193.7 net) sections and increased production to approximately 13,500 BOE per day of production at the date of acquisition. The Spartan assets are expected to increase Bonterra's liquids weighting and the corporate production profile in 2013 is anticipated to be approximately 75 percent light oil and natural gas liquids which should result in increased netbacks.

The Company currently estimates that it has a greater than 10 year drilling inventory (based on drilling four horizontal wells per section) and remains well-positioned to continue delivering strong operational performance in 2013 through the continued development of its significant portfolio of organic growth opportunities. Bonterra will focus its efforts on improving production rates, sustaining a consistent pace of development and increasing project economics across its operations.

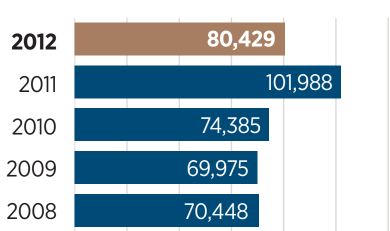
FINANCIAL RESULTS AND COMMODITY PRICE ENVIRONMENT

Oil and natural gas prices exhibited continued weakness in 2012 and price differentials between Bonterra's average realized price and WTI widened substantially from prices received in 2011, due in most part to pipeline capacity constraints, refinery outages, seasonal turnarounds and quality adjustments. The price differential slightly decreased during the fourth quarter of 2012 due to a combination of increased rail shipments, decreased production of Alberta synthetic crude and increased demand from U.S. and Canadian refineries. However, continued European and North American economic concerns and pipeline capacity constraints continued to negatively affect the realized price for oil in Canada.

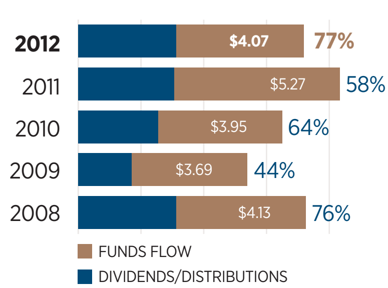
The Company's average realized price for crude oil was $82.04 per barrel, a decrease of approximately 11.6 percent when compared to 2011. In addition, natural gas prices continued to remain extremely weak and Bonterra's average realized price decreased 32.6 percent to $2.60 per MCF in 2012 when compared to $3.86 per MCF in 2011.

Mainly as a result of this lower price environment, revenue and cash flow from operations decreased 12.0 percent and 23.7 percent, respectively, year over year. However, Bonterra's strong operating results in 2012 along with the substantial increase in production volumes allowed the Company to maintain the monthly dividend level to shareholders at $0.26 per share, representing a payout ratio of 77 percent of funds flow. Higher production volumes will, subject to commodity prices, assist in reducing this payout ratio further in 2013.

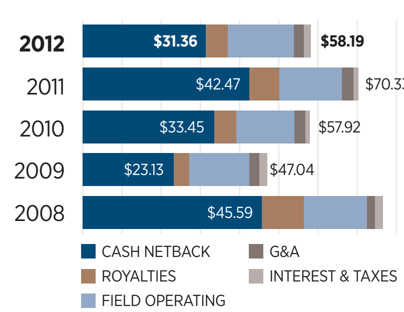
FUNDS FLOW
($ THOUSANDS)



CASH DIVIDENDS/ DISTRIBUTIONS TO INVESTORS
($ PER UNIT/SHARE)



NETBACKS
($ PER BOE)



A number of pipeline expansions and reversals of flow direction currently underway could alleviate pipeline capacity issues later in 2013 and 2014. In addition, there are a number of pipeline initiatives under review including the Keystone XL pipeline in the United States and the Northern Gateway pipeline in Canada. However, neither of these has received government or regulatory approval at this time and Bonterra will continue to focus on managing its funds flow, capital expenditure ranges and dividend payments within the current commodity environment.

A conservative approach to the Company's capital structures has been a key factor in building financial strength and flexibility. Bonterra retains its strong financial position by maintaining a sustainable growth strategy and minimizing the amount and cost of debt. The Company's current net debt to funds flow ratio is less than 1.5 times (after the closing of the Spartan acquisition) and Bonterra is well funded to execute the 2013 capital program and to pursue any additional acquisition opportunities that may become available.

Bonterra currently has approximately $600.0 million in tax pools, $27.7 million in investment tax credits and $135.7 million of capital loss carry forwards (which can only be claimed against taxable capital gains). The Company anticipates that these pools move Bonterra's tax horizon beyond 2015.

Bonterra's 2013 capital development program is focused on sustaining its current business model offering both solid growth and yield to its shareholders.

2013 OUTLOOK

Bonterra's 2013 capital development program is focused on sustaining its current business model offering both solid growth and yield to its shareholders. The Board of Directors has approved a capital development program of $90.0 million which mainly targets light oil prospects through its Cardium horizontal drill program. The program plan in 2013 is to:

- Maintain a steady pace of development and manage annual decline levels. Bonterra anticipates allowing current production levels to reduce to an average daily production rate of approximately 12,000 BOE per day;
- Drill 29 gross (28.1 net) operated horizontal wells and participate in drilling 13 gross (4.3 net) non-operated wells;
- Seek out additional operating efficiencies and control costs. Operating expenditures are expected to average approximately $13.00 per BOE on an annualized basis;
- Ensure sustainability by managing the dividend payout ratio to range between 50 and 65 percent of funds flow in 2013;
- Manage risk by maintaining balance sheet strength. Bonterra anticipates maintaining its net debt to cash flow ratio at less than 1.5 times in 2013; and
- Continue to provide increased value to shareholders. Bonterra increased the monthly dividend to $0.28 per share beginning in March 2013. Bonterra's Board of Directors and management will continue to take into account production volumes and commodity prices in determining monthly dividend amounts and will consider increasing the dividend should crude oil pricing remain favourable coupled with anticipated production increases.

THE RIGHT PEOPLE

Bonterra's successful execution of its long-term strategy has been dependent on the strength of its people. The Company's Board of Directors, management team, employees and field staff have been instrumental in providing continued growth and results on behalf of shareholders. We would like to thank these people for their continued efforts in 2012 as the Company looks forward to another year of growth for both its operations and its investors.

This will be an exciting year for both Bonterra and its shareholders. We would also like to take this opportunity to thank our long-term shareholders for their continued support as well as welcome our new shareholders through the Spartan acquisition. The Company is committed to continue to create and deliver outstanding value on behalf of its investors and will continue to pursue the aggressive development of its light oil targets in the Cardium to drive future growth. The Company's disciplined approach to its operations in 2013 should allow Bonterra to continue to capitalize on its numerous opportunities and maximize shareholder value on a long-term basis.

George F. Fink
Chief Executive Officer and Chairman of the Board

CARDIUM:
THE **RIGHT ASSETS.**

OPERATIONS

Bonterra continues to provide value to shareholders through its holdings in the Pembina Cardium in central Alberta, one of Canada's largest oil fields. The pool is characterized by stable production, high quality oil and high netbacks with only 14 percent of original oil in place having been produced.

During 2012 and 2013, Bonterra increased its land position in the Cardium through two key acquisitions and this concentrated asset base now represents approximately 93 percent of Bonterra's Proved plus Probable (P+P) reserves. The acquisitions were a strong strategic fit for the Company resulting in significant development potential and ongoing value creation.

The revitalization of the Cardium through horizontal drilling and completion technology has marked an evolution in the Company's pool exploitation strategy from conventional development to a more resource play-based development program. However, Bonterra's fundamental operational strategy remains unchanged; provide production and reserves growth on both a total and per share basis, effectively manage costs and seek out new operational efficiencies.

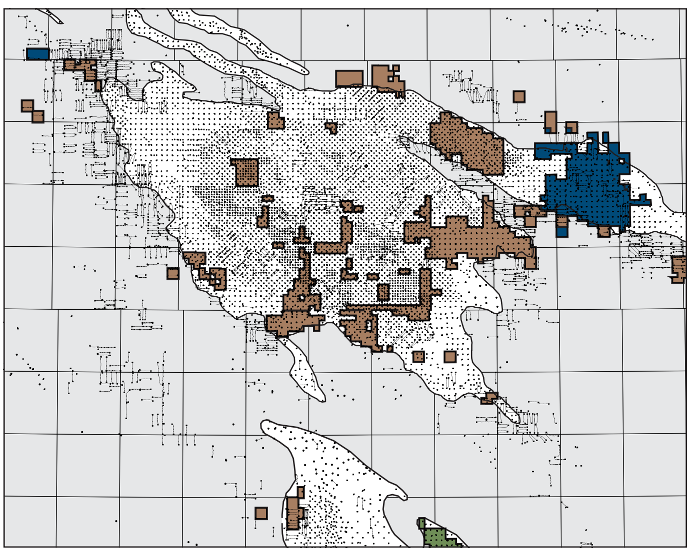
STRENGTHENING OUR POSITION

In 2012, Bonterra focused on consolidating and developing its Cardium core area and completed two acquisitions which increased its significant land position and met its acquisition criteria of high-quality production, significant reserves, operational efficiencies and upside potential.

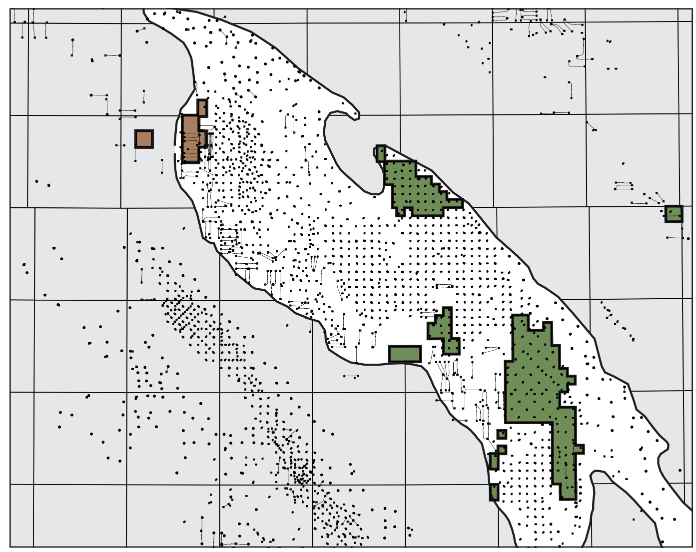
In the second quarter of 2012, Bonterra completed a tuck-in acquisition in the Willesden Green field of 52.3 gross (10.5 net) sections and most significantly, in late 2012 announced its largest acquisition to date of Spartan Oil Corp. (Spartan) which closed in January 2013. The Spartan assets included 60.75 gross (51.34 net) sections and the Company's large, concentrated asset base in the Cardium now totals 250.3 gross (193.7 net) sections.

The Spartan properties are a strong geographical fit to Bonterra's asset base, have significant operational synergies, provide additional drilling inventory over the long-term and are anticipated to increase the Company's 2013 oil and liquids weighting. Bonterra has completed extensive geological mapping of the Spartan land base and has fully integrated the assets into its 2013 capital program.

PEMBINA CARDIUM LAND BASE



WILLESDEN GREEN CARDIUM LAND BASE



BONTERRA LANDS   SPARTAN AQUISITION   WILLESDEN GREEN ACQUISITION

Corporate Overview

- Average Working Interest – 77%
- Reserve Life Index (P+P) – 16.1 years
- Proved + Probable Reserves – 70.5 MBOE
- Land Position – 250.3 gross (193.7 net) sections
- Booked Locations – 219 gross; 178.4 net

2012 Highlights

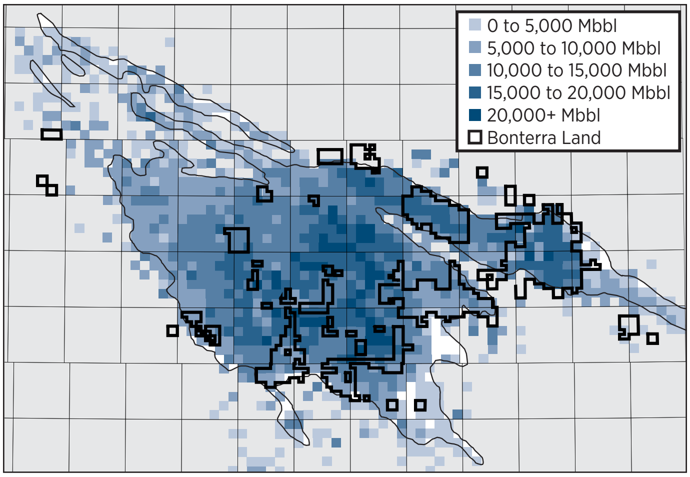
- 2012 Average Daily Production 6,703 BOE per day
- 34 gross (22.9 net) horizontal wells drilled
- Production per share increased 4.2% to 0.124 BOE per share
- P+P reserves increased 9.4 percent to 45.0 million BOE
- Reserve per share increased (P+P) increased 7.0% to 2.28 BOE per share

2013 Guidance

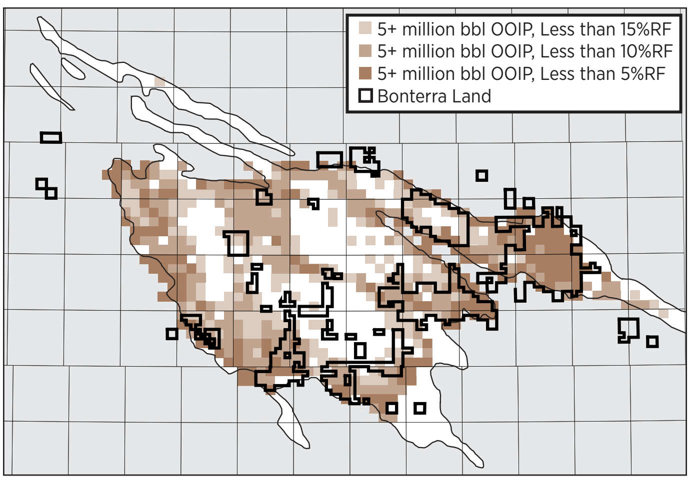
- Average Daily Production 12,000 BOE per day
- Production Profile – 75% Liquids; 25% Gas
- Operating Costs – $13.00 per BOE
- Capital Budget – $90 million
- Drilling Program – 29 gross (28.1 net) operated and 13 gross (4.3 net) non-operated horizontal wells
- Average Well Costs – $2.7 million

PEMBINA CARDIUM MAIN POOL

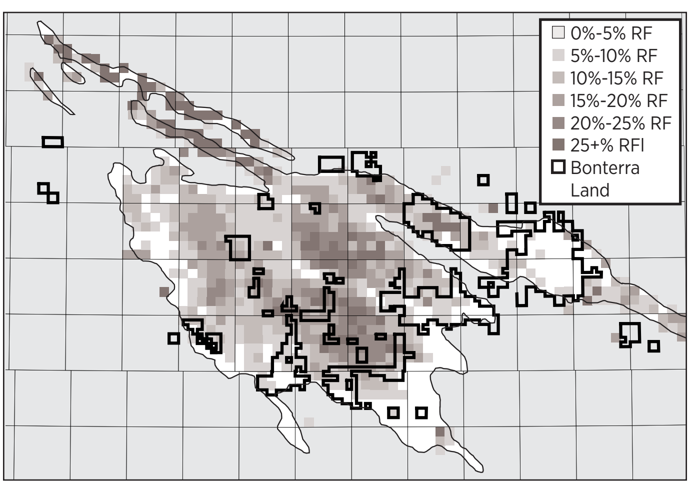
ORIGINAL OIL IN PLACE



HIGH AMOUNTS OF ORIGINAL OIL IN PLACE WITH LOW RECOVERY FACTOR



CURRENT RECOVERY FACTOR



MOMENTUM IN 2013

In 2013, Bonterra will execute a disciplined $90 million capital program focused on its oil weighted opportunities in the Cardium Formation. Bonterra has continued to improve and refine its Cardium development strategy to both increase well performance and reserve recoveries while minimizing costs. In 2013, Bonterra will drill several different areas within the Pembina and Willesden Green fields and expects to transition to pad drilling in the future once delineation drilling is completed.

As shown in these three maps, the majority of Bonterra's land position in the Pembina Cardium pool covers areas with high original oil in place and low current recovery factors. The Spartan transaction added a significant land position in areas exhibiting these highly prospective characteristics. The company is currently assessing additional opportunities to further increase both recovery factors and rates of return on its large asset base.

The Company recently completed a reservoir simulation model to investigate optimal well densities, fracture spacing and wellbore orientations in the Pembina field. The simulation suggested that in some cases, increased well densities will result in higher recoveries and ultimately higher rates of return. The simulation also investigated the potential for secondary recovery methods. Bonterra will use these findings to further calibrate its development of the Cardium and optimize overall recoveries.

Bonterra has continued to improve and refine its Cardium development strategy to both increase well performance and reserve recoveries while minimizing costs.

OPTIMIZING PERFORMANCE

Bonterra's operating strategy is aimed at enhancing cash flow over the long-term to maintain sustainability in the dividends paid to investors. Bonterra's commitment to operational and technical excellence helps to reduce development risks and lower operating costs, thus allowing the Company to maximize netbacks.

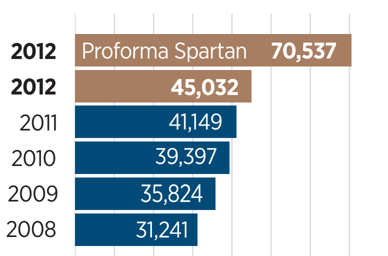
A strong focus for Bonterra's technical team in 2013 will be continued optimization across its operations. Bonterra has been refining its frac placement methods and fluid types to decrease capital costs. In 2012, the Company fully transitioned to water-based fracs which has significantly reduced overall well costs and increased per well production results. In 2013, Bonterra is currently targeting drilling, completion, equipping and tie-in costs to average approximately $2.7 million per well.

The Spartan assets delivered significant efficiencies including a 100 percent owned gas plant and will provide the opportunity for further facility consolidations. In addition, Spartan realized significant capital savings through a monobore well design and pad drilling in the Keystone Unit No. 2 to the point in which Spartan's average spud to rig release averaged just seven days. Bonterra expects to realize similar efficiencies as it transitions into similar drilling scenarios in the future.

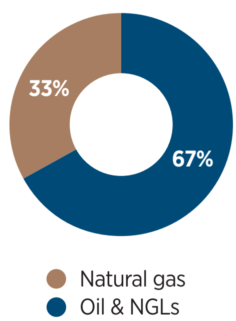
Bonterra operates approximately 88.5 percent of its total production, thereby allowing the Company to better manage costs and efficiently invest capital. Bonterra is able to strategically schedule development programs and well workovers to control its pace as well as manage its corporate decline through the prudent use of capital and selective timing of its drilling program to deliver sustainable and consistent growth to its shareholders.

Bonterra's commitment to operational and technical excellence helps to reduce development risks and lower operating costs, thus allowing the Company to maximize netbacks.

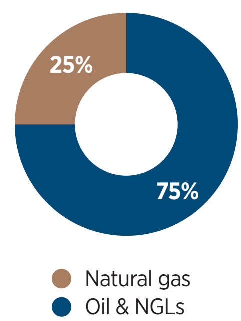
PROVED PLUS PROBABLE RESERVES (MBOE)



2012 PRODUCTION BY COMMODITY



2012 RESERVES BY COMMODITY



STATISTICAL REVIEW

CORPORATE RESERVES INFORMATION:

Bonterra engaged the services of Sproule Associates Limited to prepare a reserve evaluation with an effective date of December 31, 2012. The reserves are located in the provinces of Alberta, British Columbia and Saskatchewan. The gross reserve figures from the following tables represent Bonterra's ownership interest before royalties and before consideration of the Company's royalty interests. Tables may not add due to rounding.

SUMMARY OF GROSS OIL AND GAS RESERVES AS OF DECEMBER 31, 2012

Reserve category:	Light and medium oil (Mbbl)	Natural gas (Mmcf)	Natural gas liquids (Mbbl)	BOE[1] (MBOE)
PROVED				
Developed producing	14,415.7	33,037	1,365.7	21,287.6
Developed non-producing	366.3	2,629	51.8	856.3
Undeveloped	8,151.6	13,592	573.5	10,990.4
TOTAL PROVED	22,933.6	49,258	1,991.0	33,134.3
PROBABLE	8,013.1	18,963	724.0	11,897.6
TOTAL PROVED PLUS PROBABLE	30,946.7	68,221	2,715.0	45,031.9

RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT TYPE AS OF DECEMBER 31, 2012

	Light and medium oil and natural gas liquids		Natural gas		BOE[1]	
	Proved (Mbbl)	Proved plus probable (Mbbl)	Proved (Mmcf)	Proved plus probable (Mmcf)	Proved (MBOE)	Proved plus probable (MBOE)
December 31, 2011	21,160.1	30,492.4	41,822	63,941	28,130.4	41,149.2
Extension	1,142.7	1,403.6	1,279	1,624	1,355.9	1,674.3
Improved recovery	4,482.4	5,792.5	7,769	10,039	5,777.2	7,465.7
Technical revisions	(883.1)	(3,470.0)	403	(5,052)	(815.9)	(4,312.0)
Discoveries	-	-	-	-	-	-
Acquisitions	770.0	1,200.3	2,685	3,769	1,217.5	1,828.5
Dispositions	-	-	-	-	-	-
Economic factors	(158.7)	(168.4)	(564)	(1,964)	(252.7)	(495.7)
Production	(1,588.8)	(1,588.8)	(4,136)	(4,136)	(2,278.1)	(2,278.1)
December 31, 2012	**24,924.6**	**33,661.7**	**49,258**	**68,221**	**33,134.3**	**45,031.9**

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2012

	Net present value before income taxes discounted at (% per year)		
($ Millions)	0%	5%	10%
Reserve category:			
PROVED			
Developed producing	841.9	542.9	406.5
Developed non-producing	26.8	16.5	11.5
Undeveloped	393.1	191.5	96.2
TOTAL PROVED	1,261.8	750.9	514.2
PROBABLE	614.6	236.0	118.7
TOTAL PROVED PLUS PROBABLE	1,876.4	986.9	632.9

CHANGES TO RESERVES AFTER DECEMBER 31, 2012

On January 25, 2013, Bonterra completed the acquisition of Spartan Oil Corp. (Spartan). Spartan engaged the services of Sproule Associates Limited to prepare a reserve evaluation with an effective date of December 31, 2012. The gross reserve figures from the following tables represent Spartan's ownership interest before royalties and before consideration of the company's royalty interests at December 31, 2012.

SUMMARY OF GROSS OIL AND GAS RESERVES AS OF DECEMBER 31, 2012 (SPARTAN)

Reserve category:	Light and medium oil (Mbbl)	Natural gas (Mmcf)	Natural gas liquids (Mbbl)	BOE[1] (MBOE)
PROVED				
Developed producing	6,019.8	9,762	462.8	8,109.6
Developed non-producing	600.2	685	37.9	752.3
Undeveloped	8,115.4	10,005	533.2	10,316.1
TOTAL PROVED	14,735.4	20,452	1,033.9	19,177.9
PROBABLE	4,941.0	6,411	317.9	6,327.4
TOTAL PROVED PLUS PROBABLE	19,676.4	26,863	1,351.7	25,505.3

RECONCILIATION OF COMPANY GROSS RESERVES BY PRINCIPAL PRODUCT TYPE AS OF DECEMBER 31, 2012 (SPARTAN)

	Light and medium oil and natural gas liquids		Natural gas		BOE[1]	
	Proved (Mbbl)	Proved plus probable (Mbbl)	Proved (Mmcf)	Proved plus probable (Mmcf)	Proved (MBOE)	Proved plus probable (MBOE)
December 31, 2011	12,838.2	18,639.4	11,822	16,750	14,808.5	21,431.1
Extension	966.2	1,628.3	740	1,214	1,089.5	1,830.6
Infill drilling	690.0	1,110.3	390	793	755.0	1,242.5
Improved recovery	-	-	-	-	-	-
Technical revisions	2,027.0	380.1	8,515	9,109	3,446.2	1,898.3
Discoveries	-	-	-	-	-	-
Acquisitions	77.2	98.1	40	51	83.9	106.6
Dispositions	-	-	-	-	-	-
Economic factors	0.2	1.4	(1)	-	-	1.4
Production	(829.5)	(829.8)	(1,054)	(1,054)	(1,005.2)	(1,005.5)
December 31, 2012	**15,769.3**	**21,028.1**	**20,452**	**26,863**	**19,177.9**	**25,505.3**

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2012 (SPARTAN)

	Net present value before income taxes discounted at (% per year)		
($ Millions)	0%	5%	10%
Reserve category:			
PROVED			
Developed producing	428.7	296.9	228.5
Developed non-producing	42.9	29.2	22.3
Undeveloped	437.1	236.2	138.4
TOTAL PROVED	908.7	562.3	389.2
PROBABLE	387.2	149.6	73.1
TOTAL PROVED PLUS PROBABLE	1,295.9	711.9	462.3

PRO FORMA RESERVES AND NET PRESENT VALUES (BONTERRA AND SPARTAN)

SUMMARY OF GROSS OIL AND GAS RESERVES AS OF DECEMBER 31, 2012

Reserve category:	Light and medium oil (Mbbl)	Natural gas (Mmcf)	Natural gas liquids (Mbbl)	BOE[1] (MBOE)
PROVED				
Developed producing	20,435.5	42,799	1,828.5	29,397.2
Developed non-producing	966.5	3,314	89.7	1,608.6
Undeveloped	16,267.0	23,597	1,106.7	21,306.5
TOTAL PROVED	37,669.0	69,710	3,024.9	52,312.2
PROBABLE	12,954.1	25,374	1,041.9	18,225.0
TOTAL PROVED PLUS PROBABLE	50,623.1	95,084	4,066.7	70,537.2

SUMMARY OF NET PRESENT VALUES OF FUTURE NET REVENUE AS OF DECEMBER 31, 2012

	Net present value before income taxes discounted at (% per year)		
($ Millions)	0%	5%	10%
Reserve category:			
PROVED			
Developed producing	1,270.6	839.9	635.0
Developed non-producing	69.7	45.7	33.8
Undeveloped	830.1	427.7	234.6
TOTAL PROVED	2,170.5	1,313.3	903.4
PROBABLE	1,001.8	385.6	191.8
TOTAL PROVED PLUS PROBABLE	3,172.3	1,698.8	1,095.2

FINDING, DEVELOPMENT AND ACQUISITION (FD&A) COSTS

The Company has historically been active in its capital development program. Over three years, Bonterra has incurred the following FD&A[3] costs excluding Future Development Costs:

	2012 FD&A costs per BOE[1][2][3]	2011 FD&A costs per BOE[1][2][3]	2010 FD&A costs per BOE[1][2][3]	Three year average[4]
Proved reserve net additions	$ 13.64	$ 33.22	$ 13.89	$ 16.22
Proved plus probable reserve net additions	$ 16.05	$ 15.38	$ 13.02	$ 14.79

Over three years, Bonterra has incurred the following FD&A(3) costs including Future Development Costs:

	2012 FD&A costs per BOE(1)(2)(3)	2011 FD&A costs per BOE(1)(2)(3)	2010 FD&A costs per BOE(1)(2)(3)	Three year average(5)
Proved reserve net additions	$ 20.91	$ 57.53	$ 21.98	$ 19.47
Proved plus probable reserve net additions	$ 21.62	$ 35.40	$ 19.19	$ 17.92

(1) Barrels of Oil Equivalent may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 MCF: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(2) The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserve additions for that year.

(3) FD&A costs are net of proceeds of disposal and the FD&A costs per BOE are based on reserves acquired net of reserves disposed of.

(4) Three year average is calculated using three year total capital costs and reserve additions on both a Proved and Proved plus Probable basis.

(5) Three year average is calculated using three year total capital costs and reserves additions on both a Proved and Proved plus Probable basis plus the average change in future capital costs over the three year period.

COMMODITY PRICES USED IN THE ABOVE CALCULATIONS OF RESERVES ARE AS FOLLOWS:

	Edmonton par price (Cdn $ per Bbl)	Natural gas AECO-C spot (Cdn $ per MMbtu)	Butanes Edmonton (Cdn $ per Bbl)	Pentanes Edmonton (Cdn $ per Bbl)	Inflation rate (%/Yr)	Exchange rate ($U.S./$Cdn)
2013	84.55	3.31	63.02	90.53	1.5	1.001
2014	89.84	3.72	66.96	96.19	1.5	1.001
2015	88.21	3.91	65.74	94.44	1.5	1.001
2016	95.43	4.70	71.13	102.18	1.5	1.001
2017	96.87	5.32	72.20	103.71	1.5	1.001
2018	98.32	5.40	73.28	105.27	1.5	1.001
2019	99.79	5.49	74.38	106.85	1.5	1.001
2020	101.29	5.58	75.50	108.45	1.5	1.001
2021	104.35	5.67	76.63	110.08	1.5	1.001
2022	105.92	5.76	77.78	111.73	1.5	1.001

Crude oil, natural gas and liquid prices escalate at 1.5 percent thereafter.

PRODUCTION

	2012		
	Oils and NGLs (Bbls per day)	**Natural gas (MCF per day)**	**Total (BOE per day)**
Pembina and Willesden Green, Alberta	**4,170**	**10,634**	**5,942**
Saskatchewan	**199**	**45**	**207**
British Columbia	**27**	**2,179**	**390**
Other Alberta	**115**	**299**	**165**
	4,511	**13,157**	**6,703**

LAND HOLDINGS

Bonterra's holdings of petroleum and natural gas leases and rights are as follows:

	2012		2011	
	Gross acres	**Net acres**	Gross acres	Net acres
Alberta	**186,389**	**109,837**	169,862	107,645
Saskatchewan	**6,585**	**5,416**	6,881	5,630
British Columbia	**62,045**	**22,639**	62,045	22,639
	255,019	**137,892**	238,788	135,914

In 2012, Spartan's holdings of petroleum and natural gas leases and rights are as follows:

	2012	
	Gross acres	**Net acres**
Alberta	**46,987**	**42,043**
Saskatchewan	**80,699**	**56,503**
British Columbia	**-**	**-**
	127,686	**98,546**

PETROLEUM AND NATURAL GAS EXPENDITURES

The following table summarizes petroleum and natural gas capital expenditures incurred by Bonterra on acquisitions, land, seismic, exploration and development drilling and production facilities for the years ended December 31:

($ 000s)	**2012**	2011
Land	**182**	309
Acquisitions	**17,108**	-
Disposals	**(3,753)**	(238)
Exploration and development costs	**84,593**	62,615
Net petroleum and natural gas capital expenditures	**98,130**	62,686

DRILLING HISTORY

The following tables summarize Bonterra's gross and net drilling activity and success:

	2012					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude oil	**34**	**22.9**	**-**	**-**	**34**	**22.9**
Natural gas	**-**	**-**	**-**	**-**	**-**	**-**
Dry	**-**	**-**	**-**	**-**	**-**	**-**
Total	**34**	**22.9**	**-**	**-**	**34**	**22.9**
Success rate	**100%**	**100%**	**-**	**-**	**100%**	**100%**

	2011					
	Development		Exploratory		Total	
	Gross	Net	Gross	Net	Gross	Net
Crude oil	25	17.29	-	-	25	17.29
Natural gas	-	-	-	-	-	-
Dry	-	-	-	-	-	-
Total	25	17.29	-	-	25	17.29
Success rate	100%	100%	-	-	100%	100%

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following report dated March 21, 2013 is a review of the operations and current financial position for the year ended December 31, 2012 for Bonterra Energy Corp. (Bonterra or the Company) and should be read in conjunction with the audited financial statements presented under International Financial Reporting Standards (IFRS), including the notes related thereto.

USE OF NON-IFRS FINANCIAL MEASURES

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

The Company calculates payout ratio by dividing cash dividends paid to shareholders by cash flow from operating activities, both of which are measures prescribed by IFRS which appear on our statements of cash flows. We calculate cash netback by dividing various financial statement items as determined by IFRS by total production for the period on a barrel of oil equivalent basis.

FREQUENTLY RECURRING TERMS

Bonterra uses the following frequently recurring terms in this MD&A: "bbl" refers to barrel, "NGL" refers to natural gas liquids, "MCF" refers to thousand cubic feet 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.

ANNUAL COMPARISONS

As at and for the year ended ($ 000s except $ per share)		**December 31, 2012**	December 31, 2011	December 31, 2010
FINANCIAL				
Revenue – realized oil and gas sales		**142,770**	162,277	118,980
Cash flow from operations		**74,325**	97,409	66,238
Per share – basic		**3.75**	5.04	3.52
Per share – diluted		**3.75**	4.98	3.42
Payout ratio (1)		**83%**	61%	72%
Cash dividends per share (1)		**3.12**	3.06	2.55
Net earnings		**33,211**	43,608	39,954
Per share – basic		**1.68**	2.25	2.12
Per share – diluted		**1.68**	2.23	2.06
Capital expenditures and acquisitions, net of dispositions		**98,130**(2)	62,686	70,680
Total assets		**419,933**	364,176	347,825
Working capital deficiency		**29,876**	51,576	17,905
Long-term debt		**166,808**	69,916	85,386
Shareholders' equity		**163,277**	181,640	190,173
OPERATIONS				
Oil	– barrels per day	**4,035**	4,075	3,585
	– average price ($ per barrel)	**82.04**	92.76	74.76
NGLs	– barrels per day	**476**	386	290
	– average price ($ per barrel)	**52.18**	60.89	47.11
Natural gas	– MCF per day	**13,157**	11,163	10,521
	– average price ($ per MCF)	**2.60**	3.86	4.14
Total barrels of oil equivalent per day (BOE)		**6,703**	6,322	5,628

(1) Cash dividends per share are based on payments made in respect of production months within the quarter.

(2) Includes an acquisition that closed on June 7, 2012 for $17,108,000.

QUARTERLY COMPARISONS

As at and for the periods ended ($ 000s except for $ per share)	2012 Q4	Q3	Q2	Q1
FINANCIAL				
Revenue – realized oil and gas sales	**39,624**	35,204	31,049	36,893
Cash flow from operations	**21,460**	16,440	14,727	21,698
Per share – basic	**1.08**	0.83	0.74	1.10
Per share – diluted	**1.08**	0.83	0.74	1.10
Payout ratio [1]	**72%**	94%	105%	71%
Cash dividends per share [1]	**0.78**	0.78	0.78	0.78
Net earnings	**6,082**	7,746	9,201	10,182
Per share – basic	**0.31**	0.39	0.47	0.52
Per share – diluted	**0.31**	0.39	0.46	0.51
Capital expenditures and acquisitions, net of disposals	**24,069**	27,360	25,288[2]	21,413
Total assets	**419,933**	412,812	393,772	371,757
Working capital deficiency	**29,876**	49,808	42,082	57,889
Long-term debt	**166,808**	128,779	114,747	75,543
Shareholders' equity	**163,277**	169,839	176,292	181,008
OPERATIONS				
Oil (barrels per day)	**4,400**	4,108	3,650	3,975
NGLs (barrels per day)	**595**	461	428	419
Natural gas (MCF per day)	**16,009**	12,583	11,753	12,260
Total BOE per day	**7,663**	6,666	6,037	6,438

(1) Cash dividends per share are based on payments made in respect of production months within the quarter.

(2) Includes an acquisition that closed on June 7, 2012 for $17,108,000.

As at and for the periods ended ($ 000s except for $ per share)	2011 Q4	Q3	Q2	Q1
FINANCIAL				
Revenue – oil and gas sales	**42,818**	36,535	44,754	38,170
Cash flow from operations	**26,180**	21,730	25,465	24,034
Per share – basic	**1.35**	1.12	1.32	1.25
Per share – diluted	**1.33**	1.10	1.29	1.22
Payout ratio (1)	**58%**	69%	59%	58%
Cash dividends per share (1)	**0.78**	0.78	0.78	0.72
Net earnings	**6,067**	9,384	14,533	13,624
Per share – basic	**0.31**	0.49	0.75	0.71
Per share – diluted	**0.31**	0.48	0.74	0.69
Capital expenditures and acquisitions, net of dispositions	**20,529**	15,941	5,872	20,344
Total assets	**364,176**	354,549	348,097	357,000
Working capital deficiency	**51,576**	43,362	30,823	39,777
Long-term debt	**69,916**	72,391	72,608	70,568
Shareholders' equity	**181,640**	185,908	192,297	192,054
OPERATIONS				
Oil (barrels per day)	**4,096**	3,789	4,164	4,258
NGLs (barrels per day)	**493**	340	372	338
Natural gas (MCF per day)	**12,541**	10,553	11,024	10,517
Total BOE per day	**6,679**	5,887	6,373	6,350

(1) Cash dividends per share are based on payments made in respect of production months within the quarter.

BUSINESS ENVIRONMENT

Bonterra's financial results are significantly influenced by fluctuations in commodity prices, including price differentials. The following table depicts selective market benchmark prices and foreign exchange rates in the last eight quarters to assist in understanding volatility in prices and foreign exchange rates that have impacted Bonterra's financial and operating performance.

	Q4-2012	Q3-2012	Q2-2012	Q1-2012	Q4-2011	Q3-2011	Q2-2011	Q1-2011
Crude oil								
WTI (U.S.$/bbl)	**88.18**	92.22	93.49	102.93	94.06	89.76	102.56	94.10
Bonterra average realized price (Cdn$/bbl)	**78.58**	80.54	80.93	88.48	96.25	88.21	101.30	85.02
Natural gas								
AECO (Cdn$/mcf)	**3.20**	2.31	1.89	2.15	3.19	3.65	3.86	3.79
Bonterra average realized price (Cdn$/mcf)	**3.43**	2.41	1.96	2.32	3.34	3.91	4.15	4.12
Foreign exchange (Cdn$/U.S.$)	**0.9913**	0.9948	1.0102	1.0012	1.0231	0.9802	0.9677	0.9860

In 2012, the price differentials between Bonterra's average realized price and WTI widened substantially from prices received in 2011, due in most part to reduced demand because of refinery outages and seasonal turnarounds and the inability to get oil to markets because of pipeline capacity constraints and quality adjustments. The price differential did tighten during the fourth quarter of 2012 due to a combination of increased rail shipments, a reduction in the production of Alberta synthetic crude and increased demand from U.S. and Canadian refineries. However, continued European and North American economic concerns and pipeline capacity constraints negatively affected the price for oil realized in Canada in the latter part of Q4 2012. A number of pipeline expansions and pipeline reversals currently underway will assist in delivering more oil to markets later in 2013 and 2014.

In addition, there are a number of ongoing pipeline initiatives including Keystone XL pipeline in the U.S. and Northern Gateway pipeline in Canada to assist in delivering future increases in Canadian production volumes. However, neither of these have received government or regulatory approval at this time.

Notwithstanding the current price challenges in both oil and natural gas markets, the Company expects to be able to continue exploiting its current land base, growing production on a per share basis and maintaining payment of its dividend.

BUSINESS OVERVIEW, STRATEGY AND KEY PERFORMANCE DRIVERS

Bonterra is a growing petroleum and natural gas focused Canadian energy corporation that actively develops, produces and sells crude oil, natural gas and natural gas liquids, to provide ever increasing returns to its shareholders. Bonterra's geographically concentrated assets are primarily low-risk, high working interest properties that provide abundant infill drilling opportunities and good access to infrastructure and processing facilities. The Company continues to focus its exploration efforts primarily on horizontal infill drilling opportunities for light crude oil in the Company's core Pembina and Willesden Green Cardium properties.

In June 2012, the Company purchased Willesden Green oil and gas assets for consideration of $17,108,000. The purchase added 52.3 gross (10.5 net) sections of land, 191 gross (37 net) potential Cardium formation drilling locations and 250 BOE per day of production, net to the Company. These lands are considered underdeveloped as horizontal well development is in its early stages.

On January 25, 2013, Bonterra acquired 100 percent of the issued and outstanding common shares of Spartan Oil Corp. (Spartan) pursuant to an arrangement agreement. Spartan was a public oil and gas company with properties in Alberta and Saskatchewan. Consideration for Spartan shares was 0.1169 voting common shares of Bonterra, which amounted to the issuance of 10,711,405 Bonterra shares valued at $502,258,000. Spartan has contributed strong cash flow, positive working capital, no debt and a light-oil asset base primarily concentrated in the Pembina Cardium region, providing a complimentary production base and a long-term inventory of drilling opportunities. The acquisition is anticipated to assist Bonterra on a financial and operating basis, continue to grow production and cash flow on a per share basis and to maintain a strong financial position. The acquisition adds to Bonterra's sustainable, high-netback, production profile, company-owned infrastructure and its high-quality, multi-year drilling inventory that is in excess of 10 years (assuming four wells per section). On March 1, 2013 Spartan amalgamated with Bonterra.

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

DRILLING

	Three months ended						Year ended			
($ 000s)	**December 31, 2012**		September 30, 2012		December 31, 2011		**December 31, 2012**		December 31, 2011	
	Gross(1)	**Net**(2)	Gross(1)	Net(2)	Gross(1)	Net(2)	**Gross**(1)	**Net**(2)	Gross(1)	Net(2)
Crude oil horizontal – operated	**6**	**4.6**	10	7.8	6	5.2	**24**	**20.0**	20	16.3
Crude oil horizontal – non-operated	**6**	**1.6**	2	1.0	2	0.6	**10**	**2.9**	5	1.0
Total	**12**	**6.2**	12	8.8	8	5.8	**34**	**22.9**	25	17.3
Success rate		**100%**		100%		100%		**100%**		100%

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

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

During 2012, the Company placed two gross (two net) wells on production that were drilled in 2011, drilled 24 gross (20.0 net) wells, of which 21 gross (17.0 net) were placed on production. The remaining three (3.0 net) wells were placed on production in the first quarter of 2013. In addition, 10 gross (2.9 net) non-operated wells were drilled and placed on production during 2012.

The majority of the Company's 2012 drilling program was completed in the third quarter of 2012. Of the eight gross wells drilled in the first half of 2012, five gross (4.6 net) were completed and placed on production in the third quarter.

In the second half of the year, the Company drilled 16 gross (12.4 net) wells of which nine gross (7.0 net) were placed on production in the third quarter and four gross (2.4 net) were placed on production in the fourth quarter. Included in the fourth quarter were three gross (3.0 net) wells drilled but originally budgeted for 2013. These wells commenced production in the first quarter of 2013.

PRODUCTION

	Three months ended			Year ended	
($ 000s)	**December 31, 2012**	September 30, 2012	December 31, 2011	**December 31, 2012**	December 31, 2011
Crude oil (barrels per day)	**4,400**	4,108	4,096	**4,035**	4,075
NGLs (barrels per day)	**595**	461	493	**476**	386
Natural gas (MCF per day)	**16,009**	12,583	12,541	**13,157**	11,163
Average BOE per day	**7,663**	6,666	6,679	**6,703**	6,322

Production volumes during 2012 increased to 6,703 BOE per day compared to 6,322 BOE per day during 2011. The increase in production is due to the continued success of the Cardium horizontal drilling program in the Pembina and Willesden Green areas and the accelerated drilling program in the second half of the year. During 2012, the increase in production was negatively impacted by pipeline constraints, a saturated refining market, forest fires and high levels of precipitation during Q2 2012 which significantly delayed drilling and completion of wells.

Production volumes for Q4 2012 increased by 15 percent to 7,663 BOE per day compared to Q3 2012, which was due to a full quarter of production from newly tied-in wells. The Company tied-in four gross wells (2.4 net) in Q4 2012 compared to 14 gross wells (11.6 net) late in Q3 2012. The increased production was partially offset by a pipeline apportionment for the month of December.

Subsequent to year end, the Company purchased Spartan. At the time of closing, Bonterra was producing approximately 8,700 BOE per day and Spartan was producing approximately 4,800 BOE per day for a combined production of 13,500 BOE per day that includes substantial flush production from a large number of new wells. These new wells have sizeable decline rates during the first year of production and as such, average daily production volumes for 2013 are estimated to be approximately 12,000 BOE per day (a reduction from the present level of 13,500 BOE per day). Spartan's assets also consisted of a 12 MMcf per day operated and wholly owned gas plant that will provide more flexibility for gas processing, help alleviate pipeline constraints and reduce future shut-in production issues.

OIL AND GAS SALES

	Three months ended			Year ended	
($ 000s)	**December 31, 2012**	September 30, 2012	December 31, 2011	**December 31, 2012**	December 31, 2011
Revenue – oil and gas sales	**39,624**	35,204	42,818	**142,770**	162,277
Average realized prices ($):					
Crude oil (per barrel)	**78.58**	80.54	96.25	**82.04**	92.76
NGLs (per barrel)	**50.41**	46.40	59.46	**52.18**	60.89
Natural gas (per MCF)	**3.43**	2.41	3.34	**2.60**	3.86
Average (per BOE)	**56.20**	57.40	69.68	**58.19**	70.33

Revenue from oil and gas sales decreased by $19,507,000 in 2012 or 12 percent compared to 2011. This decrease was due to an 11 percent decrease in the average realized price per BOE, made up of a combination of an 11 percent decrease in oil prices, a 14 percent decrease in NGL prices and 32 percent decrease in natural gas prices from one year ago. Overall pricing was the significant factor in reduced revenues as oil production was relatively flat, natural gas production increased by 18 percent and NGL production increased by 23 percent compared to 2011.

The quarter over quarter increase in oil and gas revenues of 13 percent or $4,420,000, was in part due to a 15 percent increase in production, being a combination of oil production increases of seven percent, NGL production increases of 29 percent and natural gas production increases of 27 percent compared to the prior quarter. Average realized prices were also a factor in increased revenues, as NGL prices increased nine percent and natural gas prices increased by 42 percent compared to the prior quarter.

The Company's product split on a revenue basis for the 2012 is approximately 91 percent weighted towards crude oil and NGLs. This ratio will likely remain similar or increase as the Company continues to develop its Pembina and Willesden Green Cardium (mainly oil) properties.

The Company did not enter into any commodity price hedges or other types of risk management contracts in either 2011 or 2012.

ROYALTIES

	Three months ended			Year ended	
($ 000s)	**December 31, 2012**	September 30, 2012	December 31, 2011	**December 31, 2012**	December 31, 2011
Crown royalties	**2,436**	1,942	2,993	**9,727**	12,316
Freehold, gross overriding and other royalties	**1,017**	720	1,277	**4,033**	5,261
Total royalties	**3,453**	2,662	4,270	**13,760**	17,577
Crown royalties – percentage of revenue	**6.1**	5.5	7.6	**6.8**	7.6
Freehold, gross overriding and other royalties – percentage of revenue	**2.6**	2.1	2.4	**2.8**	3.2
Royalties – percentage of revenue	**8.7**	7.6	10.0	**9.6**	10.8
Royalties $ per BOE	**4.90**	4.34	6.95	**5.61**	7.62

Royalties paid by the Company consist primarily of Crown royalties paid to the Provinces of Alberta, Saskatchewan and British Columbia. The Company's average Crown royalty rate is approximately 6.8 percent for 2012 compared to 7.6 percent for 2011. The decrease is primarily due to lower commodity prices for crude oil and natural gas attracting lower crown royalty rates, partially offset by horizontal Cardium wells no longer being eligible for the initial five percent royalty rate due to accumulated production thresholds being reached or the expiry of time allowed to reach the threshold levels. A significant portion of the Company's production is from low productivity wells and therefore have reduced Crown royalty rates.

The Crown royalty rate increased for Q4 2012 compared to Q3 2012 primarily due to increased volumes and prices for natural gas and NGLs.

Non-crown royalties decreased for 2012 compared to 2011 primarily due to less oil and gas revenue from wells subject to non-crown royalties as most new wells were drilled on crown lands. The percent increase in non-crown royalties quarter over quarter is primarily due to increased production from the new wells subject to freehold royalties that were placed on production in the latter half of the year.

PRODUCTION COSTS

	Three months ended			Year ended	
($ 000s except $ per BOE)	**December 31, 2012**	September 30, 2012	December 31, 2011	**December 31, 2012**	December 31, 2011
Production costs	**13,407**	10,178	9,824	**41,408**	36,787
$ per BOE	**19.02**	16.59	15.99	**16.88**	15.94

Total production costs for 2012 increased 13 percent from 2011. On a per BOE basis, production costs have increased by six percent.

In 2012, production costs increased due to higher costs associated with gas compression, gathering and processing fees. The Company also experienced higher road maintenance costs due to extended wet weather in Q2 2012 and increased frequency of plant turnarounds during year. In addition, the Company received third party equalization charges of approximately $1,650,000 in the fourth quarter. These onetime charges had the effect of increasing production costs by $0.67 per BOE in 2012. In addition, the Company was unable to tie-in a portion of its natural gas production due to pipeline constraints, thereby increasing costs on a per BOE basis.

Production costs increased by $3,229,000 in Q4 2012 compared to Q3 2012, due to a 15 percent increase in production, including a 38 percent increase in natural gas production. The Company experienced higher gas compression, gathering, processing fees and operating charges. Also included in the production costs were onetime charges from third parties. These charges increased production costs by $2.24 per BOE in Q4 2012.

With the acquisition of Spartan's wholly owned gas plant facility, the Company now has access to alternative lower cost facilities for its gas processing. This facility will help to increase gas processing capacity which should alleviate production apportionments and reduce production costs on a per BOE basis in 2013.

OTHER INCOME

	Three months ended			Year ended	
($ 000s)	**December 31, 2012**	September 30, 2012	December 31, 2011	**December 31, 2012**	December 31, 2011
Gain on sale of property	**-**	7	-	**3,616**	162
Realized gain on investments	**943**	1,317	-	**2,705**	2,126
Investment income	**39**	50	5	**161**	27
Administrative income	**37**	83	79	**285**	327
	1,019	1,457	84	**6,767**	2,642

During 2012, the Company disposed of a portion of its Central Alberta Redwater property for cash proceeds of $1,109,000, equal to the accounting gain, as this property was recorded with no carrying value. The Company also disposed of a portion of its Central Alberta Tomahawk property for cash proceeds of $2,500,000. At the time of disposition, the property had no carrying value which results in a gain on sale equal to its proceeds. The Company maintained a non-operated 50 percent working interest in the Tomahawk property. One new well was drilled and placed on production in the third quarter and three more wells were drilled and placed on production in the fourth quarter of 2012.

During 2012, the Company disposed of a portion of its investments for gross proceeds of $3,485,000 (December 31, 2011 - $3,991,000). In addition, the Company realized a gain on investments of $631,000 on the share exchange between Pine Cliff Energy Ltd. and Geomark Exploration Ltd. (see related party section). The market value of the investments held by the Company is in excess of $5,000,000 at December 31, 2012 (December 31, 2011 - $6,800,000). The decrease in carrying value is mainly due to the sale of investments in 2012 partially offset by increased market value in the remaining investments.

The Company receives administrative income by way of management fees from related parties (see related party transactions).

GENERAL AND ADMINISTRATION (G&A) EXPENSE

	Three months ended			Year ended	
($ 000s except $ per BOE)	**December 31, 2012**	September 30, 2012	December 31, 2011	**December 31, 2012**	December 31, 2011
Employee compensation expense	**875**	935	896	**3,974**	4,456
Office and administration expense	**755**	600	1,059	**2,121**	2,332
	1,630	1,535	1,955	**6,095**	6,788
$ per BOE	**2.31**	2.50	3.18	**2.48**	2.94

Total G&A expense decreased 10 percent to $6,095,000 for the year ended December 31, 2012 from $6,788,000 in 2011.

The decrease in employee compensation expense of $482,000 for 2012 compared to a year ago was primarily due to reduced number of staff and a decrease in accrued bonuses, due to lower net earnings before income taxes. The Company has a bonus plan in which the bonus pool consists of three percent of earnings before income taxes. The Company firmly believes that tying employee compensation (including the use of stock options) to the performance of the Company clearly aligns the interest of the employees to that of the shareholders.

Quarter over quarter employee compensation expense decreased due to a reduction in accrued bonuses related to decreased earnings before taxes.

The decrease in office and administration expense for 2012, related primarily to a decrease in costs of legal, engineering and regulatory filing fees. This was partially offset by increased consulting fees and computer software costs compared to 2011.

Quarter over quarter office and administration expense increased by $155,000 due to increases in office rent, computer software costs and additional bank fees relating to the increase in the credit facility during the fourth quarter of 2012.

FINANCE COSTS

	Three months ended			Year ended	
($ 000s except $ per BOE)	**December 31, 2012**	September 30, 2012	December 31, 2011	**December 31, 2012**	December 31, 2011
Interest on long-term debt	**1,616**	779	547	**3,730**	2,272
Other interest	**225**	305	305	**1,279**	1,210
Interest expense	**1,841**	1,084	852	**5,009**	3,482
$ per BOE	**2.61**	1.77	1.39	**2.04**	1.51
Unwinding of the discounted value of decommissioning liabilities	**224**	227	339	**886**	954
Total finance costs	**2,065**	1,311	1,191	**5,895**	4,436

Interest on long-term debt increased 64 percent in 2012 compared to 2011 as the Company increased the bank debt in the second quarter of 2012 with the Willesden Green Asset acquisition for cash of $17,108,000, repaid a $20,000,000 related party loan in the fourth quarter of 2012, increased the capital drilling program compared to 2011 and experienced decreased cash flows as a result of lower commodity pricing from one year ago.

Other interest relates to amounts paid to related parties (see related party transactions), a $15,000,000 subordinated promissory note from a private investor and a onetime interest charge of $145,000 for the period between the effective date of March 1, 2012 and the closing date of June 7, 2012 on the Willesden Green oil and gas asset purchase.

SHARE-BASED PAYMENTS

($ 000s)	Three months ended December 31, 2012	September 30, 2012	December 31, 2011	Year ended December 31, 2012	December 31, 2011
$ per BOE	**1,264**	1,040	822	**4,241**	2,554

Share-based payments are a statistically calculated value representing the estimated expense of issuing employee stock options. The Company records a compensation expense over the vesting period based on the fair value of options granted to employees, directors and consultants. Share-based payments increased in 2012 over 2011 primarily due to the issuance of 496,500 options issued in the fourth quarter of 2011 and 942,000 options that were issued during 2012. Quarter over quarter share-based payments increased as 734,000 of the 942,000 options issued in 2012 were issued during the fourth quarter of 2012.

Based on currently outstanding options, the Company anticipates that an expense of approximately $3,785,000 will be recorded for 2013, $427,000 for 2014 and $107,000 for 2015. For more information about options issued and outstanding, please refer to Note 15 of the December 31, 2012 audited annual financial statements.

DEPLETION, DEPRECIATION AND IMPAIRMENT

($ 000s)	Three months ended December 31, 2012	September 30, 2012	December 31, 2011	Year ended December 31, 2012	December 31, 2011
Depletion and depreciation	**10,585**	8,010	13,467	**33,521**	32,699
Impairment of natural gas assets	**-**	-	2,585	**-**	2,585

Capital costs for oil and gas properties that result in the addition of reserves are depleted using the unit-of-production basis by field over their total developed reserve life which includes proved plus probable developed reserves only. In 2012, the Company adjusted its estimate from using a proved developed reserve base to total developed reserve base to better reflect the asset life expectancy of the Company's Pembina and Willesden Green Cardium properties through the application of the horizontal drilling program.

For production facility and equipment expenditures such as well and production processing equipment, the Company uses a 10 percent declining basis for depreciation calculation.

Provision for depletion and depreciation increased by approximately three percent for 2012 over 2011. The increase in depletion was the result of increased production volumes in 2012 of six percent partially offset by an eight percent increase in total developed reserves.

Depletion and depreciation increased by 32 percent in the fourth quarter of 2012 over the prior quarter. This was primarily attributable to increased production of 15 percent and additional capital costs being subject to depletion as the majority of the 2012 wells drilled were placed on production in the second half of the year.

There were no impairment provisions recorded for the year ended December 31, 2012. In 2011, there were significant reductions in the future commodity price forecasts for natural gas used by the Company's independent reserves evaluator when compared to the previous year resulting in an impairment provision of $2,585,000 for minor natural gas assets in British Columbia.

TAXES

The Company recorded a deferred tax expense of $11,406,000 for 2012 (2011 - $17,885,000). The deferred tax expense decrease in 2012 compared to 2011 is primarily related to decreased earnings before income taxes.

The Company has $424,101,000 of tax pools, which may be used to reduce taxable income in future years, limited to various rates of utilization. The Company also has $27,670,000 (December 31, 2011 - $27,670,000) remaining of investment tax credits that expire between the years 2019 to 2028. In addition, the Company has $135,502,000 (December 31, 2011 - $137,289,000) of capital loss carry forwards which can only be claimed against taxable capital gains. For additional information regarding income taxes, see Note 9 of the December 31, 2012 audited annual financial statements.

NET EARNINGS

	Three months ended			Year ended	
($ 000s except $ per share)	**December 31, 2012**	September 30, 2012	December 31, 2011	**December 31, 2012**	December 31, 2011
Net earnings	**6,082**	7,746	6,067	**33,211**	43,608
$ per share – basic	**0.31**	0.39	0.31	**1.68**	2.25
$ per share – diluted	**0.31**	0.39	0.31	**1.68**	2.23

Net earnings decreased in 2012 by $10,397,000 or 24 percent from 2011. Decreased net earnings resulted primarily from lower crude oil and natural gas prices, along with increases to operating costs, finance costs and share-based payments expense. This decrease was partially offset by increased natural gas and NGL production and a gain on sale of assets along with decreased royalties and deferred tax expense.

The decrease in net earnings for Q4 2012 compared to Q3 2012 resulted from increased operating costs, royalties, finance costs and depletion and depreciation expense in Q4 2012 and a larger gain on sale of a portion of the Company's investment in marketable securities recorded in Q3 2012.

OTHER COMPREHENSIVE INCOME

Other comprehensive loss for 2012 consists of an unrealized gain before tax on investments (including investments in a related party) of $1,514,000 relating to an increase in the investments' fair value (December 31, 2011 – unrealized loss of $1,462,000 relating to a decrease in the investments' fair value). The Company also disposed of a portion of these investments in 2012 for a realized gain before tax of $2,705,000 (December 31, 2011 - $2,126,000). Realized gains decrease other comprehensive income as these gains are transferred to net 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 related party, net of tax.

CASH FLOW FROM OPERATIONS

	Three months ended			Year ended	
($ 000s except $ per share)	**December 31, 2012**	September 30, 2012	December 31, 2011	**December 31, 2012**	December 31, 2011
Cash flow from operations	**21,460**	16,440	26,180	**74,325**	97,409
$ per share – basic	**1.08**	0.83	1.35	**3.75**	5.04
$ per share – diluted	**1.08**	0.83	1.33	**3.75**	4.98

In 2012, cash flow from operations decreased by $23,084,000 or 24 percent compared to 2011. This was primarily due to decreased crude oil and natural gas prices along with increases in operating and finance costs, partially offset by lower royalties and G&A expenditures. The quarter over quarter increase of $5,020,000, or 31 percent, was due primarily to an increase in oil and gas production and revenue, partially offset by higher operating and finance costs and royalties.

CASH NETBACK

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

	Three months ended			Year ended	
$ per BOE	**December 31, 2012**	September 30, 2012	December 31, 2011	**December 31, 2012**	December 31, 2011
Production volumes (BOE)	**705,001**	613,296	614,482	**2,453,474**	2,307,465
Gross production revenue	**$56.20**	$57.40	$69.68	**$58.19**	$70.33
Royalties	**(4.90)**	(4.34)	(6.95)	**(5.61)**	(7.62)
Field operating costs	**(19.02)**	(16.59)	(15.99)	**(16.88)**	(15.94)
Field netback	**32.28**	36.47	46.74	**35.70**	46.77
General and administrative	**(2.31)**	(2.50)	(3.18)	**(2.48)**	(2.94)
Interest and other	**(2.51)**	(1.56)	(1.25)	**(1.86)**	(1.36)
Cash netback	**$27.46**	$32.41	$42.31	**$31.36**	$42.47

RELATED PARTY TRANSACTIONS

On October 19, 2012, Pine Cliff Energy Ltd. (Pine Cliff), a company with some common directors and some common management with Bonterra, acquired 100 percent of the issued and outstanding common shares of Geomark Exploration Ltd. (Geomark), pursuant to an arrangement agreement. Consideration for each Geomark Share was 1.5 voting common shares of Pine Cliff. Bonterra now holds 1,034,523 common shares in Pine Cliff (December 31, 2011 – 689,682 common shares in Geomark) which represents 0.7 percent ownership in Pine Cliff's outstanding common shares. Pine Cliff's common shares have a fair market value as of December 31, 2012 of $910,000 (December 31, 2011 - $566,000 fair value of the Geomark shares). Geomark paid a management fee to the Company of $225,000 (December 31, 2011 - $270,000). With the arrangement, the management agreement between Bonterra and Geomark was terminated effective October 19, 2012.

On November 9, 2012, Bonterra repaid the $20,000,000 (December 31, 2011 - $20,000,000) loan with Geomark. Interest paid on this loan during the year was $397,000 (December 31, 2011 - $475,000).

The Company also has a management agreement with Pine Cliff. Pine Cliff paid a management fee to the Company of $60,000 (December 31, 2011 - $60,000). Services provided by the Company include executive services, accounting services, oil and gas administration and office administration. All services performed are charged at estimated fair value. As at December 31, 2012, the Company had an account receivable from Pine Cliff of $45,000 (December 31, 2011 – $4,000).

As at December 31, 2012, the Company's CEO, Chairman of the Board and major shareholder has loaned the Company $12,000,000 (December 31, 2011 - $12,000,000). The loan bears interest at Canadian chartered bank prime less 5/8th of a percent and has no set repayment terms but is payable on demand. Security under the debenture is over all of the Company's assets and is subordinated to any and all claims in favour of the syndicate of senior lenders providing credit facilities to the Company. The loan can only be repaid should the Company have sufficient available borrowing limits under the Company's credit facility. Interest paid on this loan during 2012 was $286,000 (December 31, 2011 - $285,000). This loan results in a substantial benefit to Bonterra as the interest paid to the CEO by Bonterra is lower than bank interest.

LIQUIDITY AND CAPITAL RESOURCES

WORKING CAPITAL DEFICIENCY

($ 000s)	**December 31, 2012**	December 31, 2011
Working capital deficiency	**29,876**	51,576
Long-term bank debt	**166,808**	69,916
Net debt	**196,684**	121,492
Shareholders' equity	**163,277**	181,640
Total	**359,961**	303,132

NET DEBT AND WORKING CAPITAL

Net debt is a combination of long-term bank debt and working capital. The increase in net debt from $121,492,000 at December 31, 2011 to $196,684,000 at December 31, 2012 is attributable primarily to the substantial decrease in commodity prices in 2012 compared to 2011 and thus lower field net backs and cash flow from operations. In addition, the Company increased capital spending during 2012 compared to 2011, while at the same time maintaining the dividends paid to shareholders.

Working capital is calculated as current liabilities less current assets. The Company finances its working capital deficiency using cash flow from operations, its long-term bank facility, share issuances, option exercises and sale of investments.

CAPITAL EXPENDITURES

During the year ended December 31, 2012, the Company incurred capital costs of $81,022,000 (2011 - $62,686,000 net of drilling credits) net of proceeds on disposal of property, plant and equipment. The costs relate primarily to the drilling of 24 gross (20.0 net) Pembina and Willesden Green Cardium operated horizontal wells and 10 (2.9 net) non-operated wells, facilities and gathering systems.

In June 2012, the Company purchased Willesden Green oil and gas assets for cash consideration of $17,108,000, which included oil and gas properties and equipment and is not included in the above outlined capital costs for 2012.

LONG-TERM DEBT

Long-term debt represents the outstanding draws from the Company's credit facility as described in the notes to the Company's annual financial statements. As of December 31, 2012, the Company has a bank facility consisting of a $160,000,000 (December 31, 2011 - $120,000,000) syndicated revolving credit facility and a $20,000,000 non-syndicated revolving credit facility. Amounts drawn under these facilities at December 31, 2012 were $166,808,000 (December 31, 2011 - $69,916,000). The interest rates on the outstanding debt as of December 31, 2012 were 3.8 percent and 3.0 percent on the Company's Canadian prime rate loan and Banker's Acceptances, respectively. The loan is revolving to April 25, 2013 and with a maturity date of April 25, 2014 and is subject to annual review. The revolving credit facility has no fixed terms of repayment.

Advances drawn under the credit facility are secured by a fixed and floating charge debenture over the assets of the Company. In the event the credit facility are 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 please see Note 13 of the December 31, 2012 audited annual financial statements.

SHAREHOLDERS' EQUITY

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

	December 31, 2012		December 31, 2012	
Issued and fully paid – common shares	**Number**	**Amount ($ 000s)**	Number	Amount ($ 000s)
Balance, beginning of year	**19,571,316**	**142,567**	19,219,541	135,030
Issued pursuant to the Company share option plan	**338,225**	**6,934**	351,775	7,150
Transfer from contributed surplus to share capital		**376**		387
Balance, end of year	**19,909,541**	**149,877**	19,571,316	142,567

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 Company provides a stock option plan for its directors, officers, employees and consultants. Under the plan, the Company may grant options for up to 1,990,954 (December 31, 2011 – 1,957,131) 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, please see Note 15 of the December 31, 2012 audited annual financial statements.

DIVIDEND POLICY

For the year ended December 31, 2012, Bonterra paid dividends of $61,707,000 ($3.12 per share) compared to $58,805,000 ($3.04 per share) in the same period in 2011. Bonterra's dividend policy is regularly monitored and is dependent upon production, commodity prices, funds from operations, debt levels and capital expenditures. With its large inventory of undrilled locations, Bonterra continues to be well positioned to provide its shareholders a combination of sustainable growth and dividend income.

Bonterra's dividends to its shareholders are funded by cash flow from operating activities with the remaining cash flow directed towards capital spending and, where applicable, the repayment of debt. To the extent that the excess cash flow from operations after dividends is not sufficient to cover capital spending, the shortfall is funded by funds from the exercising of employee stock options, the sale of investments and by draw downs from Bonterra's credit facilities. Bonterra intends to provide dividends to shareholders that are sustainable to the Company considering its liquidity and its long-term operational strategy. In addition, since the level of dividends is highly dependent upon cash flow generated from operations, which fluctuates significantly in relation to changes in financial and operational performance, commodity prices, interest and exchange rates and many other factors, future dividends cannot be assured. Bonterra's payout ratio based on cash flow was 83 percent for the year ended December 31, 2012 (61 percent for the year ended December 31, 2011).

NET DEBT TO CASH FLOW

Bonterra intends to continue focusing on managing its cash flow, capital expenditure ranges and dividend payments. At December 31, 2012, the Company was in excess of its annual guidance of 1.5 to 1 times net debt to cash flow ratio with a ratio of 2.65 to 1 times. This ratio was higher due to lower than budgeted commodity prices, higher than budgeted capital costs and the Willesden Green oil and gas asset acquisition of $17.1 million. The Company believes the Spartan acquisition in January 2013 (see Note 20 to the annual financial statements) and the Willesden Green asset acquisition will help to sustain future cash flows and shareholder dividends and significantly improve the debt to cash flow ratio back to an annual range of 1.0 to 1 times and 1.5 to 1 times.

QUARTERLY FINANCIAL INFORMATION

	2012			
For the periods ended ($ 000s except $ per share)	**Q4**	Q3	Q2	Q1
Revenue – oil and gas sales	**39,624**	35,204	31,049	36,893
Cash flow from operations	**21,460**	16,440	14,727	21,698
Net earnings	**6,082**	7,746	9,201	10,182
Per share – basic	**0.31**	0.39	0.47	0.52
Per share – diluted	**0.31**	0.39	0.46	0.51

	2011			
For the periods ended ($ 000s except $ per share)	Q4	Q3	Q2	Q1
Revenue – oil and gas sales	42,818	36,535	44,754	38,170
Cash flow from operations	26,180	21,730	25,465	24,034
Net earnings	6,067	9,384	14,533	13,624
Per share – basic	0.31	0.49	0.75	0.71
Per share – diluted	0.31	0.48	0.74	0.69

The fluctuations in the Company's revenue and net earnings from quarter to quarter are primarily caused by variations in production volumes, realized oil and natural gas pricing and the related impact on royalties. Q4 2011 net earnings were lower than the prior quarter due to the recording of an impairment of natural gas assets.

CRITICAL ACCOUNTING ESTIMATES

The historical information in this MD&A is based primarily on the Company's financial statements, which have been prepared in Canadian dollars in accordance with IFRS. The application of IFRS requires management to make estimates, judgements and assumptions that affect the reported amounts of assets and liabilities and the disclosure of contingent assets or liabilities, if any, at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Bonterra bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances. Actual results could differ materially from these estimates under different assumptions or conditions. The following are estimates and judgements applied by management that most significantly affect the company's financial statements:

RESERVE ESTIMATION

The capitalized costs of proved oil and gas properties are amortized to expense on a unit of production basis at a rate calculated by reference to proved plus probable developed reserves determined in accordance with National Instrument 51-101 and the Canadian Oil and Gas Evaluation Handbook. Commercial reserves are determined using best estimates of oil and gas in place, recovery factors, future development and extraction cots and future oil and gas prices.

Proved reserves are those reserves that have a reasonable certainty (normally at least 90 percent confidence) of being recoverable under existing economic and political conditions, with existing technology. Probable reserves are based on geological and/or engineering data similar to that used in estimates of proved reserves, but technical, contractual, or regulatory uncertainties preclude such reserves from being classified as proved. Probable reserves are attributed to known accumulations that have a greater or equal to 50 percent confidence level of recovery.

EXPLORATION AND EVALUATION EXPENDITURES

Exploration and evaluation costs are initially capitalized with the intent to establish commercially viable reserves. Exploration and evaluation assets include undeveloped land costs, licenses and exploration well costs. Exploration costs related to geophysical and geological activities are immediately charged to earnings as incurred. The Company is required to make estimates and judgments about future events and circumstances regarding the economic viability of extracting the underlying resources. The costs are subject to technical, commercial and management review to confirm the continued intent to develop and extract the underlying resources. Changes to project economics, resource quantities, expected production techniques, unsuccessful drilling, expired mineral leases, production costs and required capital expenditures are important factors when making this determination. To the extent a judgment is made that extraction of the reserves is not viable, the exploration and evaluation costs will be impaired and charged to net earnings.

IMPAIRMENT OF NON-FINANCIAL ASSETS

The recoverable amounts of Bonterra's cash-generating units and individual assets have been determined based on fair values less costs to sell. This calculation requires the use of estimates and assumptions. Oil and gas prices and other assumptions will change in the future, which may impact Bonterra's recoverable amount calculated and may therefore require a material adjustment to the carrying value of property and plant and equipment. Bonterra monitors internal and external indicators of impairment relating to its exploration and evaluation assets and property, plant and equipment.

Impairment is evaluated at the cash-generating unit (CGU) level. The determination of CGUs requires judgment in defining the smallest identifiable group of assets that generate cash inflows that are largely independent of the cash inflows from other assets or groups of assets. CGUs have been determined based on similar geological structure, shared infrastructure, geographical proximity, commodity type and similar exposures to market risks.

DECOMMISSIONING AND RESTORATION COSTS

Decommissioning and restoration costs will be incurred by Bonterra at the end of the operating lives of Bonterra's oil and gas properties. The ultimate decommissioning and restoration costs are uncertain and cost estimates can vary in response to many factors including assumptions of inflation, present value discount rates on future liabilities, changes to relevant legal requirements and the emergence of new restoration techniques or experience at other production sites. The expected timing and amount of expenditures can also change, for example, in response to changes in reserves or changes in laws and regulations or their interpretation.

SHARE-BASED PAYMENTS

The Company accounts for share-based payments using the fair-value method of accounting for stock options granted to directors, officers, employees and other service providers using the Black-Scholes option pricing model. Estimating fair value requires the determination of the most appropriate valuation model for a grant of equity instruments, which is dependent on the terms and conditions of the grant. This also requires the determination of the most appropriate inputs to the valuation model including the expected life of the option, risk free interest rates, volatility and dividend yield and making assumptions about them.

DEFERRED INCOME TAXES

Deferred income tax is recognized using the liability method, providing for unused tax losses, unused tax credits and temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized for the following temporary differences: the initial recognition of assets and liabilities in a transaction that is not a business combination and that affects neither accounting nor taxable profit, and differences relating to investments in subsidiaries to the extent that they are unlikely to be reversed in the foreseeable future. Deferred tax is measured at the tax rates that are expected to be applied to the temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date.

Bonterra recognizes the net future tax benefit related to deferred income tax assets to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future. Assessing the recoverability of deferred income tax assets requires Bonterra to make significant estimates related to expectations of future taxable income. Estimates of future taxable income are based on forecasted cash flows from operations and Bonterra's interpretation of the application of existing tax laws. To the extent that any interpretation of tax law is challenged by the tax authorities or future cash flows and taxable income differ significantly from estimates, the ability of Bonterra to realize the net deferred tax assets recorded at the balance sheet date may be compromised.

FINANCIAL INSTRUMENTS

The estimated fair values of financial assets and liabilities, by their very nature, are subject to measurement uncertainty due to their exposure to credit, liquidity and market risks. Furthermore, the Company may use derivative instruments to manage commodity price, foreign currency and interest rate exposures. The fair values of these derivatives are determined using valuation models which require assumptions concerning the amount and timing of future cash flows and discount rates. Management's assumptions rely on external observable market data including quoted commodity prices and volatility, interest rate yield curves and foreign exchange rates. The resulting fair value estimates may not be indicative of the amounts realized or settled in current market transactions and as such are subject to measurement uncertainty.

FORWARD-LOOKING INFORMATION

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

All such forward-looking information is based on certain assumptions and analyses made by us in light of our experience and perception of historical trends, current conditions and expected future developments, as well as other factors we believe are appropriate in the circumstances. The risks, uncertainties, and assumptions are difficult to predict and may affect operations, and may include, without limitation: foreign exchange fluctuations; equipment and labour shortages and inflationary costs; general economic conditions; industry conditions; changes in applicable environmental, taxation and other laws and regulations as well as how such laws and regulations are interpreted and enforced; the ability of oil and natural gas companies to raise capital; the effect of weather conditions on operations and facilities; the existence of operating risks; volatility of oil and natural gas prices; oil and gas product supply and demand; risks inherent in the ability to generate sufficient cash flow from operations to meet current and future obligations; increased competition; stock market volatility; opportunities available to or pursued by us; and other factors, many of which are beyond our control.

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 there from. 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.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures have been designed to ensure the information required to be disclosed by the Company is accumulated and communicated to the Company's management, as appropriate, to allow timely decisions regarding required disclosures. The Company's Chief Executive Officer (CEO) and Chief Financial Officer (CFO), together with management, have concluded, based on their evaluation as of December 31, 2012 that the Company's disclosure controls and procedures are effective to provide reasonable assurance that material information related to the issuer, is made known to them by others within the Company. It should be noted that while the Company's CEO and CFO believe that the Company's disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system, no matter how well conceived or operated, can provide only reasonable, not absolute, assurance that the objective of the control system is met.

INTERNAL CONTROL UPDATE

The Company's CEO and CFO are responsible for establishing and maintaining Disclosure Controls and Procedures (DC&P) and adequate Internal Control over Financial Reporting (ICFR) to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements at December 31, 2012 for external purposes in accordance with International Financial Reporting Standards. The control framework the Company used to design its ICFR was in accordance with the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's CEO and CFO have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Company's internal control over financial reporting at December 31, 2012 of the Company and concluded that the Company's internal control over financial reporting are effective for the foregoing purpose.

No changes were made to the Company's internal control over financial reporting during the year ended December 31, 2012, that have materially affected, or are reasonably likely to materially affect, the internal control over financial reporting.

All internal control systems, no matter how well designed, have inherent limitations. These systems, therefore, provide reasonable but not absolute assurance that financial information is accurate and complete.

FINANCIAL REPORTING UPDATE

As of January 1, 2013, Bonterra will be required to adopt amendments to IAS 1 "Presentation of Financial Statements" which will require companies to group together items within other comprehensive income that may be reclassified to the net earnings section of the comprehensive income statement. Bonterra does not expect a material impact as a result of the amendments.

Each of the additional new standards outlined below is effective for annual periods beginning on or after January 1, 2013 with early adoption permitted, except for IFRS 9 "Financial Instruments" which is effective for annual periods beginning on or after January 1, 2015. The Company has not yet assessed the impact, if any, that the new amended standards will have on its financial statements or whether to early adopt any of the new requirements.

IFRS 9 "Financial Instruments"

The result of the first phase of the IASB's project to replace IAS 39, "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value.

IFRS 10 "Consolidated Financial Statements"

Replaces Standing Interpretations Committee 12, "Consolidation - Special Purpose Entities" and the consolidation requirements of IAS 27 "Consolidated and Separate Financial Statements". The new standard replaces the existing risk and rewards based approaches and establish control as the determining factor when determining whether an interest in another entity should be included in the consolidated financial statements.

IFRS 11 “Joint Arrangements”

Replaces IAS 31 “Interests in Joint Ventures” along with amending IAS 28 “Investment in Associates”. IFRS 11, “Joint Arrangements”, requires a venturer to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation the venturer will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. Under existing IFRS, entities have the choice to proportionately consolidate or equity account for interests in joint ventures.

IFRS 12 “Disclosure of Interests in Other Entities”

Provides comprehensive disclosure requirements on interests in other entities, including joint arrangements, associates, and special purpose vehicles. The new disclosure requires information that will assist financial statement users in evaluating the nature, risks and financial effects of an entity’s interest in subsidiaries and joint arrangements.

IFRS 13 “Fair Value Measurement”

Provides a common definition of fair value within IFRS. The new standard provides measurement and disclosure guidance and applies when IFRS requires or permits the item to be measured at fair value, with limited exceptions. This standard does not determine when an item is measured at fair value and as such does not require new fair value measurements.

Additional information relating to the Company may be found on www.sedar.com or on 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 judgements and have been properly reflected in the accompanying financial statements.

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

Deloitte LLP has been appointed by the Shareholders to serve as the Company's external auditors. They have examined the financial statements and provided their auditor's report. The audit committee has reviewed these financial statements with management and the auditors, and has reported to the Board of Directors. The Board of Directors has approved the financial statements as presented in this annual report.

George F. Fink

Chief Executive Officer and
Chairman of the Board

March 21, 2013

Robb D. Thompson

Chief Financial Officer and
Corporate Secretary

March 21, 2013

INDEPENDENT AUDITOR'S REPORT

TO THE SHAREHOLDERS OF BONTERRA ENERGY CORP.

We have audited the accompanying financial statements of Bonterra Energy Corp., which comprise the statements of financial position as at December 31, 2012 and 2011, and the statements of comprehensive income, statements of changes in equity and statements of cash flows for the years then ended, and the notes to the financial statements.

MANAGEMENT'S RESPONSIBILITY FOR THE FINANCIAL STATEMENTS

Management is responsible for the preparation and fair presentation of these financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of financial statements that are free from material misstatement, whether due to fraud or error.

AUDITOR'S RESPONSIBILITY

Our responsibility is to express an opinion on these financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

OPINION

In our opinion, the financial statements present fairly, in all material respects, the financial position of Bonterra Energy Corp. as at December 31, 2012 and 2011, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

Deloitte LLP

Chartered Accountants

Calgary, Alberta

March 21, 2013

FINANCIAL STATEMENTS

STATEMENT OF FINANCIAL POSITION

As at ($ 000s)	Note	**December 31, 2012**	December 31, 2011
Assets			
Current			
Accounts receivable		**19,158**	17,094
Crude oil inventory		**797**	1,092
Prepaid expenses		**1,635**	1,688
Investments		**4,136**	6,266
		25,726	26,140
Investment in related party	5	**910**	566
Exploration and evaluation assets	7	**1,982**	1,989
Property, plant and equipment	8	**341,452**	274,361
Investment tax credit receivable	9	**27,670**	27,670
Deferred tax asset	9	**22,193**	33,450
		419,933	364,176
Liabilities			
Current			
Accounts payable and accrued liabilities	10	**28,602**	30,716
Due to related parties	11	**12,000**	32,000
Subordinated promissory note	12	**15,000**	15,000
		55,602	77,716
Bank debt	13	**166,808**	69,916
Decommissioning liabilities	14	**34,246**	34,904
		256,656	182,536
Commitments and subsequent events	19, 20		
Shareholders' equity			
Share capital	15	**149,877**	142,567
Contributed surplus		**9,167**	5,302
Accumulated other comprehensive income		**1,620**	2,662
Retained earnings		**2,613**	31,109
		163,277	181,640
		419,933	364,176

See accompanying notes to these financial statements.

On behalf of the Board:

George F. Fink

Director

Bill Woodward

Director

STATEMENT OF COMPREHENSIVE INCOME

For the years ended December 31 ($ 000s, except $ per share)	Note	2012	2011
Revenue			
Oil and gas sales, net of royalties	16	**129,010**	144,700
Other income	17	**6,767**	2,642
		135,777	147,342
Expenses			
Production costs		**41,408**	36,787
Office and administration		**2,121**	2,332
Employee compensation		**3,974**	4,456
Finance costs	4	**5,895**	4,436
Share-based payments	15	**4,241**	2,554
Depletion and depreciation	8	**33,521**	32,699
Impairment of natural gas assets	7,8	**-**	2,585
		91,160	85,849
Earnings before income taxes		**44, 617**	61,493
Deferred income taxes	9	**11,406**	17,885
Net earnings for the year		**33,211**	43,608
Other comprehensive income (loss)			
Unrealized gains (losses) on investments		**1,514**	(1,462)
Deferred taxes on unrealized losses (gains) on investments		**(189)**	266
Realized gains on investments transferred to net earnings		**(2,705)**	(2,126)
Deferred taxes on realized gains on investments transferred to net earnings		**338**	282
Other comprehensive loss for the year		**(1,042)**	(3,040)
Total comprehensive income for the year		**32,169**	40,568
Net earnings per share – basic	15	**1.68**	2.25
Net earnings per share – diluted	15	**1.68**	2.23
Comprehensive income per share – basic	15	**1.63**	2.10
Comprehensive income per share – diluted	15	**1.63**	2.07

See accompanying notes to these financial statements.

STATEMENT OF CASH FLOWS

For the years ended December 31 ($ 000s)	Note	2012	2011
Operating activities			
Earnings before income taxes		**44,617**	61,493
Items not affecting cash			
Share-based payments		**4,241**	2,554
Depletion and depreciation		**33,521**	32,699
Impairment of natural gas assets		**-**	2,585
Unwinding of the fair value of decommissioning liabilities		**886**	954
Gain on sale of property		**(3,616)**	(162)
Gain on sale of investments		**(2,705)**	(2,126)
Investment income		**(161)**	(27)
Interest expense		**5,009**	3,482
Change in non-cash working capital			
Change in accounts receivable		**1,580**	(2,313)
Change in crude oil inventory		**194**	(417)
Change in prepaid expenses		**53**	(57)
Change in accounts payable and accrued liabilities		**(3,743)**	3,057
Decommissioning expenditures		**(542)**	(831)
Interest paid		**(5,009)**	(3,482)
Cash provided by operating activities		**74,325**	97,409
Financing activities			
Increase (decrease) in bank debt		**96,892**	(470)
Due to related parties		**(20,000)**	-
Stock option proceeds		**6,934**	7,150
Dividends		**(61,707)**	(58,805)
Cash provided by (used in) financing activities		**22,119**	(52,125)
Investing activities			
Investment income received		**161**	27
Exploration and evaluation expenditures		**(182)**	(309)
Property, plant and equipment expenditures		**(84,593)**	(62,615)
Proceeds on sale of property		**3,753**	238
Purchase of investments		**(185)**	-
Proceeds on sale of investments		**3,485**	3,991
Acquisition	6	**(17,108)**	-
Change in non-cash working capital			
Change in accounts payable and accrued liabilities		**1,629**	10,820
Change in accounts receivable		**(3,404)**	2,564
Cash used in investing activities		**(96,444)**	(45,284)
Net cash inflow		**-**	-
Cash, beginning of year		**-**	-
Cash, end of year		**-**	-

See accompanying notes to these financial statements.

STATEMENT OF CHANGES IN EQUITY

($ 000s, except number of shares outstanding)

	Number of shares outstanding (Note 15)	Share capital (Note 15)	Contributed surplus [1]	Accumulated other comprehensive income [2]	Retained earnings	Total shareholders' equity
January 1, 2011	19,219,541	135,030	3,135	5,702	46,306	190,173
Share-based payments			2,554			2,554
Exercise of options	351,775	7,150				7,150
Transfer to share capital on exercise of options		387	(387)			-
Comprehensive income (loss)				(3,040)	43,608	40,568
Dividends					(58,805)	(58,805)
December 31, 2011	19,571,316	142,567	5,302	2,662	31,109	181,640
Share-based payments			4,241			4,241
Exercise of options	338,225	6,934				6,934
Transfer to share capital on exercise of options		376	(376)			-
Comprehensive income (loss)				(1,042)	33,211	32,169
Dividends					(61,707)	(61,707)
December 31, 2012	**19,909,541**	**149,877**	**9,167**	**1,620**	**2,613**	**163,277**

(1) Contributed surplus comprises of share-based payments.

(2) Accumulated other comprehensive income comprises of unrealized gains and losses on available-for-sale investments.

See accompanying notes to these financial statements.

NOTES TO THE FINANCIAL STATEMENTS

As at and for the years ended December 31, 2012 and 2011.

1. NATURE OF BUSINESS AND SEGMENT INFORMATION

Bonterra Energy Corp. (Bonterra or the Company) is a public company listed on the Toronto Stock Exchange 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 being the development and production of oil and natural gas in the Western Canadian Sedimentary Basin.

2. BASIS OF PREPARATION

A) STATEMENT OF COMPLIANCE

These financial statements have been prepared by management in accordance with International Financial Reporting Standards (IFRS), as issued by the International Accounting Standards Board (IASB).

The financial statements were authorized for issue by the Company's Board of Directors on March 21, 2013.

B) CHANGE IN ACCOUNTING ESTIMATE

Property, Plant and Equipment

On January 1, 2012, the Company prospectively began depleting oil and gas properties using the unit-of-production method over their proved plus probable developed reserve life (Total Developed Method), a change from the unit–of-production method over their proved developed reserve life (Proved Developed Method). The change of estimate was due to the Total Developed Method providing a better reflection of the estimated service life of the related assets. For 2012, the Company recorded less depletion and depreciation of $9,692,000 under the Total Developed Method, compared to what would have been recorded using the Proved Developed Method. The Company believes it is not practical to estimate the effect on depletion and depreciation expense for future periods.

C) BASIS OF MEASUREMENT

These financial statements have been prepared on a historical cost basis, except for certain financial instruments and share-based payment transactions which are measured at fair value.

D) FUNCTIONAL AND PRESENTATION CURRENCY

The Company's functional and presentation currency is the Canadian dollar.

Monetary assets and liabilities are translated into Canadian dollars at the rates prevailing on the reporting date. Non-monetary assets and liabilities are translated into Canadian dollars at the rates prevailing on the transaction dates. Exchange gains and losses are recorded as income or expense in the period in which they occur.

E) SIGNIFICANT ACCOUNTING ESTIMATES AND JUDGMENTS

The timely preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities as at the date of the statement of financial position as well as the reported amounts of revenues, expenses and cash flows during the periods presented. Such estimates relate primarily to unsettled transactions and events as of the date of the financial statements. Actual results could differ materially from estimated amounts.

Estimates and underlying assumptions are reviewed on an ongoing basis. Revisions to accounting estimates are recognized in the year in which the estimates are revised and in any future years affected. The following are the estimates and judgments applied by management that most significantly affect the Company's financial statements.

Exploration and Evaluation Expenditures

Exploration and evaluation costs are initially capitalized with the intent to establish commercially viable reserves. Exploration and evaluation assets include undeveloped land and costs related to exploratory wells. The Company is required to make estimates and judgments about future events and circumstances regarding the future economic viability of extracting the underlying resources. Changes to project economics, resource quantities, expected production techniques, unsuccessful drilling, expired mineral leases, production costs and required capital expenditures are important factors when making this determination. To the extent a judgment is made, that the underlying reserves are not viable, the exploration and evaluation costs will be impaired and charged to net earnings.

Impairment of Non-Financial Assets

Property, plant and equipment are aggregated into cash generating units (CGUs) based on their potential ability to generate largely independent cash flows and are used for impairment assessment. CGUs have been determined based on similar geological structure, shared infrastructure, geographical proximity, commodity type, and similar markets risks, oil and gas prices and other assumptions will change in the future, which may impact the Company's recoverable amounts and may therefore require a material adjustment to the carrying value of property, plant and equipment. The determination of the Company's CGUs is subject to management's judgment.

Reserves Estimation

The capitalized costs of oil and gas properties are depleted on a unit-of-production basis at a rate calculated by reference to proved plus probable developed reserves determined in accordance with National Instrument 51-101 and the Canadian Oil and Gas Evaluation handbook. Commercial reserves are determined using best estimates of oil and gas in place, recovery factors and future oil and gas prices. Amounts used for impairment calculations are also based on estimates of crude oil and natural gas reserves and future costs required to develop those reserves.

Share-based Payments

The Company measures the cost of equity-settled transactions with employees by reference to the fair value of the equity instruments at the date they are granted. Estimating the fair value requires the determination of the most appropriate valuation model for a grant, which is dependent on the terms and conditions of the grant. This also requires the determination of the most appropriate inputs to the valuation model including the expected life of the option, risk free interest rates, volatility and dividend yield.

Decommissioning and Restoration Costs

Decommissioning and restoration costs will be incurred by the Company at the end of the operating lives of the Company's oil and gas properties. Provisions for decommissioning liabilities are uncertain and cost estimates can vary in response to many factors including timing of abandonment, inflation, change in legal requirements, new restoration techniques and interest rates.

Income Taxes

The Company recognizes the net future tax benefit related to deferred income tax assets to the extent that it is probable that the deductible temporary differences will reverse in the foreseeable future. Assessing the recoverability of deferred tax assets and investment tax credit receivable requires the Company to make significant estimates related to expectations of future taxable income. The provision for income taxes is based on judgments in applying income tax law and estimates of the timing, likelihood and reversal of temporary differences between the accounting and tax basis of assets and liabilities. The ability to realize on the deferred tax assets and investment tax credit receivable recorded on the balance sheet may be compromised to the extent that any interpretation of tax law is challenged or taxable income differs significantly from estimates.

Further details regarding accounting estimates and judgments are discussed in Note 3.

F) RECENT ACCOUNTING PRONOUNCEMENTS

As of January 1, 2013, Bonterra will be required to adopt amendments to IAS 1 "Presentation of Financial Statements" which will require companies to group together items within other comprehensive income that may be reclassified to the net earnings section of the statement of comprehensive income. Bonterra does not expect a material impact as a result of the amendments.

Each of the additional new standards outlined below is effective for annual periods beginning on or after January 1, 2013 with early adoption permitted, except for IFRS 9 "Financial Instruments" which is effective for annual periods beginning on or after January 1, 2015. The Company has not yet assessed the impact, if any, that the new amended standards will have on its financial statements or whether to early adopt any of the new requirements.

IFRS 9 "Financial Instruments"

The result of the first phase of the IASB's project to replace IAS 39, "Financial Instruments: Recognition and Measurement". The new standard replaces the current multiple classification and measurement models for financial assets and liabilities with a single model that has only two classification categories: amortized cost and fair value.

IFRS 10 "Consolidated Financial Statements"

Replaces Standing Interpretations Committee 12, "Consolidation - Special Purpose Entities" and the consolidation requirements of IAS 27 "Consolidated and Separate Financial Statements". The new standard replaces the existing risk and rewards based approaches and establish control as the determining factor when determining whether an interest in another entity should be included in the consolidated financial statements.

IFRS 11 "Joint Arrangements"

Replaces IAS 31 "Interests in Joint Ventures" along with amending IAS 28 "Investment in Associates". IFRS 11, "Joint Arrangements," requires a venturer to classify its interest in a joint arrangement as a joint venture or joint operation. Joint ventures will be accounted for using the equity method of accounting whereas for a joint operation the venturer will recognize its share of the assets, liabilities, revenue and expenses of the joint operation. Under existing IFRS, entities have the choice to proportionately consolidate or equity account for interests in joint ventures.

IFRS 12 "Disclosure of Interests in Other Entities"

Provides comprehensive disclosure requirements on interests in other entities, including joint arrangements, associates, and special purpose vehicles. The new disclosure requires information that will assist financial statement users in evaluating the nature, risks and financial effects of an entity's interest in subsidiaries and joint arrangements.

IFRS 13 "Fair Value Measurement"

Provides a common definition of fair value within IFRS. The new standard provides measurement and disclosure guidance and applies when IFRS requires or permits the item to be measured at fair value, with limited exceptions. This standard does not determine when an item is measured at fair value and as such does not require new fair value measurements.

3. SIGNIFICANT ACCOUNTING POLICIES

A) REVENUE RECOGNITION

Revenues from the sale of petroleum and natural gas are recorded when the significant risks and rewards of ownership have been transferred to the customer. This generally occurs when the product is physically transferred into a third-party pipeline or when the delivery truck arrives at a customer's receiving location. Items such as royalties from crown, freehold, gross overriding (GORR) and Saskatchewan surcharge are netted against revenue. These items are netted to reflect the deduction for other parties' proportionate share of the revenue.

Administration fee income is recorded when management services and office administration are provided (see related parties disclosure Note 11 and Note 17).

B) JOINTLY CONTROLLED OPERATIONS

Certain exploration, development and production activities are conducted jointly with others. These financial statements reflect only the Company's interests in such activities. A jointly controlled operation involves the use of assets and other resources of the Company and those of other venturers rather than through the establishment of a corporation, partnership or other entity. The Company has no interests in jointly controlled entities. The Company recognizes in its financial statements the interest in assets that it owns, the liabilities and expenses that it incurs and its share of income earned by the joint venture through proportionate consolidation. The Company has no material individual capital commitments in any joint venture interest or in any joint venture.

C) INVENTORIES

Inventories consist of crude oil. Crude oil stored in the Company's tanks is valued on a first in first out basis at the lower of cost or net realizable value. Inventory cost for crude oil is determined based on combined average per barrel operating costs, depletion and depreciation for the period and net realizable value is determined based on estimated sales price less transportation costs.

D) INVESTMENTS AND INVESTMENT IN RELATED PARTY

Investments and investment in related party consist of equity securities classified on initial recognition as available-for-sale and are carried at fair value. Fair value is determined by multiplying the period end trading price of the investments by the number of common shares held as at period end. Unrealized holding gains and losses are recognized in other comprehensive income. Net gains and losses arising on disposal are recognized in net earnings.

E) EXPLORATION AND EVALUATION ASSETS

General exploration or evaluation (E&E) expenditures incurred prior to acquiring the legal right to explore are charged to expense as incurred.

E&E expenditures represent undeveloped land costs, licenses and exploration well costs.

Undeveloped land costs, licenses and exploration well costs are initially capitalized and, if subsequently determined to have not found sufficient reserves to justify commercial production, are charged to expense. E&E assets continue to be capitalized as long as sufficient progress is being made to assess the reserves and economic viability of the asset. Once technical feasibility and commercial viability has been established, E&E assets are transferred to property, plant and equipment (PP&E). E&E assets are assessed for impairment either annually, upon transfer to PP&E assets or whenever indications of impairment exist to ensure they are not carried above their recoverable amounts.

F) PROPERTY, PLANT AND EQUIPMENT

PP&E assets include transferred-in E&E costs, development drilling and other subsurface expenditures. PP&E assets are carried at cost less depletion and depreciation of all development expenditures and include all other expenditures associated with PP&E assets.

When commercial production in an area has commenced, PP&E properties, excluding surface costs are depleted using the unit-of-production method over their total developed reserve life. Total developed reserves are determined annually by qualified independent reserve engineers. Changes in factors such as estimates of total developed reserves that affect unit-of-production calculations are accounted for on a prospective basis. Surface costs such as production facilities and furniture, fixtures and other equipment are depreciated over their estimated useful lives.

Oil and Gas Properties

The initial cost of an asset is comprised of its purchase price or construction cost, including expenditures such as drilling costs, the present value of the initial and changes in the estimate of any decommissioning obligation associated with the asset and finance charges on qualifying assets, that are directly attributable to bringing the asset into operation and to its present location.

Production Facilities

Production facilities are comprised of costs related to petroleum and natural gas plant and production equipment.

Depletion and Depreciation

Depletion and depreciation is recognized in the statement of comprehensive income. Production facilities, furniture, fixtures and other equipment are depreciated over the individual assets' estimated economic lives.

These assets are depreciated on a declining balance method as follows:

Production facilities	10 percent per year
Furniture, fixtures and other equipment	10 percent to 20 percent per year

G) IMPAIRMENT OF ASSETS

Impairment of Financial Assets

A financial asset is considered to be impaired if objective evidence indicates that one or more events have had a negative effect on the estimated future cash flows of that asset. An impairment loss in respect of a financial asset measured at amortized cost is calculated as the difference between its carrying amount and the present value of the estimated future cash flows discounted at the original effective interest rate. Individually significant financial assets are tested for impairment on an individual basis. The remaining financial assets are assessed collectively in groups that share similar credit risk characteristics. An impairment loss in respect of an available-for-sale financial asset is calculated by reference to its current fair value.

All impairment losses are recognized in net earnings. An impairment loss is reversed if there is an indicator that the impairment reversal can be related objectively to an event occurring after the impairment loss was recognized. Any subsequent recovery of an impairment loss in respect of an investment in an equity instrument classified as available-for-sale is reversed through other comprehensive income instead of net earnings. For financial assets measured at amortized cost, the reversal is recognized in net earnings.

Impairment of Non-Financial Assets

The carrying amounts of the Company's non-financial assets are reviewed at the end of each reporting period to determine whether there is any indication of impairment. If such indication exists, then the assets' carrying amounts are assessed for impairment.

For the purpose of impairment testing, assets (which include E&E and PP&E assets) are grouped together into the smallest group of assets that generates cash flows from continuing use that are largely independent of the cash flows of other assets or groups of assets (the cash-generating unit or CGU). The recoverable amount of an asset or a CGU is the greater of its value-in-use (VIU) and its fair value less costs to sell (FVLCS).

An impairment loss is recognized if the carrying amount of an asset or its CGU exceeds its recoverable amount. Impairment losses are recognized in the statement of comprehensive income. Impairment losses recognized in respect of a CGU are allocated first to reduce the carrying amount of any goodwill allocated to the CGU and then to reduce the carrying amount of the other assets of the CGU on a pro-rata basis.

An impairment loss in respect of goodwill cannot be reversed. In respect of other assets, impairment losses recognized in prior periods are assessed at each reporting date for any indications that the loss has decreased or no longer exists. If the amount of the impairment loss decreases in a subsequent period and the decrease can be objectively related to an event occurring after the impairment was recognized, the impairment loss is reversed only to the extent that the asset's carrying amount does not exceed the carrying amount that would have been determined, net of depletion and depreciation, if no impairment loss had been recognized.

H) DECOMMISSIONING LIABILITIES

The fair value of the statutory, contractual, constructive or legal liabilities associated with the retirement and reclamation of oil and gas properties is recorded when incurred, with a corresponding increase to the carrying amount of the related PP&E. The amount recognized is the estimated cost of decommissioning, discounted to its present value using the Company's risk free rate. Changes in the estimated timing of decommissioning or decommissioning cost estimates and changes to the risk free rates are dealt with prospectively by recording an adjustment to the provision, and a corresponding adjustment to property, plant and equipment. The unwinding of the discount on the decommissioning provision is charged to net earnings as a finance cost.

The Company recognizes a decommissioning liability in the period in which it is incurred when a reasonable estimate of the fair value can be made. On a periodic basis, management will review these estimates and changes and if there are any, they will be applied prospectively. The fair value of the estimated provision is recorded as a long-term liability, with a corresponding increase in the carrying amount of the related asset. The capitalized amount is depleted on a unit-of-production basis over the life of the proved plus probable developed reserves. The liability amount is increased each reporting period due to the passage of time and this amount is charged to earnings in the period. Actual costs incurred upon settlement of the obligations are charged against the provision to the extent of the liability recorded and the remaining balance of the actual costs is recorded in the statement of comprehensive income.

I) INCOME TAXES

Tax expense comprises current and deferred taxes. Tax is recognized in the statement of comprehensive income or directly in equity.

Current tax expense is based on the results for the period as adjusted for items that are not taxable or not deductible. Current tax is calculated using tax rates and laws that are substantively enacted at the end of the reporting period. Management periodically evaluates positions taken in tax returns with respect to situations in which applicable tax regulation is subject to interpretation. Provisions are established where appropriate on the basis of amounts expected to be paid to the tax authorities.

Deferred tax is recognized using the liability method, providing for unused tax losses, unused tax credits and temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is not recognized for the following temporary differences: the initial recognition of assets and liabilities in a transaction that is not a business combination and that affects neither accounting nor taxable profit, and differences relating to investments in subsidiaries to the extent that they are unlikely to be reversed in the foreseeable future.

Deferred tax is measured at the tax rates that are expected to be applied to the temporary differences when they reverse, based on the laws that have been enacted or substantively enacted by the reporting date.

A deferred tax asset is recognized to the extent that it is probable that future taxable profits will be available against which unused tax losses, unused tax credits and temporary differences can be utilized. Deferred tax assets are reviewed at each balance date and are reduced to the extent that it is no longer probable that the related tax benefit will be realized.

The amount and timing of reversals of temporary differences will also depend on the Company's future operating results, and acquisitions and dispositions of assets and liabilities. A significant change in any of the preceding assumptions could materially affect the Company's estimate of the deferred income tax asset.

J) SHARE-BASED PAYMENTS

The Company accounts for share-based payments using the fair-value method of accounting for stock options granted to directors, officers, employees and other service providers using the Black-Scholes option pricing model. Share-based payments are recognized through the statement of comprehensive income over the vesting period with a corresponding amount reflected in contributed surplus in equity. For awards issued in tranches that vest at different times, the fair value of each tranche is recognized over its respective vesting period.

At the grant date and at the end of each reporting period, the Company assesses and re-assesses for subsequent periods its estimates of the number of awards that are expected to vest and recognizes the impact of the revisions in the statement of comprehensive income. Upon exercise of share-based options, the proceeds received net of any transaction costs and the fair value of the exercised share-based options is credited to share capital.

K) FINANCIAL INSTRUMENTS

Financial instruments are measured at fair value on initial recognition of the instrument and are classified into one of the following five categories: fair-value through profit or loss, loans and receivables, held-to-maturity investments, available-for-sale financial assets and financial liabilities at amortized cost.

Subsequent measurement of financial instruments is based on their initial classification. Fair-value through profit or loss financial instruments are measured at fair value and changes in fair value are recognized in the statement of comprehensive income. Available-for-sale financial instruments are measured at fair value with changes in fair value recorded in other comprehensive income until the instrument is derecognized or impaired. The remaining categories of financial instruments are recognized at amortized cost using the effective interest rate method.

Cash and restricted cash are classified as fair-value through profit and loss. Accounts receivable are classified as loans and receivables which are measured at amortized cost. Investments are classified as available-for-sale which is measured at fair value and any gains or losses are recognized in other comprehensive income in the period they occur. Accounts payable and accrued liabilities, bank debt, subordinated promissory note and amounts due to related parties are classified as financial liabilities at amortized cost.

Bank debt, subordinated promissory note and due to related parties are classified as current liabilities unless the Company has an unconditional right to defer settlement of the liability for at least 12 months after the reporting date.

L) RISK MANAGEMENT CONTRACTS

The Company is exposed to market risks resulting from fluctuations in commodity prices, foreign currency exchange rates and interest rates in the normal course of its business. The Company may use a variety of instruments to manage these exposures. For transactions where hedge accounting is not applied, the Company accounts for such instruments using the fair value method by initially recording an asset or liability, and recognizing changes in the fair value of the instruments in earnings as unrealized gains or losses on risk management contracts. Fair values of financial instruments are based on third party quotes or valuations provided by independent third parties. Any realized gains or losses on risk management contracts are recognized in net earnings in the period they occur.

The Company may elect to use hedge accounting when there is a high degree of correlation between the price movements in the financial instruments and the items designated as being hedged and the Company has documented the relationship between the instruments and the hedged item as well as its risk management objective and strategy for undertaking hedge transactions. During the years ended December 31, 2012 and December 31, 2011, the Company did not designate any of its financial instruments as hedges. There were no risk management contracts outstanding as at December 31, 2012 and December 31, 2011.

M) NET EARNINGS AND COMPREHENSIVE INCOME PER SHARE

Per share amounts are calculated by dividing the net earnings or comprehensive income attributable to common shareholders of the Company by the weighted average number of common shares outstanding during the reporting period.

Diluted per share amounts are calculated similar to basic per share amounts except that the weighted average common shares outstanding are increased to include additional common shares from the assumed exercise of dilutive share options. The number of additional outstanding common shares is calculated by assuming that the outstanding in-the-money share options were exercised and that the proceeds from such exercises were used to acquire common shares at the average market price during the reporting period.

4. FINANCE COSTS

A breakdown of finance costs for the current and previous year is:

($ 000s)	**December 31, 2012**	December 31, 2011
Interest expense on bank debt	**3,730**	2,272
Interest expense on amounts owing to related parties	**683**	760
Interest expense on subordinated promissory note and other	**596**	450
Unwinding of the fair value of decommissioning liabilities	**886**	954
Total	**5,895**	4,436

5. INVESTMENT IN RELATED PARTY

On October 19, 2012, Pine Cliff Energy Ltd. (Pine Cliff), a company with some common directors and some common management with Bonterra, acquired 100 percent of the issued and outstanding common shares of Geomark Exploration Ltd. (Geomark), pursuant to an arrangement agreement. Geomark became a wholly-owned subsidiary of Pine Cliff and its shares were delisted from the TSX Venture Exchange on October 22, 2012. Consideration for each Geomark Share was 1.5 voting common shares of Pine Cliff. Bonterra now holds 1,034,523 common shares in Pine Cliff (December 31, 2011 – 689,682 common shares in Geomark) which represents 0.7 percent ownership in Pine Cliff’s outstanding common shares. The investment in Pine Cliff is recorded at fair market value.

In addition, Geomark owns 204,633 (December 31, 2011 – 204,633) common shares in Bonterra.

6. ACQUISITION

On June 7, 2012, Bonterra acquired oil and natural gas assets in the Willesden Green area of Alberta for cash consideration of $17,108,000. The results of the Willesden Green oil and gas assets have been included in the financial statements since that date. The Willesden Green oil and gas assets contributed oil and gas sales, net of royalties, of $1,785,000 and operating expenses of $688,000 for the period from June 7, 2012 to December 31, 2012. If the acquisition had occurred on January 1, 2012, total oil and gas sales, net of royalties, would have been approximately $3,416,000 and total operating expenses would have been approximately $1,163,000 for the year ended December 31, 2012.

The acquisition has been accounted for using the acquisition method and the purchase price was allocated to the assets acquired and the liabilities assumed as follows:

Net assets acquired	($ 000s)
Property, plant and equipment	19,603
Decommissioning liabilities	(2,735)
Working capital	240
Total	17,108
Consideration:	
Cash	17,108
Total purchase price	17,108

7. EXPLORATION AND EVALUATION ASSETS

($ 000s)	**E&E assets**
Cost and carrying amount	
Balance at January 1, 2011	4,595
Additions	309
Transfers to property, plant and equipment	(2,001)
Impairment (Note 8)	(914)
Balance at December 31, 2011	**1,989**
Additions	182
Transfers to property, plant and equipment	(189)
Balance at December 31, 2012	**1,982**

8. PROPERTY, PLANT AND EQUIPMENT

Cost ($ 000s)	Oil and gas properties	Production facilities	Furniture, fixtures & other equipment	Total property, plant & equipment
Balance at January 1, 2011	283,484	62,728	1,474	347,686
Additions	58,874	15,019	77	73,970
Transfers from exploration and evaluation assets	2,001	-	-	2,001
Disposal	(166)	(136)	(41)	(343)
Balance at December 31, 2011	**344,193**	**77,611**	**1,510**	**423,314**
Additions	67,003	13,931	183	81,117
Transfers from exploration and evaluation assets	189	-	-	189
Acquisition	16,117	3,486		19,603
Disposal	(261)	(126)	(32)	(419)
Balance at December 31, 2012	**427,241**	**94,902**	**1,661**	**523,804**

Accumulated Depletion and Depreciation ($ 000s)	Oil and gas properties	Production facilities	Furniture, fixtures & other equipment	Total property, plant & equipment
Balance at January 1, 2011	(88,297)	(25,265)	(1,098)	(114,660)
Depletion and depreciation	(27,435)	(5,181)	(83)	(32,699)
Disposal and other	(5)	44	38	77
Impairment	(784)	(887)	-	(1,671)
Balance at December 31, 2011	**(116,521)**	**(31,289)**	**(1,143)**	**(148,953)**
Depletion and depreciation	(27,187)	(6,232)	(102)	(33,521)
Disposal and other	101	-	21	122
Balance at December 31, 2012	**(143,607)**	**(37,521)**	**(1,224)**	**(182,352)**

Carrying amounts as at: ($ 000s)				
December 31, 2011	227,672	46,322	367	274,361
December 31, 2012	**283,634**	**57,381**	**437**	**341,452**

In January 2012, the Company disposed of its Central Alberta Redwater property. The proceeds of disposition was cash of $1,109,000. At the time of disposition, the property had no carrying value resulting in a gain on sale equal to its proceeds.

In June 2012, the Company disposed of a portion of its Central Alberta Tomahawk property. The proceeds of disposition was cash of $2,500,000. At the time of disposition, the property had no carrying value resulting in a gain on sale equal to its proceeds.

IMPAIRMENT

Management has determined four cash generating units for the Company, which are comprised of one core cash-generating unit (CGU) for the Pembina Cardium and Willesden Green assets in Alberta, Canada and three other non-core CGUs.

These CGUs are the Company's producing fields. As part of its annual impairment analysis, the Company assessed its PP&E assets, production facilities, furniture and other equipment by CGU for possible impairment.

The assessment for impairment has been determined based on the value-in-use (VIU) method. VIU was determined on the basis of the discounted expected future cash flows based on the Company's plans to continue to produce total proved and probable reserves.

Projected estimates of cash flows from the CGUs have been determined based on the economic life of the reserves using an inflation rate of 1.5 percent (2011 - 2.0 percent). The pre-tax discount rate applied to the cash flows for the Company's total proved and probable assets is 10 percent (2011 – proved and probable developed assets was 10 percent and probable undeveloped assets was 15 percent).

There were no impairment provisions recorded for the year ended December 31, 2012. In 2011, there were significant reductions in the future commodity price forecasts for natural gas used by the Company's independent reserves evaluator when compared to the previous year resulting in an impairment provision of $2,585,000 for minor natural gas assets in British Columbia.

9. INCOME TAXES

($ 000s)	**December 31, 2012**	December 31, 2011
Deferred tax asset (liability) related to:		
Investments	**(302)**	(308)
Exploration and evaluation assets and property, plant and equipment	**(34,856)**	(27,354)
Decommissioning liabilities	**8,575**	8,737
Corporate tax losses and SR&ED claims	**48,474**	52,067
Corporate capital tax loss	**16,964**	17,212
Unrecorded benefit of capital tax losses	**(16,662)**	(16,904)
Deferred tax asset	**22,193**	33,450

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

($ 000s)	**December 31, 2012**	December 31, 2011
Earnings before taxes	**44,617**	61,493
Combined federal and provincial income tax rates	**25.04%**	26.53%
Income tax provision calculated using statutory tax rates	**11,172**	16,314
Increase (decrease) in taxes resulting from:		
Share-based payments	**1,062**	677
Non-taxable portion of realized gains	**(381)**	(300)
Unrecorded benefit of capital tax losses	**(242)**	31
Recorded benefit (expense) in other comprehensive income	**(189)**	266
Change in effective tax rate	**11**	789
Others	**(27)**	108
Deferred income tax expense	**11,406**	17,885

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	20-100	39,200
Eligible capital expenditures	7	5,924
Canadian oil and gas property expenditures	10	25,114
Canadian development expenditures	30	121,417
Canadian exploration expenditures	100	11,174
Income tax losses carried forward (1)	100	221,272
		424,101

(1) Federal income tax losses carried forward expire in the following years; 2024 - $1,501,000, 2025 - $7,532,000, 2026 - $46,671,000, 2027 - $117,189,000, 2028 - $35,248,000, 2029 - $13,131,000.

The Company has $27,670,000 (December 31, 2011 - $27,670,000) remaining of investment tax credits that expire in the following years; 2019 - $3,469,000, 2020 - $3,059,000, 2021 - $4,667,000, 2022 - $3,909,000, 2023 - $3,155,000, 2024 - $1,995,000, 2025 - $2,257,000, 2026 - $ 2,405,000, 2027 - $2,009,000, 2028 - $745,000.

The Company also has $135,502,000 (December 31, 2011 - $137,289,000) of capital loss carry forwards which can only be claimed against taxable capital gains.

10. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

Total accounts payable and accrued liabilities comprise of the following categories:

($ 000s)	**December 31, 2012**	December 31, 2011
Accounts payable	**20,181**	25,890
Accrued liabilities	**8,421**	4,826
	28,602	30,716

11. TRANSACTIONS WITH RELATED PARTIES

As at December 31, 2012, the Company's CEO, Chairman of the Board and major shareholder has loaned the Company $12,000,000 (December 31, 2011 - $12,000,000). The loan bears interest at Canadian chartered bank prime less 5/8th of a percent and has no set repayment terms but is payable on demand. Security under the debenture is over all of the Company's assets and is subordinated to any and all claims in favour of the syndicate of senior lenders providing credit facilities to the Company. Interest paid on this loan during the year was $286,000 (December 31, 2011 - $285,000).

On November 9, 2012, Bonterra repaid the $20,000,000 (December 31, 2011 - $20,000,000) loan with Geomark. Interest paid on this loan during the year was $397,000 (December 31, 2011 - $475,000).

The Company received a management fee from Geomark of $225,000 for the year (December 31, 2011 - $270,000) for management services and office administration. This fee has been included in other income. With the arrangement agreement between Pine Cliff and Geomark, the management agreement between Bonterra and Geomark was terminated effective October 19, 2012.

The Company received a management fee of $60,000 for the year ended December 31, 2012 (December 31, 2011 - $60,000) for management services and office administration from Pine Cliff. This fee has been included in other income. As at December 31, 2012, the Company had an account receivable from Pine Cliff of $45,000 (December 31, 2011 - $4,000).

COMPENSATION FOR KEY MANAGEMENT PERSONNEL

($ 000s)	**December 31, 2012**	December 31, 2011
Compensation	**1,529**	1,352
Share-based payments	**2,445**	1,289
Total compensation	**3,974**	2,641

Key management personnel are those persons, including all directors, having authority and responsibility for planning, directing and controlling the activities of the Company.

12. SUBORDINATED PROMISSORY NOTE

As at December 31, 2012, Bonterra has borrowed $15,000,000 (December 31, 2011 - $15,000,000) from a private investor, in exchange for a Subordinated Promissory Note. The terms of the Subordinated Promissory Note are that it bears interest at three percent and is payable after thirty days written notice by either party. Security consists of a floating demand debenture totaling $15,000,000 over all of the Company's assets and is subordinated to any and all claims in favor of the syndicate of senior lenders providing credit facilities to the Company. Interest paid on the subordinated promissory note during the year was $451,000 (December 31, 2011 - $450,000).

The Company's bank agreement requires that the above loan can only be repaid should the Company have sufficient available borrowing limits under the Company's credit facility.

13. BANK DEBT

As at December 31, 2012, the Company has a bank facility consisting of $160,000,000 syndicated revolving credit facility and a $20,000,000 non-syndicated revolving credit facility. Amounts drawn under the facilities at December 31, 2012 were $166,808,000 (December 31, 2011 - $69,916,000). Amounts borrowed under the credit facilities at December 31, 2012 bear interest at a floating rate based on the applicable Canadian prime rate, which is presently three percent or Banker's Acceptance rate, plus between 0.75 percent and 3.50 percent, depending on the type of borrowing and the Company's consolidated total funded debt to consolidated cash flow. The terms of the revolving credit facilities provided that the loan is revolving to April 25, 2013 and with a maturity date of April 25, 2014 and is subject to annual review. The revolving credit facilities have no fixed terms of repayment.

The amount available for borrowing under the credit facilities is reduced by outstanding letters of credit. Letters of credit totaling $400,000 were issued as at December 31, 2012 (December 31, 2011 - $400,000). Security for credit facilities consists of various and floating demand debentures totaling $300,000,000 over all of the Company's assets and a general security agreement with first ranking over all personal and real property.

The following is a list of the material covenants on the banking facility:

- The Company is required to not exceed $180,000,000 in consolidated debt (includes working capital but excludes amounts due to related parties and subordinated promissory note).
- Dividends paid in the current quarter shall not exceed 80 percent of the average available cash flow for the preceding four fiscal quarters.

Available cash flow is defined to be cash provided by operating activities excluding gains on sale of property and investments, the change in non-cash working capital and decommissioning liabilities settled and including all net proceeds of dispositions included in cash used in investing activities. At December 31, 2012, the Company is in compliance with all covenants.

14. DECOMMISSIONING LIABILITIES

At December 31, 2012, the estimated total undiscounted amount required to settle the decommissioning liabilities was $67,684,000 (December 31, 2011 - $73,475,000). The provision has been calculated assuming a 1.5 percent inflation rate (December 31, 2011 – 2.0 percent inflation rate). These obligations will be settled based on the useful lives of the underlying assets, which extend up to 54 years into the future. This amount has been discounted using a risk-free interest rate of 2.4 percent (December 31, 2011 - 2.5 percent).

Changes to decommissioning liabilities were as follows:

($ 000s)	**December 31, 2012**	December 31, 2011
Decommissioning liabilities, January 1	**34,904**	23,427
Adjustment to decommissioning liabilities	**(3,477)**	11,354
Acquistion	**2,735**	-
Disposals	**(260)**	-
Liabilities settled during the period	**(542)**	(831)
Unwinding of the fair value of decommissioning liabilities	**886**	954
Decommissioning liabilities, end of year	**34,246**	34,904

15. SHAREHOLDERS' EQUITY

AUTHORIZED

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

	December 31, 2012		December 31, 2011	
Issued and fully paid – common shares	**Number**	**Amount ($ 000s)**	Number	Amount ($ 000s)
Balance, beginning of year	**19,571,316**	**142,567**	19,219,541	135,030
Issued pursuant to the Company share option plan	**338,225**	**6,934**	351,775	7,150
Transfer from contributed surplus to share capital		**376**		387
Balance, end of year	**19,909,541**	**149,877**	19,571,316	142,567

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 years ended December 31 is as follows:

	2012	2011
Basic shares outstanding	**19,780,814**	19,341,514
Dilutive effect of share options (1)	**13,120**	212,643
Diluted shares outstanding	**19,793,934**	19,554,157

(1) The Company did not include 1,215,000 share options (December 31, 2011 – 599,000) in the dilutive effect of share options calculation as these share options were anti-dilutive.

For the year ended December 31, 2012, the Company declared and paid dividends of $61,707,000 ($3.12 per share) (December 31, 2011 - $58,805,000 ($3.04 per share)).

The Company provides an equity settled option plan for its directors, officers, employees and consultants. Under the plan, the Company may grant options for up to 1,990,954 (December 31, 2011 – 1,957,131) 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 option plan as of December 31, 2012, and changes during the year ended on those dates is presented below:

	Number of options	**Weighted-average exercise price**
At January 1, 2011	747,000	$20.56
Options granted	1,142,000	54.54
Options exercised	(351,775)	20.32
Options cancelled	(11,000)	14.90
Options forfeited	(58,000)	32.14
At December 31, 2011	1,468,225	$46.63
Options granted	942,000	45.38
Options exercised	(338,225)	20.50
Options cancelled	(18,000)	51.61
Options forfeited	(152,000)	54.07
At December 31, 2012	1,902,000	$49.99

The following table summarizes information about options outstanding at December 31, 2012:

	Options Outstanding			Options Exercisable	
Range of exercise prices	Number outstanding at December 31, 2012	Weighted-average remaining contractual life	Weighted-average exercise price	Number exercisable at December 31, 2012	Weighted-average exercise price
$ 40.00 – $ 49.00	855,000	1.8 years	$44.61	6,000	$48.60
50.00 – 59.00	1,047,000	2.4 years	54.38	442,500	57.96
$ 40.00 – $ 59.00	1,902,000	2.1 years	$49.99	448,500	$57.83

The Company records compensation expense over the vesting period, which ranges between one to three years, based on the fair value of options granted to employees, directors and consultants. In 2012, the Company granted 942,000 stock options (December 31, 2011 – 1,142,000) with an estimated fair value of $3,814,000 or $4.05 per option (December 31, 2011 - $8,394,000 or $7.35 per option) using the Black-Scholes option pricing model with the following key assumptions:

	December 31, 2012	December 31, 2011
Weighted-average risk free interest rate (%) (1)	**1.12**	1.40
Expected life (years)	**1.42**	2.03
Weighted-average volatility (%) (2)	**28.23**	32.41
Forfeiture rate (%)	**-**	-
Weighted average dividend yield	**6.90**	5.53

(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.

The weighted average share price of the options exercised in 2012 was $49.17 (2011 - $53.38).

16. OIL AND GAS SALES, NET OF ROYALTIES

($ 000s)	**December 31, 2012**	December 31, 2011
Oil and gas sales	**142,770**	162,277
Less:		
Crown royalties	**(9,727)**	(12,316)
Freehold, gross overriding royalties and other	**(4,033)**	(5,261)
Oil and gas sales, net of royalties	**129,010**	144,700

17. OTHER INCOME

($ 000s)	**December 31, 2012**	December 31, 2011
Investment income	**161**	27
Administrative income	**285**	327
Gain on sale of property	**3,616**	162
Realized gain on investments	**2,705**	2,126
Other income	**6,767**	2,642

18. FINANCIAL AND CAPITAL 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 parties
- Bank debt
- Subordinated promissory note

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 may enter into various risk management contracts to manage the Company's exposure to commodity price fluctuations. Currently no risk management agreements are in place. 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.

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 amount of dividends, debt facilities or issue new shares.

The Company monitors capital on the basis of the ratio of debt to cash flow. This ratio is calculated using each quarter end net debt (total debt adjusted for working capital) and divided by the preceding twelve months cash flow. The Company believes that a debt level of approximately one and a half year's cash flow is an appropriate level to allow it to take advantage in the future of either acquisition opportunities or to provide flexibility to develop its undeveloped resources by horizontal or vertical drill programs. During the current year the Company exceeded the targeted debt level due to decreasing commodity prices, the Willesden Green asset acquisition, an increased capital drilling program, while sustaining current dividend levels. On January 25, 2013, the Company completed a business acquisition of Spartan Oil Corp. which is expected to increase cash flows, restore targeted debt levels to less than 1.5:1 on an annual basis, and increase its holding in its core area, the Pembina and Willesden Green Cardium properties (see Note 20).

The following section (a) of this note provides a summary of the Company's underlying economic positions as represented by the carrying values, fair values and contractual face values of the Company's financial assets and financial liabilities. The Company's debt to cash flow from operations is also provided.

The following 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.

The following section (c) provides details of the Company's risk management contracts that are used for financial risk management.

A) FINANCIAL ASSETS, FINANCIAL LIABILITIES AND DEBT RATIO

The carrying amounts, fair value and face values of the Company's financial assets and liabilities are shown in the table below.

	As at December 31, 2012			As at December 31, 2011		
($ 000s)	**Carrying value**	**Fair value**	**Face value**	Carrying value	Fair value	Face value
Financial assets						
Accounts receivable	**19,158**	**19,158**	**19,389**	**17,094**	17,094	17,136
Investments	**4,136**	**4,136**	**N/A**	**6,266**	6,266	N/A
Investments in related party	**910**	**910**	**N/A**	**566**	566	N/A
Financial liabilities						
Accounts payable and accrued liabilities	**28,602**	**28,602**	**28,602**	**30,716**	30,716	30,716
Due to related parties	**12,000**	**12,000**	**12,000**	**32,000**	32,000	32,000
Subordinated promissory note	**15,000**	**15,000**	**15,000**	**15,000**	15,000	15,000
Bank debt	**166,808**	**166,808**	**166,808**	**69,916**	69,916	69,916

Financial instruments consisting of accounts receivable, accounts payable and accrued liabilities, due to related parties, subordinated promissory note and bank debt on the statement of financial position are carried at amortized cost. Investments and investments in related party are carried at fair value. All of the fair value items are transacted in active markets. Bonterra classifies the fair value of these transactions according to the following hierarchy based on the amount of observable inputs used to value the instrument.

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are other than quoted prices in active markets included in Level 1. Prices in Level 2 are either directly or indirectly observable as of the reporting date. Level 2 valuations are based on inputs, including quoted forward prices for commodities, time value and volatility factors, which can be substantially observed or corroborated in the marketplace.

Level 3 – Valuations in this level are those with inputs for the asset or liability that are not based on observable market data.

Bonterra's investments and investments in related party have been assessed on the fair value hierarchy described above and are all considered Level 1.

The net debt and cash flow figures as of December 31, 2012 are as follows:

($ 000s)	
Bank debt	**166,808**
Accounts payable and accrued liabilities	**28,602**
Due to related parties	**12,000**
Subordinated promissory note	**15,000**
Current assets	**(25,726)**
Net debt	**196,684**
Cash flow from operations	**74,325**
Net debt to annual cash flow from operations	**2.65**

B) RISKS AND MITIGATIONS

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, including fluctuations in the differential between West Texas Intermediate prices and Bonterra's realized prices, 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. Management, in agreement with the Board of Directors, decided that at least in the near term it will discontinue the use of commodity price agreements. The Company will assume full risk in respect of commodity prices.

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 $160,000,000 syndicated revolving operating line, $20,000,000 non-syndicated operating line, $12,000,000 due to a related party and a $15,000,000 subordinated promissory note. The borrowings under these facilities, except for the subordinated promissory note, 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. The subordinated promissory note is at a fixed interest rate of three percent. 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 $1,340,000.

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 U.S. currency, then converted to Canadian currency. The Company currently has no outstanding risk management agreements. Management, in agreement with the Board of Directors, decided that at least in the near term it will not use commodity price agreements. The Company will assume full risk in respect of foreign exchange fluctuations.

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 $19,158,000 accounts receivable balance at December 31, 2012 (December 31, 2011 - $17,094,000) over 60 percent (2011 – 70 percent) relates to product sales with international oil and gas companies and from the provincial government of Alberta.

The Company assesses quarterly if there has been any impairment of the financial assets of the Company. During the year ended December 31, 2012, there was no material impairment provision required on any of the financial assets of the Company due to historical success of realizing financial assets. The Company does have a credit risk exposure as the majority of the Company's accounts receivable is 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 December 31, 2012, approximately $1,330,000 or 6.9 percent of the Company's total accounts receivable are aged over 90 days and considered past due. 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 December 31, 2012 is $231,000 (December 31, 2011 - $42,000) with the difference 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, accounts payable and accrued liabilities and the continuing availability of subordinated promissory note, due to related parties and bank debt on the statement of financial position. There are no material financial assets that the Company considers past due.

Liquidity Risk

Liquidity risk includes the risk that, as a result of the Company's operational liquidity requirements:

- The Company will not have sufficient funds to settle a transaction on the due date;
- The Company will not have sufficient funds to continue with its dividends;
- The Company will be forced to sell assets at a value which is less than what they are worth; or
- The Company may be unable to settle or recover a financial asset at all.

To help reduce these risks the Company:

- Maintains a portfolio of high-quality, long reserve life oil and gas assets.

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

($ 000s)	Recognized on financial statements	Less than 1 year	Over 1 year to 3 years	4 to 5 years
Accounts payable and accrued liabilities	Yes - Liability	28,602	-	-
Due to related parties	Yes - Liability	12,000	-	-
Subordinated promissory note	Yes - Liability	15,000	-	-
Bank debt	Yes - Liability	-	166,808	-
Office leases	No	538	28	-
Total		56,140	166,836	-

C) RISK MANAGEMENT CONTRACTS

The Company has no outstanding risk management contracts at December 31, 2012.

19. COMMITMENTS

OPERATING LEASES

The Company has entered into leases for buildings and office equipment. These leases have an average life of 0.7 years. There are no restrictions placed upon the lessee by entering into these leases. Future minimum lease payments under non-cancellable operating leases as at December 31, 2012 are as follows:

($ 000s)	**2012**
Within one year	538
After one year but not more than five years	28
Total	566

20. SUBSEQUENT EVENTS

I) ACQUISITION

On January 25, 2013, Bonterra acquired 100 percent of the issued and outstanding common shares of Spartan Oil Corp. (Spartan) pursuant to an arrangement agreement (Spartan Transaction). Spartan was a public oil and gas company with properties in Alberta and Saskatchewan. The acquisition of Spartan, including the complementary light oil assets in Bonterra's core area of the Pembina and Willesden Green Cardium properties, will contribute increased cash flows, controlled infrastructure, positive working capital and no debt which positively affects the Company's net debt to cash flow ratio. Consideration for Spartan shares was 0.1169 voting common shares of Bonterra, which amounted to the issuance of 10,711,405 Bonterra shares valued at $502,258,000, using the closing share price of $46.89 per share on the date of the Spartan Transaction. The exchange ratio for the transaction represents a deemed price of $5.03 per Spartan Share. The Spartan Transaction will be accounted for as a business combination with Bonterra identified as the acquirer.

The preliminary purchase price allocation using the acquisition method was allocated to the assets acquired and the liabilities assumed as follows:

Net assets acquired:	($ 000s)
Exploration and evaluation assets	8,829
Property, plant and equipment	462,269
Goodwill	98,369
Working capital	10,685
Decommissioning liabilities	(11,657)
Deferred tax liability	(66,237)
Total	502,258

Consideration:	
Bonterra shares (10,711,405 shares at $46.89)	502,258
Total purchase price	502,258

The purchase price allocation is subject to change as of the issue date of these financial statements. Bonterra does not believe it is practical to estimate the effect on net earnings for future periods. On March 1, 2013, Spartan was amalgamated with Bonterra.

II) DIVIDENDS

Subsequent to December 31, 2012, the Company has declared the following dividends:

Date declared	Record date	$ per share	Date payable
January 3, 2013	January 15, 2013	0.26	January 31, 2012
February 4, 2013	February 15, 2013	0.26	February 28, 2013
March 4, 2013	March 15, 2013	0.28	March 28, 2013

III) BANK FACILITY

The Company's banking syndicate have provided approvals in connection with the annual redetermination of the borrowing base, subject to normal closing conditions. Management expects that on or around March 28, 2013, the Company will amend its bank facilities under similar terms and conditions with exception of extending the revolving period and maturity date, and increasing the total syndicated and non-syndicated credit facilities to $250 million from $180 million. In addition, security for the credit facilities, consisting of various and floating demand debentures, will increase to $400 million from $300 million.

CORPORATE INFORMATION

BOARD OF DIRECTORS

G.J. Drummond, Nassau, Bahamas

G.F. Fink, Calgary, Alberta

R.M. Jarock, Calgary, Alberta

C.R. Jonsson, Vancouver, British Columbia

F.W. Woodward, Calgary, Alberta

OFFICERS

B.A. Curtis – Vice President, Business Development

G.F. Fink – Chief Executive Officer and Chairman of the Board

A. Neumann – Vice President, Engineering and Operations

R.D. Thompson – Chief Financial Officer and Secretary

REGISTRAR & TRANSFER AGENT

Olympia Trust Company, Calgary, Alberta

AUDITORS

Deloitte LLP, Calgary, Alberta

SOLICITORS

Borden Ladner Gervais LLP, Calgary, Alberta

BANKERS

CIBC, Calgary, Alberta

Alberta Treasury Branch, Calgary, Alberta

National Bank of Canada, Calgary, Alberta

STOCK LISTING

The Toronto Stock Exchange

Trading Symbol: BNE

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